Climate project methodology No. 0018

Electricity and heat generation from biomass

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1. Terms and Definitions

1. The following definitions apply for the purpose of this methodology[1]:

(a) **Cogeneration plant** is a facility that simultaneously produces heat and electricity[2].

(b) **Dedicated plantations** are plantations that are newly established as part of the project activity for the purpose of supplying cultivated biomass to the project plant.

(c) **Greenfield power plant** is a new renewable energy power plant that is constructed and operated at a site where no renewable energy power plant was operated prior to the implementation of the project activity.

(d) **Heat** is useful thermal energy that is generated in a heat generator (e.g. a boiler, a cogeneration plant, thermal solar panels, etc.) and transferred to a heat carrier (e.g. hot liquids, hot gases, steam, etc.) for utilization in thermal applications and processes, including power generation. For the purposes of this methodology, heat does not include waste heat, i.e. heat that is transferred to the environment without utilization, for example, heat in flue gas, heat transferred to cooling towers or any other heat losses. Note that heat refers to the *net* quantity of thermal energy that is transferred to a heat carrier at the heat generation unit.

(e) **Heat generator** is a device designed to generate heat energy by combustion of fuel[3]. This includes, for example, a boiler that supplies steam or hot water, a heater that supplies hot oil or thermal fluid, or a furnace that supplies hot gas or combustion gases. When several heat generators are included in one project activity, each heat generator is referred to as “unit”.

(f) **Heat-to-power ratio** is the quantity of process heat recovered from a heat engine per unit of electricity generated in the same heat engine, measured in the same energy units. For example, a heat engine producing 1 MWh_{el} of electricity and 2 MWh_{th} of process heat has a heat-to-power ratio of 2.

(g) **Net quantity of electricity generation** is the electricity generated by a power plant unit after exclusion of parasitic and auxiliary loads, i.e. the electricity consumed by the auxiliary equipment of the power plant unit (e.g. pumps, fans, flue gas treatment, control equipment etc.) and equipment related to fuel handling and preparation.

(h) **Process heat** is the useful heat that is not used for electric power generation. It could include the heat used for mechanical power generation, where applicable.

(i) **Power** is electric power, unless explicitly mentioned otherwise.

[1] When using the regulations and sets of rules referenced in this methodology, it is recommended to check the validity of reference documents in the public information system: on the official website of the federal executive body in the field of standardization on the Internet or according to the annual information index "National Standards".

[2] IECTS 62282-9-102:2021. Fuel cell technologies. Part 9-102. Methodology for assessing the environmental performance of fuel cell power plants in the framework of a life cycle review. Stationary cogeneration power plants based on fuel cells for living quarters. Product category rules for development of environmental declaration.

[3] SP 281.1325800.2016. Built-in Boiler Rooms with a Capacity of up to 360 kW. Design and Installation Rules.

(j) **Power plant** is a power plant designed for the production of electrical energy, containing a construction part, energy conversion equipment and necessary auxiliary equipment according to GOST 19431-84[4] [5].

(k) **Power-only plant** is a power plant, to which the following conditions apply:

(i) all heat engines of the power plant produce only power and do not cogenerate heat; and

(ii) the thermal energy (e.g. steam) produced in the equipment of the power plant (e.g. a boiler) is only used in heat engines (e.g. turbines or motors) and not for other processes (e.g. heating purposes or as feedstock in processes); for example, in the case of a power plant with a steam header, this means that all steam supplied to the steam header must be used in turbines.

(l) **Power-and-heat plant** is a power plant that converts the chemical energy of fuel into electrical energy or electrical energy and heat[6]. Power-and-heat plants encompass two broad categories of power plants: cogeneration plants (as defined above) and plants in which heat and power are produced at the same installation although not in cogeneration mode, e.g. a common heat header supplies heat for both process heat and power generation.

(m) **Crediting period** is 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 of this methodology.

(n) **Data coverage period** is the period for which activity data on the operation of buildings (i.e. electricity consumed, heat energy consumed, fuel consumed and hot/chilled water consumed) are collected for the establishment or update of a baseline.

(o) **Data currentness** is the time gap between the end of the data coverage period and the submission of the estimated baseline (applicable to the conservative baseline estimation approach).

(p) **PDD** is the Project Design Document that describes the project activity.

[4] GOST 24291-90 Interstate Standard. The Electrical Part of the Power Plant and the Electrical Network. Terms and Definitions.

[5] Reference methodologies developed within the framework of the Clean Development Mechanism (ACM0006) use the following interpretation for this term: **Power plant** is an installation that generates electric power through the conversion of heat to power using a heat engine. The heat is produced in a heat generator and consumed in a heat engine (e.g. steam turbine) coupled to an electricity generator.

[6] GOST 19431-84. Power and Electrification. Terms and Definitions.

2. Scope and applicability

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

Table 1. Methodology key elements

Typical project(s)	Co-generation of power and heat using biomass. Typical activities are construction of a new plant, capacity expansion, energy efficiency improvements or fuel switch projects
Type of GHG emissions mitigation action	Renewable energy; energy efficiency; fuel switch; GHG emission avoidance

3. This methodology is unaffected by any GHG programs[7]. If a GHG program is applied[8], the requirements of this program supplement the requirements of the methodology. This methodology is based on the existing methodology developed under the Clean Development Mechanism of the Kyoto Protocol (ACM0006), and includes its adaptation to the current Russian regulations and standards.

2.1. Scope

4. This methodology is applicable to project activities that operate biomass (co-)fired power-and-heat plants.[9] The project activity may include the following activities or, where applicable, combinations of these activities:

(a) Installation of new plants at a site where currently no power or heat generation occurs (Greenfield projects).

(b) Installation of new plants at a site where currently power or heat generation occurs. The new plant replaces, or is operated next to, the existing plants (capacity expansion projects).

(c) Improvement of the energy efficiency of existing biomass-based power-and-heat plants (energy efficiency improvement projects), which can also lead to a capacity expansion, e.g. by retrofitting the existing plant.

(d) Total or partial replacement of fossil fuels by biomass in existing power-and-heat plants or in new power-and-heat plants that would have been built in the absence of the project (fuel switch projects), e.g. by increasing the share of biomass use as compared to the baseline by way of retrofitting an existing plant to use biomass.

[7] Greenhouse gas program, GHG program is a voluntary or mandatory international, national or subnational system or scheme that registers, accounts for or manages GHG emissions, GHG removals, GHG emission reductions or GHG removal enhancements outside the organization or GHG project (GOST R ISO 14064-2021. National Standard of the Russian Federation. Greenhouse Gases. Part 1-3)

[8] Examples of GHG programs in Russia include GOST R ISO 14064-1-2021 (accounting and management of GHG emissions at the organization level), GOST R ISO 14064-2-2021 (accounting and management of GHG emissions at the project level), GOST R ISO 14067-2021 (carbon footprint of products); at the international level – the European Emissions Trading System (EU ETS), the Clean Development Mechanism (CDM), GHG Protocol for Corporate / Project / Products and for Scope 3 Accounting, Verified Carbon Standard (VCS), Gold Standard, etc.

[9] Power-only and heat-only project activities should not be accounted for under this methodology.

2.2. Applicability

5. The methodology is applicable under the following conditions:

   (a) The biomass used by the project plant is limited to biomass residues, biogas, RDF[10] and/or biomass from dedicated plantations.

   (b) Fossil fuels may be co-fired in the project plant. However, the amount of fossil fuels co-fired does not exceed 80% of the total fuel fired on energy basis.

   (c) For projects that use biomass residues from a production process (e.g. production of sugar or wood panel boards), the implementation of the project does not result in an increase of the processing capacity of the industrial facility generating the residues raw input (e.g. sugar, rice, logs, etc.) or in other substantial changes (e.g. product change) in this process.

   (d) The biomass used by the project plant is not stored for more than one year.

   (e) The biomass used by the project plant is not processed chemically or biologically (e.g. through esterification, fermentation, hydrolysis, pyrolysis, bio- or chemical-degradation, etc.) prior to combustion. Drying and mechanical processing, such as shredding and pelletization, are allowed.

6. In the case of fuel switch project activities, the use of biomass or the increase in the use of biomass as compared to the baseline scenario is technically not possible at the project site without a capital investment in:

   (a) the retrofit or replacement of the existing heat generators/boilers; or

   (b) the installation of new heat generators/boilers; or

   (c) a new dedicated supply chain of biomass established for the purpose of the project (e.g. collecting and cleaning contaminated new sources of biomass residues that could otherwise not be used for energy purposes); or

   (d) equipment for preparation and feeding of biomass.

7. If biogas is used for power and heat generation, the biogas must be generated by anaerobic digestion of wastewater, and:

   (a) if the wastewater generation source is registered as a project activity, the details of the wastewater project shall be included in the project design document (PDD), and emission reductions from biogas energy generation are claimed using this methodology;

   (b) if the wastewater source is not registered as a climate project, the amount of biogas does not exceed 50% of the total fuel fired on energy basis.

8. If biomass from dedicated plantations is used, Appendix 10 shall apply to determine the relevant project and leakage emissions from cultivation of biomass and from the utilization of biomass residues.

9. The methodology is not applicable if the baseline scenario involves the cultivation of biomass in dedicated plantations.

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[10] Refuse Derived Fuel (RDF) may be used in the project plant but all carbon in the fuel, including carbon from biogenic sources, shall be considered as fossil fuel.

10. In case of changes to the national legislation referred to herein, this methodology is subject to revision in order to take into account the relevant changes[11].

2.3. Project boundary

11. The spatial extent of the project boundary encompasses:

    (a) all plants generating power and/or heat located at the project site, whether fired with biomass, fossil fuels or a combination of both[12];

    (b) all power plants connected physically to the electricity system (grid) that the project plant is connected to;

    (c) if applicable, all off-site heat sources that supply heat to the site where the project activity is located (either directly or via a district heating system);

    (d) the means of transportation of biomass to the project site;

    (e) if the feedstock is biomass residues, the site where the biomass residues would have been left for decay or dumped;

    (f) if the feedstock is biomass produced in dedicated plantations, the geographic boundaries of the dedicated plantations;

    (g) the wastewater treatment facilities used to treat the wastewater produced from the treatment of biomass;

    (h) if biogas is included, the site of the anaerobic digester.

12. 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), the project documentation should include a description of procedures for eliminating the possibility of double counting[13] in GHG emission reductions potentially achieved as a result of project activities, enshrined in contractual agreements.

Table 2. Emission sources included in or excluded from the project boundary

Source		Gas	Included	Justification/Explanation
Baseline	Electricity and heat generation	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification. This is conservative
		N_2O	No	Excluded for simplification. This is conservative

[11] The project developer should keep in mind that the normative documents given in the text can be changed or cancelled.

[12] Note that the project boundary encompasses not only the plants generating power and/or heat that are directly affected by the project activity (e.g. retrofitted or installed) but also all other plants generating power and/or heat located at the same site as the project activity, whether fired with biomass, fossil fuels or a combination of both. Thus, power and heat generation, grid power and heat imports/exports should be considered for the whole site where the project activity is located and all facilities are to be included in the power and heat balances.

[13] 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.

Source		Gas	Included	Justification/Explanation
	Uncontrolled burning or decay of surplus biomass residues	CO_2	No	It is assumed that CO_2 emissions from surplus biomass residues do not lead to changes of carbon pools in the LULUCF sector
		CH_4	Yes or No	Project participants may decide to include this emission source, where case B1, B2 or B3 has been identified as the most likely baseline scenario
		N_2O	No	Excluded for simplification. This is conservative. Note also that emissions from natural decay of biomass are not included in GHG inventories as anthropogenic sources
Project activity	On-site fossil fuel consumption	CO_2	Yes	May be an important emission source
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small
	Off-site transportation of biomass	CO_2	Yes	May be an important emission source
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small
	Combustion of biomass for electricity and heat	CO_2	No	It is assumed that CO_2 emissions from surplus biomass do not lead to changes of carbon pools in the LULUCF sector
		CH_4	Yes or No	This emission source must be included if CH_4 emissions from uncontrolled burning or decay of biomass residues in the baseline scenario are included
		N_2O	No	Excluded for simplification. This emission source is assumed to be small
	Wastewater from the treatment of biomass	CO_2	No	It is assumed that CO_2 emissions from surplus biomass do not lead to changes of carbon pools in the LULUCF sector
		CH_4	Yes	This emission source shall be included in cases where the waste water is treated (partly) under anaerobic conditions
		N_2O	No	Excluded for simplification. This emission source is assumed to be small
	Cultivation of land to produce biomass feedstock	CO_2	Yes	This emission source shall be included in cases biomass from dedicated plantation is used
		CH_4	Yes	This emission source shall be included in cases biomass from dedicated plantation is used
		N_2O	Yes	This emission source shall be included in cases biomass from dedicated plantation is used

3. Baseline methodology

3.1. Identification of alternative scenarios

13. Project participants should identify all alternative scenarios in the absence of the project activity, including the project activity not being undertaken as a project activity, the continuation of the current situation and all plausible and relevant alternative scenarios.

The alternative scenarios shall specify:

(a) how electric power would be generated in the absence of the project activity (P scenarios);

(b) how heat would be generated in the absence of the project activity (H scenarios);

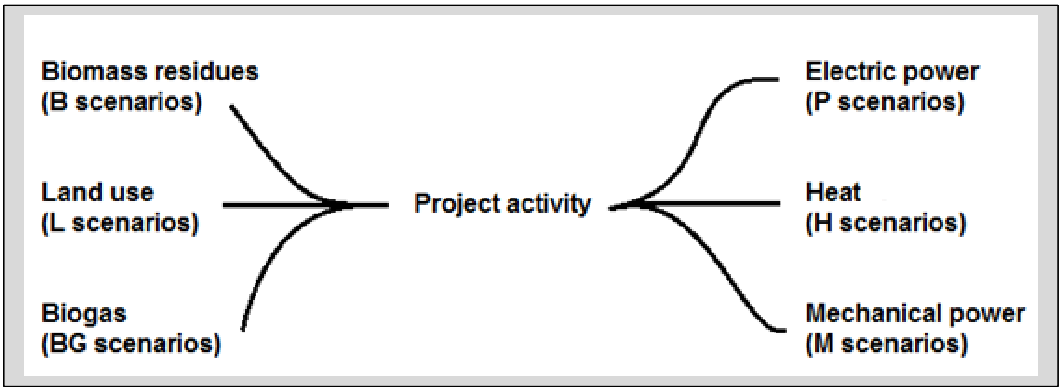
(c) if the project activity generates mechanical power through steam turbine(s): how the mechanical power would be generated in the absence of the project activity (M scenarios);

(d) if the project activity uses biomass residues, what would happen to the biomass residues in the absence of the project activity (B scenarios);

(e) if the project activity uses biomass cultivated in dedicated plantations, what the land use would be in the absence of the project activity (L scenarios); and

(f) if the project activity uses biogas from on-site wastewater, what would happen to the biogas in the absence of the project activity (BG scenarios).

Box 1. Selection of the baseline scenario



14. The alternative scenarios for electric power should include, but not be limited to the scenarios below, including the combination of relevant scenarios:

(a) P1: The proposed project activity not undertaken as a project activity.

(b) P2: If applicable[14], the continuation of power generation in existing power plants at the project site. The existing plants would operate at the same conditions (e.g. installed capacities, average load factors, or average energy efficiencies, fuel mixes, and equipment configuration) as those observed in the most recent three years prior to the starting date of the project activity.

(c) P3: If applicable (see footnote 12), the continuation of power generation in existing power plants at the project site. The existing plants would operate with different conditions from those observed in the most recent three years prior to the starting date of the project activity.

(d) P4: If applicable[15], the retrofitting of existing power plants at the project site. The retrofitting may or may not include a change in the fuel mix.

(e) P5: The installation of new power plants at the project site different from those installed under the project activity.

(f) P6: The generation of power in specific off-site plants, excluding the power grid.

(g) P7: The generation of power in the power grid.

[14] This alternative is only applicable if there are existing plants operating at the project site.

[15] This alternative is only applicable if there are existing plants operating at the project site.

15. The alternative scenarios for heat should include, but not be limited to, inter alia:

(a) H1: The proposed project activity not undertaken as a project activity.

(b) H2: If applicable (see footnote 14), the continuation of heat generation in existing plants at the project site. The existing plants would operate at the same conditions (e.g. installed capacities, average load factors, or average energy efficiencies, fuel mixes, and equipment configuration) as those observed in the most recent three years prior to the project activity.

(c) H3: If applicable (see footnote 14), the continuation of heat generation in existing plants at the project site. The existing plants would operate with different conditions from those observed in the most recent three years prior to the project activity.

(d) H4: If applicable (see footnote 14), the retrofitting of existing plants at the project site. The retrofitting may or may not include a change in the fuel mix.

(e) H5: The installation of new plants at the project site different from those installed under the project activity.

(f) H6: The generation of heat in specific off-site plants.

(g) H7: The use of heat from district heating.

16. The alternative scenarios for mechanical power should include, but not be limited to, inter alia:

(a) M1: The proposed project activity not undertaken as a project activity.

(b) M2: If applicable (see footnote 14), the continuation of mechanical power generation from the same steam turbines in existing plants at the project site.

(c) M3: The installation of new steam turbines at the project site.

(d) M4: If applicable (see footnote 14), the continuation of mechanical power generation from electrical motors in existing plants at the project site.

(e) M5: The installation of new electrical motors at the project site.

17. For any of the alternative scenarios described above, all assumptions with respect to installed capacities, load factors, energy efficiencies, fuel mixes, and equipment configuration, should be clearly described and justified in the PDD.

18. If existing plants are operated at the project site prior to the implementation of the project activity, the remaining lifetime of the existing equipment shall be determined as per Appendix 2. Determination of the remaining lifetime of equipment and a baseline based on historical performance only applies until the existing power plant would have been replaced or retrofitted in the absence of the project activity.

19. When using biomass residues, the alternative scenarios of the biomass residues use in the absence of the project activity shall be determined following Appendix 10.

20. In addition to the alternative scenarios (B scenarios) included in Appendix 10, the project participants shall include scenario B5:

(a) The biomass residues are used for power or heat generation at the project site in new and/or existing plants.

21. When using biomass cultivated in dedicated plantations, the project shall consider what the land use would be in the absence of the project activity (L scenario).

22. In case the proposed project activity includes the use of biogas, the project shall consider the following baseline alternatives for the biogas:

    (a) BG1: No biogas would be generated, and wastewater would not be treated by anaerobic digestion.

    (b) BG2: Biogas is captured and flared.

    (c) BG3: Biogas is captured and used to produce electricity and/or thermal energy.

    (d) BG4: Biogas is captured and used as feedstock or transportation fuel.

23. When defining plausible and credible alternative scenarios for the use of biogas, the guidance below should be followed:

    (a) If scenario BG1 and BG2 are selected, no biogas shall be included in the baseline scenario of the proposed project activity.

    (b) If scenario BG3 is selected, the same amount of biogas produced in the project shall be included in the baseline scenario.

    (c) In case the biogas is supplied by an existing project activity its reference shall be included in the PDD.

3.2. Baseline applicability

24. The methodology is only applicable if the baseline scenario is:

    (a) for power generation: scenarios P2 to P7, or a combination of any of those scenarios; and

    (b) for heat generation: scenarios H2 to H7, or a combination of any of those scenarios;

    (c) if some of the heat generated by the project activity is converted to mechanical power through steam turbines, for mechanical power generation: scenarios M2 to M5:

        (i) in cases M2 and M3, if steam turbine(s) are used for mechanical power in the project, the turbine(s) used in the baseline shall be at least as efficient as the steam turbine(s) used for mechanical power in the project;

        (ii) in cases M4 and M5, steam turbine(s) generating mechanical power to be used for the same purpose as in the baseline are not allowed;

    (d) for the use of biomass residues: scenarios B1 to B5, or a combination of any of those scenarios;

    (e) for the use of biogas: scenarios BG1 to BG3, or a combination of any of those scenarios.

3.3. Baseline emissions

25. In many cases, it may be difficult to clearly determine the precise mix of power generation in the grid and power or heat generation with biomass residues or fossil fuels that would have occurred in the absence of the project activity. For this reason, this methodology adopts a conservative

approach based on the following assumptions and taking into account any technical and operational constraints:

(a) Biomass residues, if available in the baseline scenario, would be used in the baseline as a priority for the generation of power and heat over the use of any fossil fuels.

(b) When different types of biomass result in different levels of heat generation efficiency, the allocation of biomass shall be guided to maximize the heat generation efficiency of the set of heat generators.

(c) If different types of fossil fuels can technically be used in the heat generators, the type of fossil fuel used should be guided by the principle that fossil fuels would be used so as to maximize the heat generation efficiency of the set of heat generators.

(d) Where heat can technically be generated in more than one heat generator, it should be assumed that it is generated from the most efficient to the less efficient heat generators to the maximum extent possible, taking into account any technical and operational constraints, including co-firing and the partial use of the heat generator in the previous steps.

(e) The heat provided by heat generators is used first in heat engines, which operate in cogeneration mode, then in thermal applications to satisfy the heat demand, and after that in heat engines, which operate for the generation of power only.

(f) Where heat can technically be used in more than one engine type, it should be allocated from the most efficient to the less efficient heat engines to the maximum extent possible.

(g) Where heat can technically be used in more than one cogeneration heat engine type, it should be assumed that it is allocated so as to maximize the cogeneration of process heat.

26. Project participants shall document and justify in the PDD in a transparent manner the allocation approach.

27. Baseline emissions are calculated as follows:

$$BE_y = EL_{BL,GR,y} \times EF_{EG,GR,y} + \sum_f FF_{BL,HG,y,f} \times EF_{FF,y,f} + EL_{BL,FF/GR,y} \times min\left(EF_{EG,GR,y}, EF_{EG,FF,y}\right) + BE_{BR,y}$$ Equation (1)

Where:

BE_y	=	Baseline emissions in year *y* (t CO_2)
$EL_{BL,GR,y}$	=	Baseline electricity sourced from the grid in year *y* (MWh)
$EF_{EG,GR,y}$	=	Grid emission factor in year *y* (t CO_2/MWh)
$FF_{BL,HG,y,f}$	=	Baseline fossil fuel demand for process heat in year *y* (GJ)
$EF_{FF,y,f}$	=	CO_2 emission factor for fossil fuel type *f* in year *y* (t CO_2/GJ)
$EL_{BL,FF/GR,y}$	=	Baseline uncertain electricity generation in the grid or on-site or off-site power-only units in year *y* (MWh)
$EF_{EG,FF,y}$	=	CO_2 emission factor for electricity generation at the project site or off-site plants in the baseline in year *y* (t CO_2/MWh)
$BE_{BR,y}$	=	Baseline emissions due to disposal of biomass residues in year *y* (t CO_2e)

f = Fossil fuel type

28. The procedure to determine baseline emissions can be summarized as follows:

(a) Step 1: Determine the total baseline process heat generation, electricity generation, capacity constraints, and efficiencies.

(b) Step 2: Determine the baseline electricity sourced from the grid and emission factors.

(c) Step 3: Determine the baseline biomass-based heat and power generation.

(d) Step 4: Determine the baseline demand for fossil fuels to meet the balance of process heat and the corresponding electricity generation.

(e) Step 5: Determine the baseline emissions due to uncontrolled burning or decay of biomass residues.

3.3.1. Step 1: Determine the total baseline process heat generation *($HC_{BL,y}$)*, electricity generation, capacity constraints, and efficiencies

3.3.1.1. Step 1.1: Determine the total baseline process heat generation

29. The amount of process heat that would be generated in the baseline in year *y* ($HC_{BL,y}$) is determined based on continuously monitored data of process heat generated in the project scenario[16] [17]. The process heat should be calculated net of any parasitic heat used for drying of biomass.

30. This methodology assumes for the sake of simplicity that the steam consumed in the baseline scenario would be the same quality as the steam used in the proposed project activity and transported through one steam header in both scenarios.[18]

3.3.1.2. Step 1.2: Determine the baseline capacity of electricity generation *($CAP_{EG,total,y}$)*

31. The total capacity of electricity generation available in the baseline is calculated as follows:

$$CAP_{EG,total,y} = LOC_y \times \left[\sum_i \left(CAP_{EG,CG,i} \times LFC_{EG,CG,i}\right) + \sum_j \left(CAP_{EG,PO,j} \times LFC_{EG,PO,j}\right)\right] \quad \text{Equation (2)}$$

Where:

$CAP_{EG,total,y}$ = Baseline electricity generation capacity in on-site and off-site plants in year y (MWh)

[16] Heat supplied during the project activity to a district heating system shall count as process heat and be included in the process heat.

[17] Heat supplied during the project activity to a mechanical steam turbine shall count as process heat and be included in the process heat

[18] If the baseline scenario involves steam headers with different steam enthalpies, the project participants shall assume the use of the header that ensures a conservative estimation of the baseline emissions.

$CAP_{EG,CG,i}$	=	Baseline electricity generation capacity of cogeneration-type heat engine *i* (MW)
$CAP_{EG,PO,j}$	=	Baseline electricity generation capacity of power-only-type heat engine *j* (MW)
$LFC_{EG,CG,i}$	=	Baseline load factor of cogeneration-type heat engine *i* (ratio)
$LFC_{EG,PO,j}$	=	Baseline load factor of power-only-type heat engine *j* (ratio)
LOC_y	=	Operation of the industrial facility using the process heat in year *y* (hour)
i	=	Cogeneration-type heat engine in the baseline scenario
j	=	Power-only-type heat engine in the baseline scenario

3.3.1.3. Step 1.3: Determine the efficiencies of heat generators, and efficiencies and heat-to-power ratio of heat engines

32. The efficiencies of heat generators ($\eta_{BL,HG,BR,h}/\eta_{BL,HG,FF,h}$) and heat engines ($\eta_{BL,EG,CG,i/j}/\eta_{BL,EG,PO,j}$) shall be calculated as per Appendix 11.

33. The heat-to-power ratio of cogeneration-type heat engines (e.g. backpressure and heat-extraction steam turbines) is calculated as follows:

(a) **Case 1:** For existing heat engines with a minimum three-year operational history prior to the project activity:

$$HPR_{BL,EG,CG,/PO,i/j} = \frac{1}{3.6} \times MAX\left\{\frac{HC_{BR,CG/PO,x,i/j}}{EL_{BR,CG/PO,x,i/j}};\frac{HC_{BR,CG/PO,x-1,i/j}}{EL_{BR,CG/PO,x-1,i/j}};\frac{HC_{BR,CG/PO,x-2,i/j}}{EL_{BR,CG/PO,x-2,i/j}}\right\} \quad \text{Equation (3)}$$

Where:

$HPR_{BL,i}$	=	Baseline heat-to-power ratio of the heat engine *i* (ratio)
$HC_{BR,CG/PO,x,i/j}$	=	Quantity of process heat extracted from the heat engine *i/j* in year *x* (GJ)
$EL_{BR,CG/PO,x,i/j}$	=	Quantity of electricity generated in heat engine *i/j* in year *x* (MWh)
x	=	Last calendar year prior to the start of the crediting period
i	=	Cogeneration-type heat engine in the baseline scenario
j	=	Power-only-type heat engine in the baseline scenario

(b) **Case 2:** For heat engines without a minimum three-year operational history prior to the project activity the heat-to-power ratio should be determined as per the design conditions of the plant, for the configuration identified as baseline scenario”.

3.3.2. Step 2: Determine the baseline electricity generation in the grid and emission factors

3.3.2.1. Step 2.1: Determine the baseline electricity generation *($EL_{BL,y}$)*

34. The amount of electricity that would be generated in the baseline in year *y* equals the amount of electricity generated in the project scenario as follows:

$$EL_{BL,y} = EL_{PJ,gross,y} + EL_{PJ,imp,y} - EL_{PJ,aux,y} \quad \text{Equation (4)}$$

Where:

$EL_{BL,y}$	=	Baseline electricity generation in year *y* (MWh)
$EL_{PJ,gross,y}$	=	Gross quantity of electricity generated in all power plants included in the project boundary in year *y* (MWh)
$EL_{PJ,imp,y}$	=	Project electricity imports from the grid in year *y* (MWh)
$EL_{PJ,aux,y}$	=	Total auxiliary electricity consumption required for the operation of the power plants in year *y* (MWh)

Box 2. Non-binding best practice example: Auxiliary electricity requirement

Project participants should account for the total auxiliary electricity consumption ($EL_{PJ,aux,y}$) required for the operation of the power plants at the project site. When appropriate, the total auxiliary electricity consumption may be estimated by considering the consumption capacity of all the installed equipment and assuming that they operated at maximum load during the monitoring period.

Example – A project activity involves the use of biomass residues to produce electricity and heat in an existing industrial facility. For the project activity, the project participants installed a biomass drier and a conveyor belt, and utilize auxiliary electricity for the actual operation of the power plant.

As a conservative approach, the project participants calculate the total auxiliary electricity consumption during year *y* as the sum of the capacities of all equipment items, times 8760 hours of operation per year (24 hours/day).

3.3.2.2. Step 2.2: Determine the baseline electricity sourced from the grid *($EG_{BL,GR,y}$)*

35. The amount of electricity that would be sourced from the grid in the baseline scenario is calculated assuming that the amount of electricity generated on-site and off-site in the baseline scenario shall be limited by the installed capacity of power generation available in the baseline scenario (on-site and off-site):

$$EL_{BL,GR,y} = \max\left(0, EL_{BL,y} - CAP_{EG,total,y}\right) \quad \text{Equation (5)}$$

Where:

$EL_{BL,GR,y}$	=	Baseline electricity sourced from the grid in year *y* (MWh)
$EL_{BL,y}$	=	Baseline electricity generation in year *y* (MWh)
$CAP_{EG,total,y}$	=	Baseline electricity generation capacity in on-site and off-site plants in year *y* (MWh)

36. For baseline alternatives not connected to the grid or otherwise technically or legally unable to import/export power from/to the grid, it shall be assumed that $EL_{BL,GR,y} = 0$.

3.3.2.3. Step 2.3: Determine the emission factor of grid electricity generation ($EF_{EG,GR,y}$)

37. The grid emission factor ($EF_{EG,GR,y}$) shall be determined using Appendix 6.

3.3.2.4. Step 2.4: Determine the emission factor of on-site electricity generation with fossil fuels ($EF_{EG,FF,y}$)

38. If no fossil fuel based power generation was identified as part of the baseline scenario, or if fossil fuel based power generation was identified as part of the baseline scenario, but all capacity of power generation based on fossil fuels is used in the cogeneration mode (i.e. up to step 4.2), then it should be assumed in equation (2) that $EF_{EG,FF,y} = EF_{EG,GR,y}$.

39. When fossil fuel based power only generation is identified as part of the baseline scenario and if fossil fuel power plants were operated at the project site prior to the implementation of the project activity, either Option A or Option B can be used to determine the emission factor ($EF_{EG,FF,y}$). For new power plants that would be constructed at the project site in the baseline scenario, Option B shall be used.

(a) **Option A:** Determine $EF_{EG,FF,y}$ as per the procedure described in Appendix 7, using data for the three calendar years prior to the date of submission of the PDD for validation of the project activity.

(b) **Option B:** Determine a default emission factor for $EF_{EG,FF}$ based on the efficiency of the power plant that would be operated at the project site in the baseline scenario and a default CO_2 emission factor for the fossil fuel types[19] that would be used, as follows:

$$EF_{EG,FF} = 3.6 \times \frac{EF_{BL,CO2,FF}}{\eta_{BL,FF}} \qquad \text{Equation (6)}$$

Where:

$EF_{EG,FF,y}$	=	CO_2 emission factor for electricity generation with fossil fuels at the project site in the baseline in year y (tCO_2/MWh)
$EF_{BL,CO2,FF}$	=	CO_2 emission factor of the fossil fuel type that would be used for power generation at the project site in the baseline (tCO_2/GJ)
$\eta_{BL,FF}$	=	Efficiency of the fossil fuel power plant(s) at the project site in the baseline (ratio)

3.3.3. Step 3: Determine the baseline biomass-based heat and power generation

3.3.3.1. Step 3.1: Determine the baseline biomass-based heat generation ($HG_{BL,BR,y}$)

40. It is assumed that the use of biomass residues for which scenario B5 has been identified as the baseline scenario ($BR_{B5,n,y}$) would be prioritized over the use of any fossil fuels in the baseline.

[19] In the situation where there are several plants using different fossil fuels, the emission factor shall be determined ensuring a conservative estimation of baseline emissions.

Assuming that the equivalent amount of heat that would be generated with biomass residues ($HG_{BL,BR,y}$) shall be determined as follows[20]:

$$HG_{BL,BR,y} = \sum_h \sum_n \left(BR_{B5,n,h,y} \times NCV_{BR,n,y} \times \eta_{BL,HG,BR,h}\right) \qquad \text{Equation (7)}$$

Where:

$HG_{BL,BR,y}$	=	Baseline biomass-based heat generation in year *y* (GJ)
$BR_{B5,n,h,y}$	=	Quantity of biomass residues of category *n* used in heat generator *h* in year *y* with baseline scenario B5 (ton on dry basis)
$NCV_{BR,n,y}$	=	Net calorific value of biomass residue of category *n* in year *y* (GJ/ton on dry basis)
$\eta_{BL,HG,BR,h}$	=	Baseline biomass-based heat generation efficiency of heat generator *h* (ratio)

41. The allocation of biomass residues to the different heat generators ($BR_{B5,n,h,y}$) shall be guided so as to maximize the heat generation efficiency of the set of heat generators, taking into account the following:

(a) Where only one category of biomass residues would be used in the baseline in clearly identifiable baseline heat generators, the monitored quantities of biomass residues used in the project can be directly allocated to those baseline heat generators.

(b) Where one category of biomass residue from one particular source could be used in the baseline in two or more heat generators with different efficiencies, the project participants shall specify in a transparent manner how the respective amounts of biomass residues are allocated to each of the heat generators.

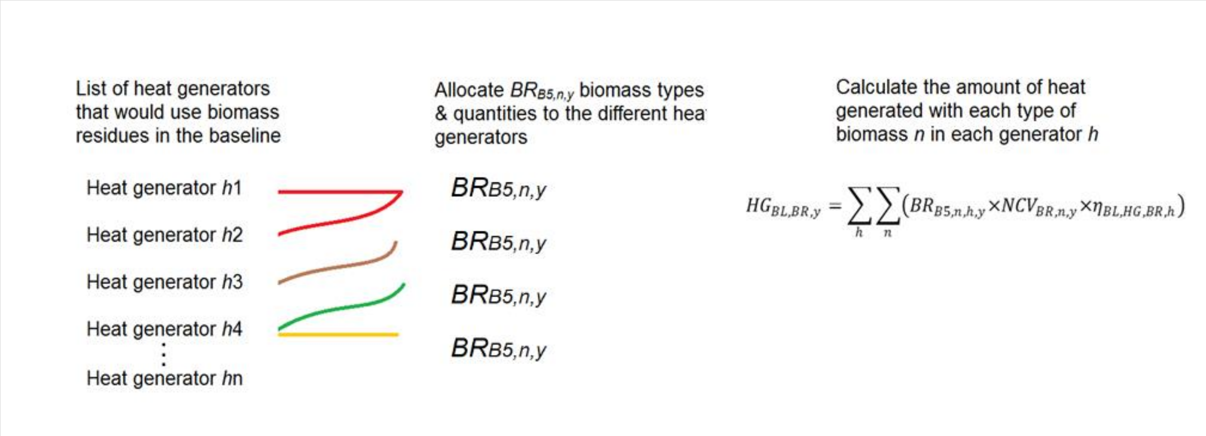
(c) Where one category of biomass residue can technically be used in heat generators, which do not require co-firing with fossil fuels, as well as heat generators, which require co-firing with fossil fuels, it should be assumed that the biomass is used to the maximum extent possible in the heat generator, which does not require co-firing with fossil fuels, taking into account any technical and operational constraints. Any remaining biomass residue quantities are then allocated to the subsequent heat generators, which require co-firing with fossil fuels.

(d) Where biomass residues could be used for power generation at the project site (B5), the respective amounts shall be determined based on the largest amounts of that category of biomass used for power and/or heat generation in the most recent three calendar years prior to the date of submission of the PDD for validation of the project activity.

[20] The biomass residues used in each heat generator ($BR_{B5,n,h,y}$) shall not exceed the total amount of biomass residues available, and the heat generation in each heat generator should not exceed the total capacity of the heat generator.

Box 3. Non-binding best practice example: Baseline biomass-based heat generation (step 3.1)

This methodology assumes that the use of biomass residues ($BR_{B5,n,y}$) would be prioritized over the use of any fossil fuels in the baseline. The equivalent amount of heat that would be generated with biomass residues ($HG_{BL,BR,y}$) should be determined based on the allocation of the quantities of each type of biomass to the different generators.



3.3.3.2. Step 3.2: Determine the baseline biomass-based cogeneration of process heat and electricity and heat extraction

42. It is assumed that cogeneration of process heat and power using biomass-based heat ($HG_{BL,BR,y}$) would be prioritized over other uses of this biomass-based heat as well as over the use of fossil fuels for the generation of process heat and power on-site. With that assumption the equivalent amount of electricity ($EL_{BL,BR,CG,y}$) and process heat ($HC_{BL,BR,CG,y}$) that would be generated from biomass-based heat ($HG_{BL,BR,y}$) are determined as follows: [21]

~~43.~~ Calculate

$$EL_{BL,BR,CG,y} = \frac{1}{3.6} \times \sum_i \left(\frac{1}{(HPR_{BL,i} + 1)} \times \eta_{BL,EG,CG,i} \times HG_{BL,BR,CG,y,i} \right) \quad \text{Equation (8)}$$

$$HC_{BL,BR,CG,y} = \sum_i \left(\frac{HPR_{BL,i}}{(HPR_{BL,i} + 1)} \times \eta_{BL,EG,CG,i} \times HG_{BL,BR,CG,y,i} \right) \quad \text{Equation (9)}$$

Where:

$EL_{BL,BR,CG,y}$	=	Baseline biomass-based cogenerated electricity in year *y* (MWh)
$\eta_{BL,EG,CG,i}$	=	Baseline electricity generation efficiency of heat engine *i* (MWh/GJ)
$HG_{BL,BR,CG,y,i}$	=	Baseline biomass-based heat used in heat engine *i* in year *y* (GJ)
$HC_{BL,BR,CG,y}$	=	Baseline biomass-based process heat cogenerated in year *y* (GJ)
$HPR_{BL,i}$	=	Baseline heat-to-power ratio of heat engine *i* (ratio)

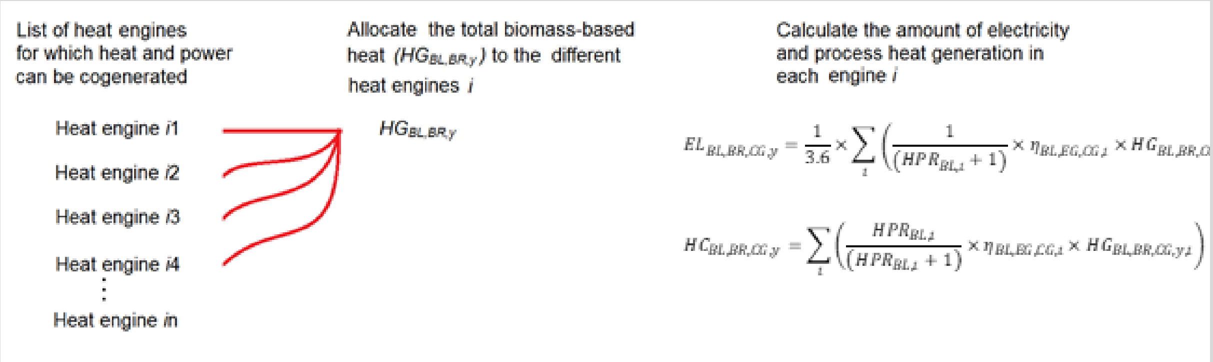
44. The total biomass-based heat ($HG_{BL,BR,y}$) shall be allocated to the different heat engines ($HG_{BL,BR,CG,y,i}$) so as to maximize the cogeneration of process heat. For instance, in case of steam

[21] The biomass-based heat used in cogeneration mode ($HG_{BL,BR,CG,y,i}$) should not exceed the total biomass-based heat generated and the electricity generation in each heat engine should not exceed the total capacity of the heat engine.

cycles, if both back-pressure and heat-extraction steam turbines are identified in the baseline, heat should be first allocated to back-pressure turbines and then to heat-extraction turbines to the maximum extent possible, taking into account any technical and operational constraints.

Box 4. Non-binding best practice example: Baseline biomass-based cogeneration (step 3.2)

This methodology assumes that cogeneration of process heat and power using biomass-based heat ($HG_{BL,BR,y}$) would be prioritized over the use of fossil fuels. The equivalent amount of electricity ($EL_{BL,BR,CG,y}$) and process heat ($HC_{BL,BR,CG,y}$) that would be generated are determined based on the allocation of biomass-based heat to the different engines *i*.



45. The next step to be followed depends on the outcomes of the calculations above. The following cases are possible:

(a) Cases 3.2.1: all the heat that would be generated using biomass residues in the baseline would be used in cogeneration-type heat engines:

(i) Case 3.2.1.1: all the heat that would be generated using biomass residues in the baseline would be used in cogeneration-type heat engines and would match all process heat demand;

(ii) Case 3.2.1.2: all the heat that would be generated using biomass residues in the baseline would be used in cogeneration-type heat engines, but still some process heat demand would remain to be met using fossil fuel;

(b) Case 3.2.2: excess biomass-based heat would be available after meeting the baseline process heat demand with biomass-based heat sourced from co-generation units, and used for generation of power in power-only mode;

(c) Cases 3.2.3: biomass-based heat exceeds or equals the demand of cogeneration-type heat engines:

(i) Case 3.2.3.1: The biomass-based heat equals the remaining demand for process heat. Then, there is no more biomass-based heat available and the demand for process heat has been met.

(ii) Case 3.2.3.2: Excess biomass-based heat is less than the remaining demand for process heat. Then, all biomass-based heat is used and there still remains process heat demand to be met using fossil fuels.

(iii) Case 3.2.3.3: Excess biomass-based heat is greater than the remaining demand for process heat, and there remains some biomass-based heat to be used in power-only generation units after the demand for process heat was met.

46. Case 3.2.1.1: $HG_{BL,BR,y} = \sum_i HG_{BL,BR,CG,y,i}$ and $HC_{BL,y} = HC_{BL,BR,CG,y}$ If all the heat that would be generated using biomass residues in the baseline would be used in cogeneration-type heat engines and would match the demand for process heat, it is assumed that the use of fossil fuels on-site and off-site in the baseline scenario would be uncertain (except for the amount required due to technical constraints) because it would depend on a number of factors that are not taken into account in this methodology.

47. Based on these assumptions:

(a) $EL_{BL,FF/GRy} = EL_{BL,y} - EL_{BL,GR,y} - EL_{BL,BR,CG,y}$,

(b) $EL_{PJ,offset,y}$ = 0, and

(c) $EL_{BL,HG,y,f}$ = 0

Where:

$EL_{BL,FF/GR,y}$	=	Baseline uncertain electricity sourced from the grid or on-site or off-site power-only units in year *y* (MWh)[22]
$EL_{PJ,offset,y}$	=	Electricity that would be generated in the baseline that exceeds the generation of electricity during year y (MWh)
$EL_{BL,HG,y,f}$	=	Baseline electricity generation using fossil fuel *f* in year *y* (MWh)
f	=	Fossil fuel type

48. Then, project participants may proceed to Step 5: Determine the baseline emissions due to uncontrolled burning or decay of biomass residues.

49. Case 3.2.1.2: $HG_{BL,BR,y} = \sum_i HG_{BL,BR,CG,y,i}$ and $HC_{BL,y} > HC_{BL,BR,CG,y}$ If all the heat that would be generated using biomass residues in the baseline would be used in cogeneration-type heat engines but still some process heat demand would remain to be met, it is assumed that the remaining process heat balance is met with fossil fuels.

50. Under these assumptions:

(a) $HC_{balance,FF,y} = HC_{BL,y} - HC_{BL,BR,CG}$, and

(b) $EL_{balance,FF,y} = EL_{BL,y} - EL_{BL,GR,y} - EL_{BL,BR,CG,y}$,

Where:

$HC_{balance,FFy}$	=	Process heat balance demand after cogeneration in year *y* (GJ)
$EL_{balance,FF,y}$	=	Balance of electricity generated with fossil fuels in year *y* (MWh)

51. Then, project participants should proceed to Step 4: Determine the baseline demand for fossil fuels to meet the balance of process heat and the corresponding electricity generation.

52. Case 3.2.2: $HG_{BL,BR,y} > \sum_i HG_{BL,BR,CG,y,i}$ and $HC_{BL,y} = HC_{BL,BR,CG,y}$ If all process heat demand would be met with biomass-based heat in the baseline and still there would be some biomass-based

[22] Please refer to Equation 1.

heat to be used, it is assumed that this heat would be used for generation of power in power-only mode, i.e. without cogeneration of process heat.

53. Project participants shall define:

(a) $HG_{balance,BR,PO,y} = HG_{BL,BR,y} - \sum_i HG_{BL,BR,CG,y,i}$, and

(b) $EL_{balance,PO,y} = EL_{BL,y} - EL_{BL,GR,y} - EL_{BL,BR,CG,y}$

Where:

$HG_{balance,BR,POy}$	=	Balance of heat produced using biomass residues used in power-only mode in year *y* (GJ)
$EL_{balance,PO,y}$	=	Balance of electricity generated in power-only mode in year *y* (MWh)

54. Then, project participants should proceed to Step 3.3: Determine the baseline biomass-based electricity generated in power-only mode.

55. Case 3.2.3: $HG_{BL,BR,y} > \sum_i HG_{BL,BR,CG,y,i}$ and $HC_{BL,y} \geq HC_{BL,BR,CG,y}$. If there would be biomass-based heat in the baseline that could still be used and process heat demand to be met, it is assumed that this balance of biomass-based heat would be extracted from the heat header and used to meet the process heat demand without cogeneration of power. Three cases should thus be considered.

56. Case 3.2.3.1: $HC_{BL,y} - HC_{BL,BR,CG,y} = \frac{h_{LOW,y}}{h_{HIGH,y}} \times \left(HG_{BL,BR,y} - \sum_i HG_{BL,BR,CG,y,i}\right)$. If the balance of biomass-based heat (right-hand side of the equation) equals the remaining demand for process heat (left-hand side of the equation), then there is no more biomass-based heat available and the demand for process heat has been met. It is assumed then that the use of fossil fuels on-site would be uncertain in the baseline scenario (except for the amount required due to technical constraints) because it would depend on a number of factors that are not taken into account in this methodology.

57. Under these assumptions:

(a) $EL_{BL,FF/GR,y} = EL_{BL,y} - EL_{BL,GR,y} - EL_{BL,BR,CG,y}$, and

(b) $EL_{PJ,offset,y} = 0$, and

(c) $FF_{BL,HG,y,f} = 0$

Where:

$EL_{BL,FF/GR,y}$	=	Baseline uncertain electricity sourced from the grid or on-site or off-site power-only units in year *y* (MWh)
$EL_{PJ,offset,y}$	=	Electricity that would be generated in the baseline that exceeds the generation of electricity during year *y* (MWh)
$FF_{BL,HGy,f}$	=	Baseline fossil fuel demand for process heat in year *y* (GJ)
$h_{LOW,y}$	=	Specific enthalpy of the heat carrier at the process heat demand side (GJ/ton)
$h_{HIGH,y}$	=	Specific enthalpy of the heat carrier at the heat generator side (GJ/ton)

58. Then, project participants should proceed to Step 5: Determine the baseline emissions due to uncontrolled burning or decay of biomass residues.

59. Case 3.2.3.2: $HC_{BL,y} - HC_{BL,BR,CG,y} > \frac{h_{LOW,y}}{h_{HIGH,y}} \times \left(HG_{BL,BR,y} - \sum_i HG_{BL,BR,CG,y,i}\right)$. If the balance of biomass-based heat (right-hand side of the equation) is less than the remaining demand for process heat (left-hand side of the equation), all biomass-based heat was used and there still remains process heat demand to be met. It is assumed then that this process heat demand would be met by using fossil fuels in the baseline.

60. Under these assumptions:

(a) $$HC_{balance,FF,y} = \left(HC_{BL,y} - HC_{BL,BR,CG,y}\right) - \frac{h_{LOW}}{h_{HIGH}} \times \left(HG_{BL,BR,y} - \sum_i HG_{BL,BR,CG,y,i}\right)$$

and

(b) $$EL_{balance,FF,y} = EL_{BL,y} - EL_{BL,GR,y} - EL_{BL,BR,CG,y}$$

Where:

$HC_{balance,FFy}$	=	Process heat balance demand after cogeneration in year *y* (GJ)
$EL_{balance,FF,y}$	=	Balance of electricity generated with fossil fuels in year *y* (MWh)

61. Then, project participants should proceed to Step 4: Determine the baseline demand for fossil fuels to meet the balance of process heat and the corresponding electricity generation.

62. Case 3.2.3.3: $HC_{BL,y} - HC_{BL,BR,CG,y} < \frac{h_{LOW}}{h_{HIGH}} \times \left(HG_{BL,BR,y} - \sum_i HG_{BL,BR,CG,y,i}\right)$. If the balance of biomass-based heat (right-hand side of the equation) is greater than the remaining demand for process heat (left-hand side of the equation), there remains some biomass-based heat to be used after the demand for process heat was met. It is assumed then that this heat would be used to generate electricity in power-only mode, i.e. without cogeneration of process heat.

63. Under these assumptions:

(a) $$HG_{balance,BR,PO,y} = \left(HG_{BL,BL,y} - \sum_i HG_{BL,BR,CG,y,i}\right) - \frac{h_{HIGH}}{h_{LOW}} \times \left(HC_{BL,y} - HC_{BL,BR,CG,y}\right)$$, and

(b) $$EL_{balance,PO,y} = EL_{BL,y} - EL_{BL,GR,y} - EL_{BL,BR,CG,y}$$

Where:

$HG_{BL,BR,PO,y,j}$	=	Baseline biomass-based heat used in heat engine *j* in year *y* (GJ)
$HC_{BL,BR,CG,y}$	=	Baseline biomass-based process heat cogenerated in year *y* (GJ)
$EL_{balance,PO,y}$	=	Balance of electricity generated in power-only in year *y* (MWh)

64. Then, project participants should proceed to Step 3.3: Determine the baseline biomass-based electricity generated in power-only mode.

3.3.3.3. Step 3.3: Determine the baseline biomass-based electricity generated in power-only mode

65. If power-only-type heat engines have been identified in the baseline scenario, it is assumed that the balance of heat produced using biomass residues, if any, would be used in power-only mode.

66. The amount of biomass-based electricity generated in power-only mode in the baseline[23] is calculated as follows:

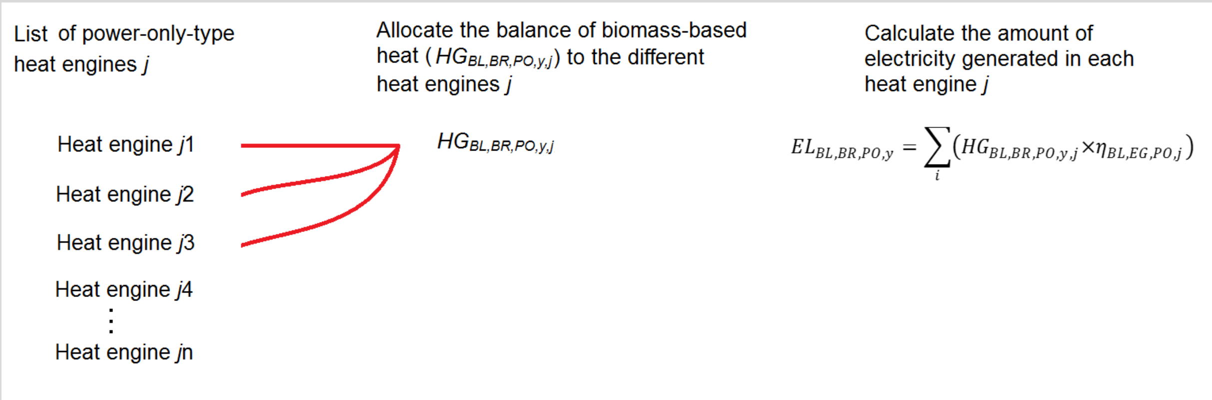
$$EL_{BL,BR,PO,y} = \sum_{i}(HG_{BL,BR,PO,y,j} \times \eta_{BL,EG,PO,j}) \qquad \text{Equation (10)}$$

Where:

$EL_{BL,BR,PO,y}$	=	Baseline biomass-based electricity (power-only) in year *y* (MWh)
$HG_{BL,BR,PO,y,j}$	=	Baseline biomass-based heat used in heat engine *j* in year *y* (GJ)
$\eta_{BL,EG,PO,j}$	=	Average electric power generation efficiency of heat engine *j* (MWh/GJ)

Box 5. Non-binding best practice example: Baseline biomass-based power-only (step 3.3)

This methodology assumes that if power-only-type heat engines have been identified in the baseline scenario, the balance of heat produced using biomass residues, if any, would be used in power-only mode. The baseline biomass-based electricity in power-only ($EL_{BL,BR,PO,y,j}$) is determined based on the allocation of the balance of biomass-based heat to the different engines *i*.



67. The following cases are possible depending on the results of the calculations above:

(a) Case 3.3.1: the amount of electricity generated on-site in the baseline is either equal to or less than the amount of electricity generated in the project scenario;

(b) Case 3.3.2: the amount of electricity generated on-site in the baseline is larger than the amount of electricity generated in the project scenario, and grid-export was available in the baseline.

68. Case 3.3.1: If $EL_{balance,PO,y} \geq EL_{BL,BR,PO,y}$, the amount of electricity generated on-site in the baseline is either equal to or less than the amount of electricity generated in the project scenario, the project participants shall define:

(a) $EL_{BL,FF/GR,y} = EL_{balance,PO,y} - EL_{BL,BR,PO,y}$,

(b) $EL_{PJ,offset,y} = 0$, and

[23] The biomass-based heat used in the heat engines should not exceed the biomass-based heat balance and the electricity generation in each heat engine should not exceed the total capacity of the heat engine.

(c) $FF_{BL,HG,y,f} = 0$

Where:

$EL_{BL,FF/GR,y}$	=	Baseline uncertain electricity sourced from the grid or on-site or off-site power-only units in year *y* (MWh)
$EL_{PJ,offset,y}$	=	Electricity that would be generated in the baseline that exceeds the generation of electricity during year *y* (MWh)
$FF_{BL,HGy,f}$	=	Baseline fossil fuel demand for process heat in year *y* (GJ).

69. Then, project participants should proceed to Step 5: Determine the baseline emissions due to uncontrolled burning or decay of biomass residues.

70. Case 3.3.2: If $EL_{balance,PO,y} < EL_{BL,BR,PO,y}$, the amount of electricity generated on-site in the baseline is larger than the amount of electricity generated in the project scenario, and if grid-export was available in the baseline, this result indicates that the project activity results in a decrease of power output which is likely to be supplied by the grid.[24] As a consequence, project emissions in the form of generation of electricity in the grid should be accounted as $EL_{PJ,offset,y}$. Under these assumptions:

(a) $EL_{BL,FF/GR,y} = 0$,

(b) $EL_{PJ,offset,y} = EL_{BL,BR,PO,y} - EL_{balance,PO,y}$, and

(c) $FF_{BL,HG,y,f} = 0$

Where:

$EL_{BL,FF/GR,y}$	=	Baseline uncertain electricity sourced from the grid or on-site or off-site power-only units in year *y* (MWh)
$EL_{PJ,offset,y}$	=	Electricity that would be generated in the baseline that exceeds the generation of electricity during year *y* (MWh)
$FF_{BL,HGy,f}$	=	Baseline fossil fuel demand for process heat in year *y* (GJ)

71. Then, project participants may proceed to Step 5: Determine the baseline emissions due to uncontrolled burning or decay of biomass residues.

3.3.4. Step 4: Determine the baseline demand for fossil fuels to meet the balance of process heat and the corresponding electricity generation

3.3.4.1. Step 4.1: Determine the baseline fossil fuel-based cogeneration of process heat and electricity, and the remaining process heat demand

72. When the amount of biomass residues available is not sufficient to generate the heat required to meet the process heat demand[25], it is assumed that the balance of process heat is met using fossil fuels, resulting in related fossil fuel baseline emissions. Where fossil fuel-based cogeneration, capacity is available it is assumed that the remaining process heat demand will first be supplied by cogeneration and then by direct use of heat supplied by heat generators.

[24] This situation should not be expected, as eligible project activities under this methodology should lead to using biomass more efficiently, which should result in surplus of power generation when compared to the baseline scenario.

[25] Cases 3.2.2 and 3.2.4.3 above.

73. The amount of cogenerated electricity and the amount of heat that would need to be generated with fossil fuels in heat generators in order to supply the cogeneration heat engine i, shall be calculated as follows[26]:

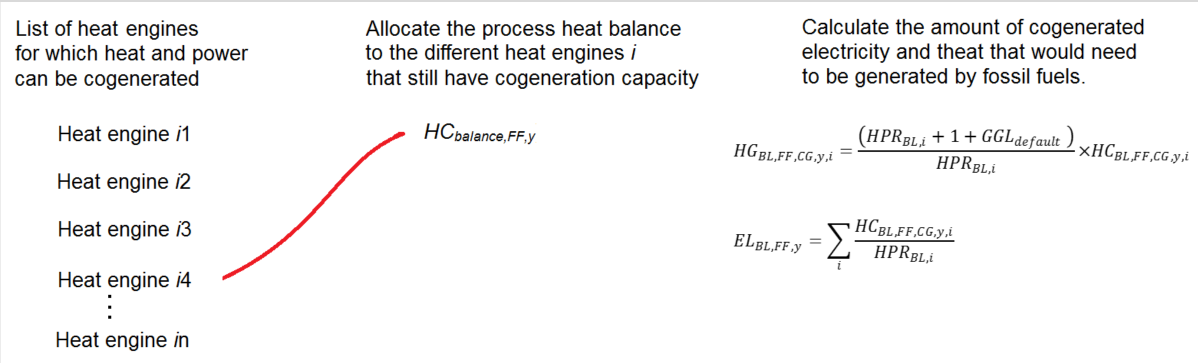
$$HG_{BL,FF,CG,y,i} = \frac{(HPR_{BL,i} + 1 + GGL_{default})}{HPR_{BL,i}} \times HC_{BL,FF,CG,y,i} \qquad \text{Equation (11)}$$

Where:

$HG_{BL,FF,CG,y,i}$	=	Baseline fossil-based heat used in heat engine *i* in year *y* (GJ)
$HC_{BL,CG,FF,y}$	=	Baseline fossil-based process heat cogenerated in year *y* (GJ)
$GGL_{default}$	=	The default value for the losses linked to the electricity generator group (turbine, couplings and electricity generator) (Default value of 0.05) (ratio)
$HPR_{BL,i}$	=	Baseline heat-to-power ratio of heat engine *i* (ratio)

Box 6. Non-binding best practice example 6: Baseline fossil fuel-based cogeneration (step 4.1)

This methodology assumes that in many cases, the amount of biomass residues available is not enough to generate the heat required to meet the process heat demand. In such cases, and if fossil-fuel-based heat generators have been identified in the baseline scenario, it is assumed that the balance of process heat is met using fossil fuels. The amount of cogenerated electricity and heat that would need to be generated by fossil fuels are determined based on the allocation of the heat balance to the different engines *i*.



74. When after step 4.1 $HC_{balance,FF,y} > HC_{BL,FF,CG,y}$ there would still be process heat demand to be met, it is assumed that this balance of process heat would be generated with fossil fuels and extracted from the heat header, and used to meet the process heat demand without cogeneration of power until all baseline process heat is met.

$$HG_{BL,FF,DHE,y} = (HC_{balance,FF,y} - HC_{BL,FF,CG,y}) \times \frac{h_{HIGH,y}}{h_{LOW,y}} \qquad \text{Equation (12)}$$

$$HG_{BL,FF,y} = HG_{BL,FF,CG,y} + HG_{BL,FF,DHE,y} \qquad \text{Equation (13)}$$

[26] The fossil fuel based cogenerated process heat ($HC_{BL,FF,CG,y,i}$) should not exceed the balance of process heat demand ($HC_{balance,FF,y}$).

Where:

$HC_{balance,FF,y}$	=	Balance of process heat demand after cogeneration in year *y* (GJ)
$HC_{BL,FF,CG,y}$	=	Baseline fossil fuel based process heat cogenerated in year *y* (GJ)
$h_{LOW,y}$	=	Specific enthalpy of the heat carrier at the process heat demand side (GJ/ton)
$h_{HIGH,y}$	=	Specific enthalpy of the heat carrier at the heat generator side (GJ/ton)
$HG_{BL,FF,y}$	=	Baseline fossil fuel based heat generation in year *y* (GJ)
$HG_{BL,FF,DHE,y}$	=	Baseline fossil fuel based heat used to meet baseline process heat demand via direct heat extraction in year *y* (GJ)
$HG_{BL,FF,CG,y}$	=	Baseline fossil fuel based heat cogeneration in year *y* (GJ)

75. The following cases are possible depending on the results of the calculations above:

(a) Case 4.1.1: the amount of electricity generated on-site in the baseline is either equal to or less than the amount of electricity generated in the project scenario;

(b) Case 4.1.2: the amount of electricity generated on-site in the baseline exceeds the amount of electricity generated in the project scenario and grid export was available in the baseline.

76. Case 4.1.1: $EL_{balance,FF,y} \geq EL_{BL,FF,y}$: The amount of electricity generated on-site in the baseline is either equal to or less than the amount of electricity generated in the project scenario. In order to determine the resulting baseline emissions, project participants should define:

(a) $EL_{BL,FF/GR,y} = EL_{balance,FF,y} - EL_{BL,FF,y}$, *and*

77. $EL_{PJ,offset,y} = 0$, then project participants should proceed to Step 4.2.

78. Case 4.1.2: $EL_{balance,FF,y} < EL_{BL,FF,y}$The amount of electricity generated on-site in the baseline exceeds the amount of electricity generated in the project scenario. If grid export was available in the baseline, this result indicates that the project activity results in a decrease of power output which is likely to be supplied by the grid. As a consequence, project emissions in the form of generation of electricity in the grid should be accounted for via the parameter $EL_{PJ,offset,y}$.

79. Project participants shall define:

(a) $EL_{BL,FF/GR,y} = 0$, and

(b) $EL_{PJ,offset,y} = EL_{BL,FF,y} - EL_{balance,FF,y}$

Then, project participants should proceed to Step 4.2.

3.3.4.2. Step 4.2: Determine the baseline heat generation to meet the fossil fuel based cogeneration of heat and power, and the heat to meet the balance of process heat

80. Estimate the total amount of fossil fuel required to generate the heat required for the cogeneration[27] in Step 4.1 and the balance of process heat as follows:

$$\sum_{h} HG_{BL,FF,y,h} = HG_{BL,FF,DHE,y} + HG_{BL,FF,CG,y}$$ Equation (14)

$$FF_{BL,HG,y,f} = \sum_{h} \left(\frac{HG_{BL,FF,y,h}}{\eta_{BL,HG,FF,h}} \right)$$ Equation (15)

Where:

$FF_{BL,HG,y,f}$	=	Baseline fossil fuel demand for process heat in year *y* (GJ)
$HG_{BL,FF,y,h}$	=	Baseline fossil fuel based heat generation in heat generator *h* in year *y* (GJ)
$\eta_{BL,HG,FF,h}$	=	Baseline fossil fuel based heat generation efficiency of heat generator *h* (ratio)[28]
$HG_{BL,FF,DHE,y}$	=	Baseline fossil fuel based heat used to meet the baseline process heat demand via direct heat extraction in year *y* (GJ)
$HG_{BL,FF,CG,y}$	=	Baseline fossil fuel based heat cogeneration in year *y* (GJ)

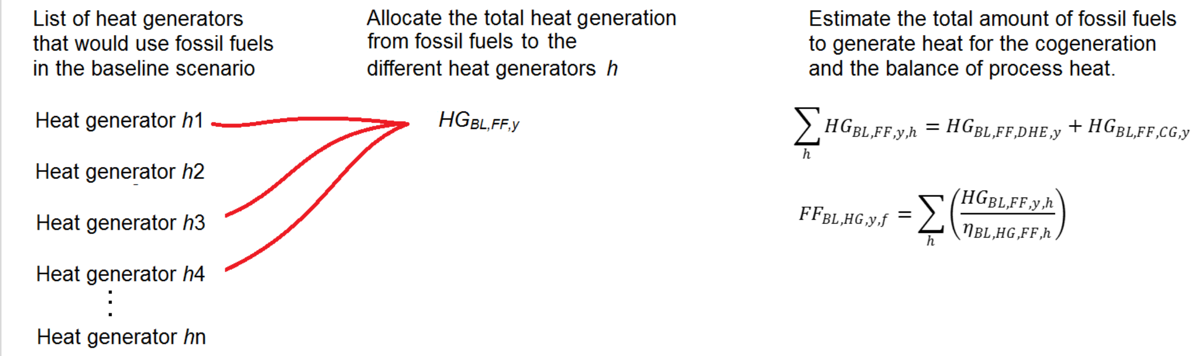
81. The total heat generation from fossil fuels ($HG_{BL,FF,y}$) shall be allocated to different heat generators ($HG_{BL,FF,y,h}$), so as to maximize the heat generation efficiency, subject to the difference in heat content in the different heat carriers, up to the level required for meeting the balance of process heat demand.

[27] The heat generation in each heat generator ($HG_{BL,FF,y,h}$) should not exceed the total capacity of the heat generator.

[28] In case of connection to a district heating system or off-site heat supply from which the individual sources cannot be identified, the district heating system shall be considered the most efficient heat source. The capacity of the district heating system shall be considered unlimited unless it can be justified (based on historical consumption data or heat purchase contracts) that the amount of heat to be consumed from/ or delivered to the district heat system was limited. The emission factor of the district heating system shall be considered 0.

Box 7. Non-binding best practice example: Baseline heat generation to meet the fossil-based cogeneration (step 4.2)

This methodology considers that several heat generators might be identified as part of the baseline scenario. In such cases, the total heat generation required from fossil fuels is allocated to the different heat generators *h* in order to determine the total amount of fossil fuels required to generate the heat required for the cogeneration and the balance of process heat.



3.3.5. Step 5: Determine the baseline emissions due to uncontrolled burning or decay of biomass residues

82. The calculation of baseline emissions due to uncontrolled burning or decay of biomass residues is optional and project participants can decide whether to include these emission sources or not. If project participants wish to include these emission sources, the procedure below should be followed, and emissions from combustion of biomass residues under the project activity should also be determined. Otherwise, this section does not need to be applied and project emissions do not need to include emissions from the combustion of biomass residues under the project activity.

83. Baseline emissions due to uncontrolled burning or decay of biomass residues are only determined for those categories of biomass residues for which B1, B2 or B3 has been identified as the baseline scenario.

84. Emissions are determined separately for biomass residues categories for which scenarios B1 and B3 (aerobic decay or uncontrolled burning) apply, and for biomass residues categories for which scenario B2 (anaerobic decay) applies:

$$BE_{BR,y} = BE_{BR,B1/B3,y} + BE_{BR,B2,y} \qquad \text{Equation (16)}$$

Where:

$BE_{BR,y}$	=	Baseline emissions due to disposal of biomass residues in year *y* (t CO2e)
$BE_{BR,B1/B3y}$	=	Baseline emissions due to aerobic decay or uncontrolled burning of biomass residues in year *y* (t CO_2)
$BE_{BR,B2,y}$	=	Baseline emissions due to anaerobic decay of biomass residues in year *y* (t CO_2)

3.3.5.1. Step 5.1: Determine $BE_{BR,B1/B3,y}$

85. For the biomass residues categories for which the most likely baseline scenario is either that the biomass residues would be dumped or left to decay under mainly aerobic conditions (B1), or burnt in an uncontrolled manner without utilizing them for energy purposes (B3), baseline emissions are

calculated assuming, for both scenarios (aerobic decay and uncontrolled burning), that the biomass residues would be burnt in an uncontrolled manner.

86. Baseline emissions are calculated as follows:

$$BE_{BR,B1/B3,y} = GWP_{CH4} \times \sum_{n} BR_{B1/B3,n,y} \times NCV_{BR,n,y} \times EF_{BR,n,y} \quad \text{Equation (17)}$$

Where:

$BE_{BR,B1/B3y}$	=	Baseline emissions due to aerobic decay or uncontrolled burning of biomass residues in year *y* (t CO_2)
GWP_{CH4}	=	Global Warming Potential of methane valid for the commitment period (tCO_2/t CH_4)
$BR_{BR,B1/B3,n,y}$	=	Quantity of biomass residues of category *n* used in the project activity in year *y* for which the baseline scenario is B1 or B3 (tons on dry basis)
$NCV_{BR,n,y}$	=	Net calorific value of biomass residue of category *n* in year *y* (GJ/ton on dry basis)
$EF_{BR,n,y}$	=	CH_4 emission factor for uncontrolled burning of category *n* biomass residues during year *y* (tCH_4/GJ)
n	=	Biomass residue category

87. To determine the CH_4 emission factor ($EF_{BR,n,y}$), project participants may undertake measurements or use referenced default values.

88. In the absence of more accurate information for $NCV_{BR,n,y}$ and $EF_{BR,n,y}$.[29], a default value of 0.0027 t CH_4/ t biomass is recommended,[30] adjusted by a conservativeness factor (i.e. 0.73) to address the high level of uncertainty. In this case, an emission factor of 0.001971 t CH_4/t biomass should be used.

Box 8. Non-binding best practice example: Baseline emissions due to uncontrolled burning (step 5.1)

Project participants may opt to consider baseline emissions due to uncontrolled burning for those categories of biomass residues, for which baseline has been identified as B1 (biomass residues are dumped or left to decay mainly under aerobic conditions) or B3 (the biomass residues are burnt in an uncontrolled manner).

Example – A project activity involves the utilization of wood residues that are burnt in an uncontrolled manner in the baseline, and empty fruit bunches that are left to decay aerobically. The project participants choose to determine baseline emissions due to uncontrolled burning of biomass based on the monitored quantities of each type of biomass and the default emission factor of 0.001971 t CH_4/t biomass.

$$BE_{BR,B1/B3,y} = GWP_{CH4} \times \left(BR_{woodresidues,y} + BR_{emptyfruitbunches,y}\right) \times \ 0.001971 \text{ (tCH4/t)}$$

[29] 2006 IPCC Guidelines, Volume 4, Table 2.5, default value for agricultural residues.

[30] 2006 IPCC Guidelines, Volume 4, Table 2.5, default value for agricultural residues.

3.3.5.2. Step 5.2: Determine $BE_{BR, B2,y}$

89. For the biomass residues categories, as described in the biomass residues categories table, for which the most likely alternative scenario is that the biomass residues would decay under clearly anaerobic conditions (case B2), project participants shall calculate baseline emissions using the latest approved version of Appendix 8. The variable $BE_{CH4, SWDS,y}$ calculated by the tool corresponds to $BE_{BR,B2,y}$ in this methodology. The waste quantities prevented from disposal ($W_{j,x}$) to be used in the tool shall be those quantities of biomass residues ($BR_{n,B2,y}$), for which B2 has been identified as the baseline scenario.

90. The determination of $BR_{n, B2,y}$ shall be based on the monitored amounts of biomass residues used in the power plants included in the project boundary. Where all biomass residues with the alternative scenario B2 come from one particular source, the monitored quantities of biomass residues from that source used in the project plant can be directly used in the calculation. Where only a part of the biomass residues from one source would be dumped and left to decay under clearly anaerobic conditions (B2), an allocation should be made in line with the information provided for the project activity in the PDD. The allocation should be made in a conservative manner and be consistent with the guidance provided for $BR_{B4,n,y}$.

91. The project developer has the right to use methodologies and CO_2 emissions factors legislatively approved within the territory of the Russian Federation. In this case, the project developer must independently determine the most relevant approach and the level at which the methods will be applied, document and justify the applied algorithms for the validation and verification body. The minimum requirements for determining the baseline for climate projects that are implemented and used for issuing carbon units within the territory of the Russian Federation are established in Order No. 248 of the Ministry of Economic Development of Russia dated 11.05.2022[31]. The approaches proposed in this methodology are consistent with the standardized approach applied at the international level.

4. Project crediting period

92. The starting date of project activities is not regulated.

93. A crediting period for emission reduction projects is a maximum of 5 years with a maximum of two renewable periods of 5 years each, or a maximum of 10 years with no option of renewal.

94. The crediting period begins no earlier than 5 years prior to applying for validation for projects validated until 31 December 2025, and no earlier than 2 years prior to applying for validation for projects validated after 1 January 2026.

95. The additionality and baseline shall be evaluated at the beginning of the crediting period and confirmed or revised at the beginning of the next 5-year phase if the project is implemented in three 5-year phases.

[31] Order No. 248 of the Ministry of Economic Development of Russia dated 11.05.2022 "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".

5. Additionality

96. Additionality shall be demonstrated using Guidelines No. 001 “Demonstration of the additionality of the project activity”[32], taking into account the specifics outlined in this section.

97. Existing measures and government programs relevant to this project activity should be clearly identified in the PDD and included in the assessment of the additionality.

98. Identification of alternatives to the project activity consistent with the applicable laws and regulations is performed in accordance with Guidelines No. 001.

99. The project developer shall provide transparent and documented evidence, and offer conservative interpretations of this documented evidence, as to how it demonstrates the existence and significance of the identified barriers.

100. It is necessary to check whether there are planned instruments such as financing and/or institutional arrangements that could help to overcome the identified barriers during the crediting period. The project developer should describe such instruments, indicate the period of their implementation, and give a conservative evaluation of the sufficiency / insufficiency of these mechanisms to overcome the identified barriers during the crediting period. The application of financial and/or institutional arrangements should be monitored during the project lifetime.

6. Monitoring plan requirements

101. 100% of the data should be monitored if not indicated otherwise in the tables in Appendices 3 and 4. Some parameters need to be monitored continuously during the crediting period, others need to be calculated only once for the crediting period, depending on the data.

102. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards. The project developer should include in the PDD information on the data quality assurance system used. It may be data concerning the inventory, identification and description of measurement equipment used; description of quality assurance/quality control procedures applied to monitoring; organizational procedures; calibration and verification of measurement equipment; connection of standard equipment to reference samples; storage of records.

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

104. If the project developer expects to use different types of data (measurements, default values), it is necessary to document the options used. The calculation of the parameters, emission factors, and source data should be documented electronically and attached to the PDD. The documentation should include all data used to calculate the emission factors and other parameters. The data should be presented in a manner that enables reproducing of the calculation.

105. Data and parameters not monitored and monitored during the project activity are listed in Appendices 3 and 4.

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[32] The climate project implemented in the Russian Federation shall comply with Article 9 of Federal Law No. 296-FZ dated 02.07.2021 “On Limiting Greenhouse Gas Emissions”, as well as the criteria established in accordance with Order No. 248 of the Ministry of Economic Development of Russia dated 11.05.2022 “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”. Guidelines No. 001 are intended as a framework, giving a general understanding for ways and approaches to demonstrate the additionality of project activities. The methodology (sections 5.1 and 5.2) gives a more specific approach to the Guidelines’ statements in relation to this type of project activity.

7. Project Scenario

106. The project developer must document and justify in the PDD the applied algorithms for the validation and verification body. The project developer has the right to use methodologies and CO_2 emission factors legislatively approved within the territory of the Russian Federation[33]. In this case, the project developer must independently determine the most relevant approach and the level at which the methods will be applied, document and justify the applied algorithms for the validation and verification body.

107. The minimum requirements for determining the project emissions for projects that are implemented and used for issuing carbon units within the territory of the Russian Federation are established in Order No. 248 of the Ministry of Economic Development of Russia dated 11.05.2022[31]. The approaches proposed in this methodology are consistent with the standardized approach applied at the international level**Ошибка! Закладка не определена.**.

7.1. Emission reductions

108. Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \quad \text{Equation (18)}$$

Where:

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

7.2. Project emissions

109. Project emissions are calculated as follows:

$$PE_y = PE_{Biomas,y} + PE_{FF,y} + PE_{GR1,y} + PE_{GR2,y} + PE_{CBR,y} + PE_{BG2,y} \quad \text{Equation (19)}$$

Where:

PE_y	=	Project emissions in year *y* (t CO_2)
$PE_{Biomass,y}$	=	Project emissions associated with the biomass and biomass residues in year *y* (t CO_2)
$PE_{FF,y}$	=	Emissions during the year *y* due to fossil fuel consumption at the project site (t CO_2)

[33] See Order No. 371 of the Ministry of Natural Resources and Environment of the Russian Federation dated 27.05.2022 "On approval of methodologies for quantifying greenhouse gas emissions and removals of greenhouse gases", Order No. 15-r of the Ministry of Natural Resources of the Russian Federation (16.04.2015 №) "On approval of guidelines for conducting a voluntary inventory of greenhouse gas emissions in the constituent entities of the Russian Federation", the IPCC Guidelines (2006), the Order of the Ministry of Natural Resources and Ecology of the Russian Federation (29.06.2017 № 330) "On approval of guidelines for quantifying the volume of indirect energy emissions of greenhouse gases"

$PE_{GR1,y}$	=	Emissions during the year *y* due to grid electricity imports to the project site (t CO_2)
$PE_{GR2,y}$	=	Emissions due to a reduction in electricity generation at the project site in year *y* (t CO_2)
$PE_{CBR,y}$	=	Emissions from the combustion of biomass during the year *y* (t CO2e)
$PE_{BG2,y}$	=	Emissions from the production of biogas in year *y* (t CO2e)

7.2.1. Determination of $PE_{Biomass,y}$

110. $PE_{Biomass,y}$ shall be determined on the basis of Appendix 10 and cover the following emission sources:

(a) project emissions resulting from the cultivation of biomass in a dedicated plantation of a project activity that uses biomass (PE_{BC});

(b) project emissions resulting from the transportation of biomass (PE_{BT});

(c) project emissions resulting from the processing of biomass (PE_{BP});

(d) project emissions resulting from the transportation of biomass residues (PE_{BRT}) if the project consumes biomass residues;

(e) project emissions resulting from the processing of biomass residues (PE_{BRP}) if the project consumes biomass residues.

7.2.2. Determination of $PE_{FF,y}$

111. The following emission sources shall be included in determining $PE_{FF,y}$:

(a) Emissions from on-site fossil fuel consumption for the generation of electric power and heat. This includes all fossil fuels used at the project site in heat generators (e.g. boilers) for the generation of electric power and heat.

(b) Emissions from on-site fossil fuel consumption of auxiliary equipment and systems related to the generation of electric power and heat. This includes fossil fuels required for the operation of auxiliary equipment related to the power and heat plants (e.g. pumps, fans, cooling towers, instrumentation and control tools, etc.) which are not accounted for in (a) above.

112. Appendix 1 shall be used to calculate $PE_{FF,y}$. All combustion processes *j* as described in the two bullets above should be included.

113. Fossil fuels required for the operation of equipment related to on-site or off-site preparation, storage, processing and transportation of fuels and biomass and/or biomass residues (e.g. for mechanical treatment of the biomass, conveyor belts, driers, pelletization, shredding, briquetting processes, etc.) shall be treated under $PE_{Biomass,y}$.

Box 9. Non-binding best practice example: Emissions due to fossil fuel consumption

Project participants should determine the project emissions due to fossil fuel consumption taking into account the on-site fossil fuel consumption for the generation of electric power and heat, and on-site fossil fuel consumption of auxiliary equipment and systems related to the generation of electric power and heat. Example - A project activity that utilizes fossil fuels purchased from the market as auxiliary fuel for the generation of electric power and heat. The quantities of fossil fuel purchased are monitored continuously using mass or volume meters and cross-checked with invoices that can be identified specifically for the proposed project activity.

7.2.3. Determination of $PE_{GR1,y}$

114. If electricity is imported from the grid to the project site during year y, corresponding emissions should be accounted for as project emissions, as follows:

$$PE_{GR1,y} = EF_{EG,GR,y} \times EL_{PJ,imp,y} \qquad \text{Equation (20)}$$

Where:

$PE_{GR1,y}$	=	Emissions during the year y due to grid electricity imports to the project site (t CO_2)
$EL_{PJ,imp,y}$	=	Project electricity imports from the grid in year y (MWh)
$EF_{EG,GR,y}$	=	Grid emission factor in year y (t CO_2/MWh)

7.2.4. Determination of $PE_{GR2,y}$

115. If $EL_{balance,PO,y} < EL_{BL,BR,PO,y}$ (Step 3.3.2) or $EL_{balance,FF,y} < EL_{BL,FF,y}$ (Step 4.2.2), the amount of electricity generated on-site in the baseline is higher than the amount of electricity generated in the project scenario. In such cases, it is assumed that an equivalent amount of electricity is generated during year y in order to offset this reduction in electricity generation at the project site. Corresponding emissions should be accounted for as project emissions as follows:

$$PE_{GR2,y} = EF_{EG,GR,y} \times EL_{PJ,offset,y} \qquad \text{Equation (21)}$$

Where:

$PE_{GR2,y}$	=	Emissions due to a reduction in electricity generation at the project site in year y (tCO_2)
$EF_{EG,GR,y}$	=	Grid emission factor in year y (tCO_2/MWh)
$EL_{PJ,offset,y}$	=	Electricity that would be generated in the baseline that exceeds the generation of electricity during year y (MWh)

7.2.5. Determination of $PE_{CBR,y}$

116. If project proponents chose to include emissions due to uncontrolled burning or decay of biomass residues ($BE_{CBR,y}$) in the calculation of baseline emissions, emissions from the combustion of this

category of biomass residues have also to be included in the project scenario. Otherwise, this emission source may be excluded. Corresponding emissions are calculated as follows:

$$PE_{CBR,y} = GWP_{CH4} \times EF_{CH4,BR} \times \sum_{n} BR_{PJ,n,y} \times NCV_{BR,n,y} \quad \text{Equation (22)}$$

Where:

$PE_{CBR,y}$	=	Emissions from the combustion of biomass residues during the year *y* (tCO_2e)
GWP_{CH4}	=	Global Warming Potential of methane valid for the commitment period ($tCO_2/tCH4$)
$EF_{CH4,BR}$	=	CH_4 emission factor for the combustion of biomass residues in the project plant (tCH_4/GJ)
$BR_{PJ,n,y}$	=	Quantity of biomass residues of category *n* used in the project activity in year *y* (tons on dry basis)
$NCV_{BR,n,y}$	=	Net calorific value of biomass residue of category *n* in year *y* (GJ/ton on dry basis)

117. To determine the CH_4 emission factor ($EF_{CH4,BR}$), project participants may conduct measurements at the plant site or use IPCC default values, as provided in Table 3 below. The uncertainty of the CH_4 emission factor is in many cases relatively high. In order to reflect this and for the purpose of providing conservative estimates of emission reductions, a conservativeness factor of 1.37 is applied to the CH_4 emission factor.

Table 3. Default CH_4 emission factors for combustion of biomass residues[34]

	Default emission factor (kg CH_4 / TJ)	Assumed uncertainty
Wood waste	30	300%
Sulphite lyes (Black Liquor)	3	300%
Other solid biomass residues	30	300%
Liquid biomass residues	3	300%

7.2.6. Determination of $PE_{BG2,y}$

118. In case the project includes biogas, the consideration of project emissions associated with the production of biogas depends on the selected baseline scenario for biogas and whether the biogas is sourced from a registered project activity according to the following provisions:

(a) In case the biogas is provided by a registered project activity, the project emissions will be covered in the PDD of the registered project activity.

[34] Values are based on the 2006 IPCC Guidelines, Volume 2, Chapter 2, Tables 2.2 to 2.6.

(b) In case the biogas is not provided by a registered project activity:

(i) If baseline scenario BG1 is selected, the project emissions should be included in this proposed project activity. The emission source shall include project emissions from physical leakage of methane.

(ii) In case of baseline scenario BG2 and/or BG3, no project emissions need to be included.

7.3. Risk management

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

(a) the main stages of the implementation of the climate project;

(b) description of the risks that may arise at each stage of the climate project;

(c) 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);

(d) description of the impact of each risk on the results of the entire project (for this, the rating options low, medium, high or any other understandable numerical scales can be used);

(e) description of the period of influence of each risk on the entire climate project;

(f) description of the developed measures to minimize or avoid each type of risks;

(g) description of the time period required for the implementation of each measure that reduces or prevents the occurrence of risks.

120. The recommended table for completion, reflecting the outcomes of the risk management measures is given in Appendix 5.

8. Leakage assessment

121. According to Order No. 248 of the Ministry of Economic Development of Russia dated 11.05.2022[35], 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 any project leakage [36] if it exists.

122. The project developer shall independently determine the most relevant methods to assess the leakage, document and justify the applied algorithms for the validation and verification body, including the approaches applied at the international level.

123. The project developer shall indicate in the PDD which leakage sources are included. If emission sources are not considered, the project developer shall provide proper justification in the PDD.

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[35] Appendix No. 1 to Order No. 248 of the Ministry of Economic Development of Russia dated 11.05.2022, paragraph "c".

[36] Leakage (for a project activity) means 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).

9. Non-permanence risk analysis

124. The section is not applicable to this methodology.

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

125. The climate project should demonstrate its compliance with all legal requirements in the jurisdiction where it is located (including but not limited to the Reference list methodologies). The project developer should minimize the 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 or 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 natural area.

126. Efforts should be made to avoid double counting[37] between project areas (project boundaries), between company reporting and reporting on the project, between the reporting of different companies, between the constituent entities 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 contribution of the Russian Federation defined at the national level.

127. **Recommendations for updating or keeping the baseline unchanged at the renewal of the crediting period and project activity**

128. 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.

129. The renewal of the crediting period of a registered project activity shall only be granted if the project developer can provide evidence that the original project baseline is still valid or has been updated taking account of new data where applicable.

130. The project developer shall update those sections of the project design document relating to the baseline, estimated emission reductions and the monitoring plan using an approved baseline and monitoring methodology: the latest approved version of the baseline and monitoring methodology applied in the original PDD of the registered project activity shall be used whenever applicable.

131. The demonstration of the validity of the original baseline or its update does not require a reassessment of the baseline scenario, but rather an assessment of the emissions, which would have resulted from that scenario. The additionality at the renewal of the crediting period is checked for

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[37] 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

compliance with the criteria under Guidelines No. 001 “Demonstration of the additionality of the project activity” as at the date of the beginning of the new crediting period.

132. If the baseline of a registered project has been revised or updated, the project developer must justify the need to deviate from the approved methodology to the validation and verification body in order to extend the crediting period.

133. Assessment of the validity of the original/current baseline and to updates to the baseline at the renewal of a crediting period. The procedure to assess the validity of the baseline and to update the baseline at the renewal of a crediting period consists of two steps. The first step provides an approach to evaluate whether the current baseline is still valid for the next crediting period. The second step provides an approach to update the baseline if the current baseline is not valid anymore for the next crediting period (see Appendix 9).

11. Normative references

ACM0006 Large-scale Consolidated Methodology Electricity and heat generation from biomass. Version 16.0. CDM Methodology.

Order No. 248 of the Ministry of Economic Development of Russia dated 11.05.2022 "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 30.05.2022, No. 68642).

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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 Rosstandart Order No. 1033-st dated 30.09.2021).

Order No. 371 of the Ministry of Natural Resources and Environment of Russia dated 27.05.2022 "On approval of methods for quantitative determination of greenhouse gas emissions and greenhouse gas removals" (from 1 March 2023, except for certain provisions, coming into force on 1 March 2024).

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.

134. TOOL01 Methodological tool. Tool for the demonstration and assessment of additionality. Version 07.0.0. CDM Methodology.

135. TOOL02 Methodological tool. Combined tool to identify the baseline scenario and demonstrate additionality. Version 07.0. CDM Methodology.

136. TOOL09 Methodological tool. Determining the baseline efficiency of thermal or electric energy generation systems. Version 03. CDM Methodology.

137. TOOL12 Methodological tool. Project and leakage emissions from transportation of freight. Version 01.1.0. CDM Methodology.

TOOL16 Methodological tool. Project and leakage emissions from biomass. Version 05.0. CDM Methodology..

Methodological Tool. Tool to determine the remaining lifetime of equipment. Version 01. CDM Methodology

Methodological Tool. Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period. Version 03.0.1. CDM Methodology.

Appendix 1. Calculation of CO_2 emissions from fossil fuel combustion

1. This tool provides procedures to calculate project and/or leakage CO_2 emissions from the combustion of fossil fuels. It can be used in cases where CO_2 emissions from fossil fuel combustion are calculated based on the quantity of fuel combusted and its properties. Methodologies using this tool should specify to which combustion process *j* this tool is being applied.

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

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

Where:

$PE_{FC,j,y}$	CO_2 emissions from fossil fuel combustion in process *j* during the year *y* (tCO_2/yr)
$FC_{i,j,y}$	Quantity of type *i* fuel combusted in process *j* during the year *y* (mass or volume unit/yr)
$COEF_{i,y}$	CO_2 emission coefficient of type *i* fuel in year *y* (t CO_2/mass or volume unit)
i	Fuel types combusted in process *j* during the year *y*

3. The CO_2 emission coefficient $COEF_{i,y}$ can be calculated using one of the following two options. *Option A* should be the preferred approach if the necessary data are available.

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

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

$$COEF_{i,y} = w_{C,i,y} \times 44/12$$

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

$$COEF_{i,y} = w_{C,i,y} \times \rho_{i,y} \times 44/12$$

Where:

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

5. **Option B.** The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on the net calorific value and CO_2 emission factor of the type *i* fuel, using the following approach:

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

Where:

$COEF_{i,y}$	CO_2 emission coefficient of type *i* fuel in year *y* (t CO_2/mass or volume unit)
$NCV_{i,y}$	Weighted average net calorific value of type *i* fuel in year *y* (GJ/mass or volume unit)
$EF_{CO2,i,y}$	Weighted average CO2 emission factor of type *i* fuel in year *y* (tCO2/GJ)
i	Fuel types combusted in process *j* during the year *y*

Appendix 2. Determination of the remaining lifetime of equipment

1. The tool provides guidance to determine the remaining lifetime of baseline or project equipment. The tool may, for example, be used for project activities which involve the replacement of existing equipment with new equipment or which overhaul existing equipment as part of energy efficiency improvement activities.

2. This tool provides procedures to determine the following parameter: **Remaining lifetime (RL).** The remaining lifetime of the equipment is the time for which the existing equipment can continue to operate before it has to be replaced/discarded for technical reasons, such as the age of the equipment, safety reasons, or deteriorated performance. The remaining lifetime is expressed in years or hours of operation.

3. For project activities that involve several equipment types, project participants can either determine the remaining lifetime for each equipment type or determine the remaining lifetime as the most conservative of the individual remaining lifetimes of the equipment by applying any one of the options (a) to (c).

4. If the remaining lifetime of existing equipment, which would continue to operate in the baseline, is extended due to the implementation of a project activity, the crediting of emission reductions should be limited to the shortest estimated remaining lifetime of the baseline equipment. In other words, the earliest point in time when any of the existing equipment would need to be replaced or overhauled in the absence of the project activity should be used, unless the methodology specifies otherwise. Small equipment accessories/components such as small pumps, motors, valves etc. that are generally replaced as part of regular maintenance activities do not need to be included in the scope of determination of the remaining lifetime.

Option (a): Use manufacturer's information for the technical lifetime of equipment and compare to the date of first commissioning

5. In this option, the remaining lifetime is determined as a difference between the technical lifetime and the operational time.

6. This option can only be applied if:

    (a) the manufacturer's information on the technical lifetime of the equipment is available;

    (b) the project participants can demonstrate that the equipment has been operated and maintained according to the recommendations of the equipment supplier to ensure that the technical lifetime specified by the manufacturer is not reduced;

    (c) there are no periodic replacement schedules or scheduled replacement practices specific to the industrial facility, that require early replacement of equipment before the expiry of the technical lifetime; and

    (d) the equipment has no design fault or defect and did not have any industrial accident due to which the equipment cannot operate at rated performance levels.

7. Documentation supporting these conditions should be provided, for example information on the operational history of the equipment.

8. The operational time shall be determined based on the operational history of the equipment from the date of its first commissioning.

9. In cases where the equipment was overhauled prior to the implementation of the project activity or energy efficiency improvement measures were undertaken, which increased the remaining lifetime, the technical lifetime provided by the equipment supplier may not be valid anymore. In this case, project participants should follow one of the following approaches:

(a) If the overhaul was undertaken by the equipment manufacturer, the equipment manufacturer may provide a revised estimation of the technical lifetime.

(b) Apply the original technical lifetime provided by the equipment manufacturer at the time of equipment installation, as long as assuming a shorter lifetime is conservative (e.g. in the case of baseline equipment which is replaced under the project activity).

(c) Choose other options provided in this tool to determine the remaining lifetime.

10. In case of relocated equipment (equipment which was already in operation at another site and which is transferred to the site of the project activity where it continues to operate), the operation history at the previous site(s) should be considered when establishing the operational time.

Option (b): Obtain an expert evaluation

11. In this option, an independent expert having relevant experience in evaluating the remaining lifetime for the type of equipment can be requested to determine the remaining lifetime of the equipment. The information that could be evaluated includes an analysis of:

(a) the operational history of the equipment to identify the past performance, equipment overhauls, failures/accidents, capacity upgrades/degradations, replacements etc.;

(b) the current operation and maintenance practices;

(c) documented specific sectoral/industry practices for replacements;

(d) conducting tests on the equipment, such as magnetic particle examinations, ultrasonic testing, metallurgical analysis, etc.

12. The expert should document his methods and conclusions and provide an expert evaluation stating the estimated remaining lifetime of the equipment. All the relevant documentation should be presented to the DOE for validation.

Option (c): Use default values

13. In this option, project participants may use the following default values for the technical lifetime and determine the remaining lifetime as the difference of the technical lifetime and the operational time.

14. This option can only be applied if:

(a) the project participants can demonstrate that the equipment has been operated and maintained according to the recommendations of the equipment supplier;

(b) there are no periodic replacement schedules or scheduled replacement practices specific to the industrial facility, that require early replacement of equipment before the expiry of the technical lifetime; and

(c) the equipment has no design fault or defect and did not have any industrial accident due to which the equipment cannot operate at rated performance levels.

15. Documentation supporting these conditions should be provided, for example information on the operational history of the equipment.

16. The operational time shall be determined based on the operational history of the equipment from the date of its first commissioning. In case of relocated equipment (equipment which was already in operation at another site and which is transferred to the site of the project activity where it continues to operate), the operation history at the previous site(s) should be considered when establishing the operational time.

17. For the technical lifetime, the following default values apply[38]:

Equipment	**Default value for Technical lifetime**
Boilers	25 years
Steam Turbines	25 years
Gas turbines, up to 50 MW capacity	150,000 hours
Gas turbines, above 50 MW capacity	200,000 hours
Hydro turbines	150,000 hours
Electric Generators, air cooled	25 years
Electric generators, hydrogen cooled or water cooled	30 years
Wind turbines, onshore	25 years
Wind turbines, offshore	20 years
Diesel/oil/gas fired generator sets	50,000 hours
Transformers	30 years
Heaters, chillers, pumps, etc. used in HVAC systems	15 years

[38] CDM. Methodological Tool. Tool to determine the remaining lifetime of equipment (Version 01)

Appendix 3. Data and parameters not monitored

№	Data / Parameter	Data unit	Description	Source of data	Measurement procedures	Monitoring frequency	Any comment/ QA/QC procedures
1.	Biomass categories and quantities used for the selection of the baseline scenario and assessment of additionality	– Category (i.e. bagasse, rice husks, empty fruit bunches, etc.) – Source (e.g. produced on-site, obtained from an identified biomass residues producer, obtained from a biomass residues market, from dedicated plantations etc.) – Fate in the absence of the project activity (scenarios B) – Use in the project scenario (scenarios P) – Quantity (tons on dry basis)	Explain and document transparently in the PDD, which quantities of which biomass categories are used in which installation(s) under the project activity and what is their baseline scenario. Include the quantity of each category of biomass (tons). For the selection of the baseline scenario and demonstration of additionality, at the validation stage, an ex ante estimation of these quantities should be provided	On-site assessment of biomass categories and quantities			This parameter is related to the procedure for the selection of the baseline scenario and assessment of additionality
2.	$BR_{HIST,n,x}$	tons on dry basis	Quantity of biomass residues of category *n* used for power or heat generation at the project site in year *x* prior to the date of submission of the PDD for	On-site measurements	Use weight or volume meters. Adjust for the moisture content in order to determine the quantity of dry biomass. The quantity shall be cross-checked with the quantity of heat generated and any fuel purchase receipts (if		Biogas should be included as appropriate if applicable (in which case convenient units such as m^3 should be used)

			validation of the project activity (tons on dry basis)		available). In case of volume meters use the fuel density to convert the measurement to mass basis		
3.	$BR_{n,h,x}$	tons on dry basis	Quantity of biomass residues of category *n* used in heat generator *h* in year *x* (tons on dry basis)	On-site measurements	Use weight or volume meters. Adjust for the moisture content in order to determine the quantity of dry biomass. The quantity shall be cross-checked with the quantity of heat generated and any fuel purchase receipts (if available)		Biogas should be included as appropriate if applicable (in which case convenient units such as m^3 should be used)
4.	$FF_{f,h,x}$	mass or volume unit/yr	Quantity of fossil fuel type *f* fired in heat generator *h* in year *x* (mass or volume unit/yr)	On-site measurements	Use weight or volume meters. Adjust for the moisture content in order to determine the quantity of dry biomass. The quantity shall be cross-checked with the quantity of heat generated and any fuel purchase receipts (if available). In case of volume meters use the fuel density to convert the measurement to mass basis		
5.	$HG_{h,x}$	GJ	Net quantity of heat generated in heat generator *h* in year *x* (GJ/yr)	On-site measurements	This parameter should be determined as the difference of the enthalpy of the heat (steam or hot water) generated by the heat generators(s) [in the project activity, monitored during year *y*,] minus the enthalpy of the feed-water, the boiler blow-down and any condensate return. The respective enthalpies should be determined based on the mass (or volume) flows, the temperatures and, in case of superheated steam, the pressure. Steam tables or appropriate thermodynamic equations may be used to calculate the enthalpy as a function of temperature and pressure		In the absence of temperature and pressure records, use the default values from equipment datasheets as a reference
6.	$HG_{BR,CG/PO,x,i,j}$	GJ	Quantity of heat used in heat engine *i/j* in year *x* (GJ)	On-site measurements	This parameter should be determined as the difference of the enthalpy of the process heat (steam or hot water) generated by the heat generators(s) [in the project activity, monitored during year *y*,] minus the enthalpy of the feed-water, the boiler blow-down and any condensate return. The respective enthalpies should be determined based on the mass (or volume) flows, the temperatures and, in case of		

					superheated steam, the pressure. Steam tables or appropriate thermodynamic equations may be used to calculate the enthalpy as a function of temperature and pressure		
7.	$HC_{BR,CG/PO,x,i/j}$	GJ	Quantity of process heat extracted from the heat engine *i/j* in year *x* (GJ)	On-site measurements	This parameter should be determined as the difference of the enthalpy of the process heat (steam or hot water) supplied to process heat loads in the project activity minus the enthalpy of the feed-water, the boiler blow-down and any condensate return to the heat generators. The respective enthalpies should be determined based on the mass (or volume) flows, the temperatures and, in case of superheated steam, the pressure. Steam tables or appropriate thermodynamic equations may be used to calculate the enthalpy as a function of temperature and pressure		
8.	$EL_{BR,CG/PO,x,i/j}$	MWh	Quantity of electricity generated in heat engine *i/j* in year *x* (MWh)	On-site measurements	Electricity meters		
9.	P_x	Use suitable units, as appropriate	Quantity of the main product of the production process (e.g. sugar cane, rice) produced in year *x* from plants operated at the project site	On-site measurements			
10.	$CAP_{HG,h}$	GJ/h	Baseline capacity of heat generator *h* (GJ/h)	On-site measurements or reference plant design parameters	This parameter should reflect the design maximum heat generation capacity (in GJ/h) of the baseline heat generator *h*. It should be based on the installed capacity of the heat generator. Project participants should document transparently and justify in the PDD how this parameter was determined		
11.	$CAP_{EG,CG,i}$ $CAP_{EG,PO,j}$	MW	$CAP_{EG,CG,i}$ = Baseline electricity generation capacity in on-site and off-site plants in year y (MWh) of cogeneration-type heat engine *i* (MW). $CAP_{EG,PO,j}$ = Baseline electricity generation capacity	On-site measurements or reference plant design parameters	This parameter should reflect the design maximum electricity generation capacity (in MW) of the baseline heat engines *i* and *j*. It should be based on the installed capacity of the heat engines. Project participants should document transparently and		

			of power-only-type heat engine *j* (MW)		justify in the PDD how this parameter was determined		
12.	$LFC_{HG,h}$	Ratio	Baseline load factor of heat generator *h* (ratio)	On-site measurements or reference plant design parameters	This parameter should reflect the maximum load factor (i.e. the ratio between the ‘actual heat generation’ of the heat generator and its ‘design maximum heat generation’ along one year of operation) of the baseline heat generator *h*, taking into account downtime due to maintenance, seasonal operational patterns, and any other technical constraints. Project participants should document transparently and justify in the PDD how this parameter was determined (e.g. using historical records)		
13.	$HPR_{BL,I}$	Ratio	Baseline heat-to-power ratio of the heat engine *i* (ratio)	On-site measurements or reference plant design parameters			
14.	$LFC_{EG,CG,i}$ $LFC_{EG,CG,j}$	Ratio	$LFC_{EG,CG,i}$ = Baseline load factor of cogeneration-type heat engine *i* (ratio) $LFC_{EG,PO,j}$ = Baseline load factor of power-only-type heat engine *j* (ratio)	On-site measurements or reference plant design parameters	This parameter should reflect the maximum load factor (i.e. the ratio between the ‘actual electricity generation’ of the heat engine and its ‘design maximum electricity generation’ along one year of operation) of the baseline heat engine *i* or *j*. The actual electricity generation of the heat engine should be determined taking into account downtime due to maintenance, seasonal operational patterns, and any other technical constraints. Project participants should document transparently and justify in the PDD how this parameter was determined		
15.	$EF_{BL,CO2,FF}$	tCO_2/GJ	CO_2 emission factor of the fossil fuel type that would be used for power generation at the project site in the baseline ($t\ CO_2/GJ$)	Either conduct measurements or use accurate and reliable local or national data where available. Where such data is not available, use IPCC default emission factors (country-specific, if available) if they are deemed to reasonably represent local circumstances. Choose the	Measurements shall be carried out at reputed laboratories and according to relevant international standards	In case of plants existing before project implementation, the lowest CO_2 emission factor should be used in case of multi fuel plants	

				value in a conservative manner and justify the choice			
16.	$\eta_{BL,FF}$	Ratio	Efficiency of the fossil fuel power plant(s) at the project site in the baseline	Either use the higher value among (a) the measured efficiency and (b) the manufacturer's information on the efficiency; or use default values as provided in Appendix 1 of the "Tool to calculate the emission factor for an electricity system"; or assume an efficiency of 100%	If measurements are conducted, use recognized standards for the measurement of the heat generator efficiency. Where possible, use preferably the direct method (dividing the net heat generation by the energy content of the fuels fired during a representative time period), as it is better able to reflect average efficiencies during a representative time period compared to the indirect method (determination of fuel supply or heat generation and estimation of the losses). Document measurement procedures and results and the manufacturer's information transparently in the PDD		
17.	$NCV_{BR,n,x}$	GJ/tons on dry basis	Net calorific value of biomass residues of category *n* in year *x*	Either conduct measurements or use accurate and reliable local or national data where available. Where such data is not available, use IPCC default net calorific values (country-specific, if available) if they are deemed to reasonably represent local circumstances. Choose the values in a conservative manner and justify the choice	Measurements shall be carried out at reputed laboratories and according to relevant international standards		The NCV is to be calculated for wet biomass as used in the heat generator (i.e. deducting the energy used for the evaporation of the water contained in the biomass residues). Biogas should be included as appropriate if applicable (in which case convenient units such as GJ/m^3 should be used)
18.	$NCV_{FF,f,x}$	GJ/mass or volume unit	Net calorific value of fossil fuel type *f* in year *x* (GJ/mass or volume unit)	Either conduct measurements or use accurate and reliable local or national data where available. Where such data is not available, use IPCC default net calorific values (country-specific, if available) if they are deemed to reasonably represent local circumstances. Choose the values in a conservative	Measurements shall be carried out at reputed laboratories and according to relevant international standards		

				manner and justify the choice			
19.	GWP_{CH4}	tCO_2e/tCH_4	Global Warming Potential of methane valid for the commitment period ($tCO2/tCH4$)	IPCC	Shall be updated according to any future COP/MOP decisions		
20.	$\varphi_{default}$		Default value for the model correction factor to account for model uncertainties		For baseline emissions: refer to the table below to identify the appropriate factor based on the application of the tool and theclimate where the SWDS is located. **Default values for the model correction factor:** **Humid/wet conditions – 0.85** **Dry conditions – 0.80**		
21.	OX		Oxidation factor (reflecting the amount of methane from SWDS that is oxidized in the soil or other material covering the waste)	Based on an extensive review of published literature on this subject, including the IPCC 2006 Guidelines for National Greenhouse Gas Inventories	0.1		When methane passes through the top-layer, part of it is oxidized by methanotrophic bacteria to produce CO2. The oxidation factor represents the proportion of methane that is oxidized to CO2 This should be distinguished from the methane correction factor (MCF) which is to account for the situation that ambient air might intrude into the SWDS and prevent methane from being formed in the upper layer of SWDS
22.	F		Fraction of methane in the SWDS gas (volume fraction)	IPCC 2006 Guidelines for National Greenhouse Gas Inventories	0.5		Upon biodegradation, organic material is converted to a mixture of methane and carbon dioxide
23.	$DOC_{f,default}$	Weight fraction	Default value for the fraction of degradable organic carbon (DOC) in MSW that decomposes in the SWDS	IPCC 2006 Guidelines for National Greenhouse Gas Inventories	0.5		This factor reflects the fact that some degradable organic carbon does not degrade, or degrades very slowly, in the SWDS. This default value can only be used if the tool is applied to MSW. An alternative to using the default factor is to estimate $DOCf,y$ or using equations in Appendix 8.
24.	$MCF_{default}$		Methane correction factor	IPCC 2006 Guidelines for National Greenhouse Gas Inventories	In case that the SWDS does not have a water table above the bottom of the		MCF accounts for the fact that unmanaged SWDS produce less methane from a given amount of

					SWDS, then select the applicable value from the following: (a) 1.0 for **anaerobic managed solid waste disposal sites**. (b) 0.5 for **semi-aerobic managed solid waste disposal sites**. (c) 0.8 for **unmanaged solid waste disposal sites – deep.** (d) 0.4 for **unmanaged-shallow solid waste disposal sites or stockpiles that are considered SWDS.**		waste than managed SWDS, because a larger fraction of waste decomposes aerobically in the top layers of unmanaged SWDS.

Appendix 4. Data and parameters monitored

№	Data / Parameter	Data unit	Description	Source of data	Measurement procedures	Monitoring frequency	Any comment/ QA/QC procedures
1.	Biomass categories and quantities used in the project activity	– Category (i.e. bagasse, rice husks, empty fruit bunches, tree bark etc.); – Source (e.g. produced on-site, obtained from an identified biomass residues producer, obtained from a biomass residues market, dedicated plantations etc.); – Fate in the absence of the project activity (scenarios B); – Use in the project scenario (scenarios P and H); Quantity (tons on dry basis)	Explain and document transparently in the PDD, which quantities of which biomass categories are used in which installation(s) under the project activity and what is their baseline scenario. Include the quantity of each category of biomass (tons on dry basis). These quantities should be updated every year of the crediting period as part of the monitoring plan so as to reflect the actual use of biomass in the project scenario. These updated values should be used for emissions reductions calculations. Along the crediting period, new categories of biomass (i.e. new types, new sources, with different fate) can be used in the project activity. In this case, a new line should be added to the table. If those new categories are of the type B1, B2 or B3, the baseline scenario for those categories of biomass residues should be assessed using the procedures outlined in the guidance provided in the procedure for the selection of the baseline scenario and demonstration of additionality	On-site measurements	Use calibrated weight meters. Adjust for the moisture content in order to determine the quantity of dry biomass	Data monitored continuously and aggregated as appropriate, to calculate emissions reductions	Crosscheck the measurements with an annual energy balance that is based on purchased quantities and stock changes

2.	For biomass residues categories for which scenario B1, B2 or B3 is deemed a plausible baseline alternative, the project participants shall demonstrate that this is a realistic and credible alternative scenario	Tons	– Quantity of available biomass residues of category *n* in the region – Quantity of biomass residues of category *n* that are utilized (e.g. for energy generation or as feedstock) in the defined geographical region Availability of a surplus of biomass residues category *n* (which cannot be sold or utilized) at the ultimate supplier to the project and a representative sample of other suppliers in the defined geographical region	Surveys or statistics		At the validation stage for biomass residues categories identified ex ante, and every time new biomass residues categories are included during the crediting period	
3.	$BR_{PJ,n,y}$	Tons on dry basis	Quantity of biomass of category *n* used in the project activity in year *y* (tons on dry basis)	On-site measurements	Use calibrated weight meters. Adjust for the moisture content in order to determine the quantity of dry biomass	Data monitored continuously and aggregated as appropriate, to calculate emissions reductions	Crosscheck the measurements with an annual energy balance that is based on purchased quantities and stock changes. The biomass residue quantities used should be monitored separately for (a) each category of biomass residue and each source (e.g. produced on-site, obtained from biomass residues suppliers, obtained from a biomass residues market, obtained from an identified biomass residues producer, etc.). Biogas should be included as appropriate if applicable (in which case convenient units such as m^3 should be used)
4.	$BR_{B1/B3,n,y}$	Tons on dry basis	Quantity of biomass residues of category *n* used in the project activity in year *y* for which the baseline scenario is B1 or B3 (tons on dry basis)	On-site measurements	Use calibrated weight meters. Adjust for the moisture content in order to determine the quantity of dry biomass	Data monitored continuously and aggregated as appropriate, to calculate emissions reductions	Crosscheck the measurements with an annual energy balance that is based on purchased quantities and stock changes. Biogas should be included as appropriate if applicable (in which case convenient units such as m^3 should be used)
5.	$BR_{B4,n,y}$	Tons of dry matter	Quantity of biomass residues of category n used in the project	On-site measurements	Use calibrated weight meters. Adjust for the moisture content	Data monitored continuously and	Crosscheck the measurements with an annual energy balance

			activity in year *y*, for which the baseline scenario is B4 (tons on dry basis)		in order to determine the quantity of dry biomass	aggregated as appropriate, to calculate emissions reductions	that is based on purchased quantities and stock changes. Biogas should be included as appropriate if applicable (in which case convenient units such as m^3 should be used)
6.	$BR_{B5,n,y}$	Tons on dry basis	Quantity of biomass residues of category *n* used in the project activity in year *y* for which the baseline scenario is B5 (tons on dry basis)	On-site measurements	Use calibrated weight meters. Adjust for the moisture content in order to determine the quantity of dry biomass	Data monitored continuously and aggregated as appropriate, to calculate emissions reductions	Crosscheck the measurements with an annual energy balance that is based on purchased quantities and stock changes. The procedures in Step 1.4 should also be followed
7.	$EF_{BR,n,y}$	tCH_4/GJ	CH_4 emission factor for uncontrolled burning of the biomass residues of category *n* during the year *y* (tCH4/GJ)	Conduct measurements or use reference default values	To determine the CH_4 emission factor, project participants may undertake measurements or use referenced default values. In the absence of more accurate information, it is recommended to use 0.0027 t CH_4 per ton of biomass as a default value for the product of NCV_k and $EF_{burning,CH4,k,y}$		
8.	$EF_{FF,y,f}$	tCO_2/GJ	CO_2 emission factor for fossil fuel of type *f* in year *y* (tCO_2/GJ)	Either conduct measurements or use accurate and reliable local or national data where available. Where such data is not available, use IPCC default emission factors (country-specific, if available) if they are deemed to reasonably represent local circumstances. Choose the value in a conservative manner and justify the choice	Measurements shall be carried out at reputed laboratories and according to relevant international standards	In case of measurements: At least every six months, taking at least three samples for each measurement. In case of other data sources: Review the appropriateness of the data annually	Check consistency of measurements and local/national data with the default values provided by the IPCC. If the values differ significantly from IPCC default values, possibly collect additional information or conduct measurements
9.	$EF_{CH4,BR}$	tCH_4/GJ	CH_4 emission factor for the combustion of biomass residues in the project plant (tCH4/GJ)	On-site measurements or default values, as provided in Table 3	The CH_4 emission factor may be determined based on a stack gas analysis using calibrated analyzers	At least quarterly, taking at least three samples per measurement	Check the consistency of the measurements by comparing the measurement results with measurements from previous years, relevant data sources (e.g. values in the literature, values used in the national GHG inventory) and default values by the IPCC. If the measurement results differ significantly from previous measurements or other

							relevant data sources, conduct additional measurements. Monitoring of this parameter for project emissions is only required if CH_4 emissions from biomass combustion are included in the project boundary. Note that a conservative factor shall be applied, as specified in the baseline methodology
10.	$EF_{CO2,LE}$	t CO_2/GJ	CO_2 emission factor of the most carbon intensive fossil fuel used in the country (t CO_2/GJ)	Identify the most carbon intensive fuel type from the national communication, other literature sources (e.g. IEA). Possibly consult with the national agency responsible for the national communication/GHG inventory. If available, use national default values for the CO_2 emission factor. Otherwise, IPCC default values may be used		Annually	
11.	$HC_{BL,y}$	GJ	Baseline process heat generation in year *y* (GJ)	On-site measurements	This parameter should be determined as the difference of the enthalpy of the process heat (steam or hot water) supplied to process heat loads in the project activity minus the enthalpy of the feed-water, the boiler blow-down and any condensate return to the heat generators. The respective enthalpies should be determined based on the mass (or volume) flows, the temperatures and, in case of superheated steam, the pressure. Steam tables or appropriate thermodynamic equations may be used to calculate the enthalpy as a function of temperature and pressure	Calculated based on continuously monitored data and aggregated as appropriate to calculate emissions reductions	
12.	$EL_{PJ,gross,y}$	MWh	Gross quantity of electricity generated in all power plants which are located at the project site and included in the project boundary in year *y* (MWh)	On-site measurements	Use calibrated electricity meters	Data monitored continuously and aggregated as appropriate, to	The consistency of metered electricity generation should be cross-checked with receipts from electricity sales (if available) and the quantity of

						calculate emissions reductions	fuels fired (e.g. check whether the electricity generation divided by the quantity of fuels fired results in a reasonable efficiency that is comparable to previous years)
13.	$EL_{PJ,imp,y}$	MWh	Project electricity imports from the grid in year y (MWh)	On-site measurements	Use calibrated electricity meters	Data monitored continuously and aggregated as appropriate, to calculate emissions reductions	The consistency of metered electricity generation should be cross-checked with receipts from electricity purchases
14.	$EL_{PJ,aux,y}$	MWh	Total auxiliary electricity consumption required for the operation of the power plants at the project site in year y (MWh)	On-site measurements	Use calibrated electricity meters	Data monitored continuously and aggregated as appropriate, to calculate emissions reductions	The consistency of metered electricity generation should be cross-checked with receipts from electricity sales (if available) and the quantity of fuels fired (e.g. check whether the electricity generation divided by the quantity of fuels fired results in a reasonable efficiency that is comparable to previous years). $EG_{PJ,aux,y}$ shall include all electricity required for the operation of equipment related to the preparation, storage and transport of biomass (e.g. for mechanical treatment of the biomass, conveyor belts, driers, etc.) and electricity required for the operation of all power plants which are located at the project site and included in the project boundary (e.g. pumps, fans, cooling towers, instrumentation and control tools, etc.). If steam turbines are used for mechanical power generation in the baseline scenario and electric motors for the same purpose in the project scenario, the electricity used to run these electric motors shall be included in $EL_{PJ,aux,y}$

15.	$NCV_{BR,n,y}$	GJ/tons of dry matter	Net calorific value of biomass residue of category n in year *y* (GJ/ton on dry-basis)	On-site measurements	Measurements shall be carried out at reputed laboratories and according to relevant international standards. Measure the NCV on dry-basis	At least every six months, taking at least three samples for each measurement	Check the consistency of the measurements by comparing the measurement results with measurements from previous years, relevant data sources (e.g. values in the literature, values used in the national GHG inventory) and default values by the IPCC. If the measurement results differ significantly from previous measurements or other relevant data sources, conduct additional measurements. Ensure that the NCV is determined on the basis of dry biomass. Biogas should be included as appropriate if applicable (in which case convenient units such as GJ/m^3 should be used)
16.	$h_{LOW,y}$ $h_{HIGH,y}$	GJ/tons	$h_{LOW,y}$ = Specific enthalpy of the heat carrier at the process heat demand side (GJ/tons) $h_{HIGH,y}$ = Specific enthalpy of the heat carrier at the heat generator side (GJ/tons)	On-site measurements	The specific enthalpies should be determined based on the temperatures and, in case of superheated steam, the pressure. Steam tables or appropriate thermodynamic equations may be used to calculate the enthalpy as a function of temperature and pressure	Data monitored continuously and aggregated as appropriate, to calculate emissions reductions	The process heat demand side refers to where heat is finally used for heating purposes by end-users and the heat generator side refers to where heat is generated
17.	P_y	Use suitable units, as appropriate	Quantity of the main product of the production process (e.g. sugar cane, rice) produced in year *y* from plants operated at the project site	On-site measurements		Data aggregated as appropriate, to calculate emissions reductions	
18.	LOC_y	Hour	Operation time of the industrial facility using the process heat in year *y* (hour)	On-site measurements	Record and sum the hours of operation of the project activity facilities during year *y*		

Appendix 5. Risk management

Table A5.1. Risk management

Stage of climate project implementation	Description of risk	Probability of occurrence	Impact on the project	Impact period	Risk minimization methods	Implementation period
		1. low 2. medium 3. high	1. low 2. medium 3. high	1. Preparation period 2. 1-2 years after the implementation 3. 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			

Appendix 6. Recommended approach for calculation of the grid emission factor (emission factor for an electricity system)

1. Currently, there are no legislatively approved grid emission factors for greenhouse gases (GHG) in the Russian Federation.

2. If the initial data required to calculate the grid emission factor for the baseline and project scenarios are available, the climate project developer has the right to calculate it independently. In this case, it is recommended to use the Guidelines for the quantitative calculation of the volume of indirect energy emissions of greenhouse gases (Order No. 330 of the Ministry of Natural Resources and Environment dated 29.06.2017[1]) and the principles for calculating indirect energy emissions defined in GOST R ISO 14064-1-2021[2].

   To determine the grid emission factor, a regional method for calculation of indirect energy emissions is used, which reflects the average intensity of greenhouse gas emissions at facilities generating electrical and thermal energy consumed by the organization (Order No. 330 of the Ministry of Natural Resources and Environment).

   According to GOST R ISO 14064-1-2021, emissions from imported electricity must be calculated by the project developer using a location-based approach[3] by applying an emission factor that best characterizes the relevant electric power system, i.e. leased transmission line, local, regional or national grid average emission factor. The grid-averaged emission factors should refer to the emissions of the reporting year, if available, or otherwise the latest available year. Grid-averaged emission factors for imported electricity should be based on the average consumption pattern from the electric power system from which the electricity is consumed.

   Grid emission factors may also include other indirect emissions associated with electricity generation, such as transmission and distribution losses.

   The requirements and guidance described in ISO 14064-1-2021 for electricity also apply to consumed and transferred heat, steam, cooling air and compressed air.

   In case of energy from cogeneration facilities, it is necessary to use approaches to separate various forms of energy[4].

   Association "NP Market Council" and JSC "TSA" have developed a concept for calculating and publishing greenhouse gas emission factors for the energy system of the Russian Federation[5]. Based on the results of the peer review, independent international auditors issued an assurance certificate,

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[1] Order No. 330 of the Ministry of Natural Resources and Environment of the Russian Federation dated 29.06.2017 "On approval of guidelines for quantifying the volume of indirect energy emissions of greenhouse gases".

[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 30.09.2021).

[3] The location-based approach is a method for quantifying indirect energy emissions based on average emission factors from energy production for a given geographic location, including local, regional or national boundaries.

[4] For example, calculation of specific fuel consumption in accordance with the "Methodological Guidelines for the Distribution of the Specific Consumption of Reference Fuel in the Production of Electric and Thermal Energy in the Cogeneration Mode Used for Tariff Regulation in the Field of Heat Supply", legislatively approved by Order No. 952 of the Ministry of Energy of the Russian Federation dated 12.09.2016.

[5] The concept of calculation and publication of greenhouse gas emission factors for the energy system of the Russian Federation. URL: https://www.np-sr.ru/sites/default/files/koncepciya_kev.pdf .

and this concept received a validation report[6]. It is assumed that the implementation of this concept will lead to a more accurate calculation and publication of grid emission factors. The approaches outlined in the concept can also be used by the project developer to calculate the emission factor of the electric power system.

3. If it is impossible to calculate the grid emission factor on its own, the project developer can use grid emission factors from the following sources:

Source 1. In 2021, JSC "Trading System Administrator of Wholesale Electricity Market Transactions" launched (in test mode) an Internet resource that publishes the grid CO_2 emission factor for the first synchronous zone of the Russian Federation for various time periods (hour, day, month, year)[7].

Source 2. Emission factors of the International Energy Agency (IEA). The data are updated annually for the entire energy system of the regions of presence (including the Russian Federation) and reflects the average carbon intensity of electricity and heat generation[8].

Source 3. Climate Transparency Global Partnership develops G20 climate indicators. The agency publishes annual reports from the G20[9] countries, including the average energy emission factor.

4. Methods and approaches applied to the calculation of the grid emission factor should be documented and specified in the PDD. It is necessary to justify the chosen calculation methodology, disclose information about the source of the initial data used, transparently and accurately document your own procedure for calculating the grid emission factor, or describe the properties of the selected and applied grid emission factor.

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[6] As part of the validation procedure, a detailed verification of the Concept was carried out for its compliance with the requirements of the international standards in the field of accounting and reporting on greenhouse gas emissions (TÜV AUSTRIA). Based on the results of the audit, the Concept was recognized by international experts as complying with high international standards and best international practices for calculating energy system emission factors. URL: https://www.np-sr.ru/sites/default/files/zaklyuchenie_o_validacii_koncepcii.pdf.

[7] URL: https://www.atsenergo.ru/results/co2

[8] URL: https://www.iea.org/data-and-statistics/data-product/emissions-factors-2021

[9] URL: https://www.climate-transparency.org/g20-climate-performance/g20report2022#1531904804037-423d5c88-a7a7

Appendix 7. Recommended approach for calculation of the indirect energy emission factor for captive use and mini-grid

1. Calculation of the indirect energy emissions factor for captive use and mini-grid electricity consumption is carried out using the market approach (Order No. 330 of the Ministry of Natural Resources and Environment of Russia dated 29.06.2017[10]).

2. The market approach is used when the electricity consumed is received under bilateral contracts for the sale of electricity, signed in accordance with the rules of the wholesale electricity and capacity market and provisions on the operation of retail electricity markets[11]. Market factors of indirect energy emissions are indicated in sales contracts, in retail electricity markets contracts; or provided in certificates confirming the volume of electricity production at generating facilities using renewable energy sources, information about which is entered in the register[12]; or calculated based on the volumes of electricity received from specific external generating facilities in accordance with the terms of sales contracts, retail market contracts or certificates for the reporting period. Methodological guidelines for the calculation are set out in the Order No. 330 of the Ministry of Natural Resources and Environment of Russia dated 29.06.2017.

3. If the supplier of electricity under sales contracts, retail market contracts or certificates has several generating facilities[13], the market factor is determined only for the generating facility (or generating facilities), from which electricity is supplied to the consumer.

4. If the project activity consumes additional electrical energy that was not declared by sales contracts, retail market contracts or certificates (undeclared balance of electricity, i.e. the amount of electricity consumed in excess of the established contract and/or certificate(s)), the volume of the undeclared balance of electrical energy is determined based on the information received from external generating facilities located in the regional energy system. Thus, indirect energy emissions from the consumption of electricity received under contracts and/or certificates are calculated based on the market approach, and indirect emissions from the consumption of the undeclared balance of electricity – the location-based approach (see Appendix 6).

5. In the Russian Federation, there are generating facilities that are not connected to the Unified Energy System of Russia (Technologically Isolated Territorial Electric Power System, TITEPS[14]). In such cases, calculation of indirect energy emissions should be based on the individual emission factors of all generating facilities included in the TITEPS mini-grid (the Order No. 330 of the Ministry of Natural Resources and Environment of Russia dated 29.06.2017).

6. Market approach is not used to calculate indirect energy emissions from heat consumption. Thermal energy received from external generating facilities is evaluated using the location-based approach (Order No. 330 of the Ministry of Natural Resources and Environment of Russia dated 29.06.2017).

[10] Order No. 330 of the Ministry of Natural Resources and Environment of the Russian Federation dated 29.06.2017 "On approval of guidelines for quantifying the volume of indirect energy emissions of greenhouse gases".
[11] Federal Law No. 35-FZ "On the Electric Power Industry" dated 26.03.2003, as amended.
[12] Decree No. 117 of the Government of the Russian Federation "On some issues related to the certification of volumes of electrical energy produced at generating facilities operating on the use of renewable energy sources" dated 17.02.2014, as amended.
[13] For example, hydropower stations or thermal power stations.
[14] Technologically isolated territorial electric power system (TITEPS) is an electric power system located on the territory determined by the Government of the Russian Federation, which has no technological connection with the Unified Energy System of Russia (GOST R 57114-2016 Unified energy system and isolated operating energy systems. Electric power systems. Operational and dispatching management in the electric power industry and operational-technological management. Terms and definitions).

7. The project developer needs to ensure that the approaches and data used comply with the general requirements and guidance for the accounting of imported electricity consumed by the project activity set out in GOST R ISO 14064-1-2021[15](Appendix E).

8. The project developer needs to specify input data and data sources in the PDD, as well as the applied calculation methodology and methods used for the separation of different forms of energy (for example, in case of cogeneration, where applicable), and transparently and accurately document the procedure for calculating indirect energy emission factor based on market approach.

[15] 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).

Appendix 8. Emissions from solid waste disposal sites

1. This Appendix provides procedures to calculate baseline emissions of methane from solid waste disposed or prevented from disposal at a solid waste disposal site (SWDS).

2. This Appendix is based on CDM Tool 04 “Emissions from solid waste disposal sites” and provides a large overview of the calculation methodologies. For the parameters not defined in the Appendix and detailed calculations refer to the original tool.

3. For the purpose of this tool, the following definitions apply:

   (a) **Managed SWDS** is a SWDS that has controlled placement of waste (i.e. waste directed to specific deposition areas, a degree of control of scavenging and a degree of control of fires) and will include at least one of the following: (i) cover material; (ii) mechanical compacting; or (iii) levelling of the waste. In this Appendix, a SWDS that does not meet this definition is considered an unmanaged SWDS.

   (b) **Municipal solid waste (MSW)** is a heterogeneous mix of different solid waste types, usually collected by municipalities or other local authorities. MSW includes household waste, garden/park waste and commercial/institutional waste.

   (c) **Residual waste** is a solid waste type with largely homogenous properties. This includes, inter alia, material that remains after the waste is treated, e.g. anaerobic digestate and compost, and biomass residues (by-product, residue or waste stream from agriculture, forestry and related industries).

   (d) **Solid waste** is waste consisting primarily of solid materials[16].

   (e) **Solid waste disposal site (SWDS)** means designated areas intended as the final storage place for solid waste. Stockpiles are considered a SWDS if: (a) their volume to surface area ratio is 1.5 or larger; and (b) a visual inspection confirms that the material is exposed to anaerobic conditions (i.e. it has a low porosity and is moist).

   (f) **Stockpile** is a pile of solid waste (not buried below ground). Anaerobic conditions are not assured in a stockpile with low volume to surface area ratios (less than 1.5) because the waste may be exposed to higher aeration.

Table 1. Parameter

Parameter	SI Unit	Description
$BE_{CH4,SWDS,y}$	t CO_2e/yr	Baseline methane emissions occurring in year *y* generated from waste disposal at a SWDS during a time period ending in year *y* (where *y* is a period of 12 consecutive months)

4. The amount of methane generated from disposal of waste at the SWDS is calculated based on a first order decay (FOD) model. The model differentiates between the different types of waste *j* with respective constant decay rates (k_j) and fractions of degradable organic carbon (DOC_j).

5. The model calculates the methane generation occurring in year *y* (a period of 12 consecutive months) based on the waste streams of waste types *j* disposed in the SWDS over a

[16] GOST 56222-2014. Resources saving. Waste treatment. Material related terms and definitions.

specified time period.

6. In cases where at the SWDS methane is captured (e.g. due to safety regulations) and flared, combusted or used in another manner that prevents emissions of methane to the atmosphere, the emissions are adjusted for the fraction of methane captured (f_y).

7. The amount of methane generated from disposal of waste at the SWDS is calculated for year *y* ($BE_{CH4,SWDS,y}$) using equation (1). All data used in the equations should be documented transparently in the PDD or the monitoring reports.

8. The PDD should also clearly specify the time period (the consecutive years *x*), in which waste disposal is considered in the calculation.

9. The emissions are calculated as follows:

Equation (1)

$$BE_{CH4,SWDS,y} = \varphi_y \times (1 - f_y) \times GWP_{CH4} \times (1 - OX) \times \frac{16}{12} \times F \times DOC_{f,y} \times MCF_y \times \sum_{x=1}^{y} \sum_{j} (W_{j,x} \times DOC_J \times e^{-k_j \times (y-x)} \times (1 - e^{-k_j}))$$

Where:

$BE_{CH4,SWDS,y}$	=	Baseline methane emissions occurring in year *y* generated from waste disposal at a SWDS during a time period ending in year *y* (t CO_2e/yr)
x	=	Years in the time period in which waste is disposed at the SWDS, extending from the first year in the time period (*x* = 1) to year *y* (*x* = *y)*
y	=	Year of the crediting period for which methane emissions are calculated (*y* is a consecutive period of 12 months)
$DOC_{f,y}$	=	Fraction of degradable organic carbon (DOC) that decomposes under the specific conditions occurring in the SWDS for year *y* (weight fraction)
$W_{j,x}$	=	Amount of solid waste type *j* disposed or prevented from disposal in the SWDS in the year *x* (t)
φ_y	=	Model correction factor to account for model uncertainties for year *y*
f_y	=	Fraction of methane captured at the SWDS and flared, combusted or used in another manner that prevents the emissions of methane to the atmosphere in year *y*
GWP_{CH4}	=	Global Warming Potential of methane
OX	=	Oxidation factor (reflecting the amount of methane from SWDS that is oxidized in the soil or other material covering the waste)
F	=	Fraction of methane in the SWDS gas (volume fraction)
MCF_y	=	Methane correction factor for year *y*

DOC_j	=	Fraction of degradable organic carbon in the waste type *j* (weight fraction)
k	=	Decay rate for the waste type *j* (1 / yr)
j	=	Type of residual waste or types of waste in the MSW

10. Table 2 summarizes how the parameters required in this tool can be determined. This includes the use of default values, one-time measurements or monitoring throughout the crediting period.

Table 2. Overview of the options to determine parameters

Parameter	Application
φ_y	Baseline emissions: default values or project specific value estimated yearly
OX	Default value
F	Default value
$DOC_{f,y}$	In the case of residual waste estimated once
MCF_y	Monitored for SWDS with a water tableabove the bottom of the SWDS Default values (based on SWDS type) for SWDS without a water table above the bottom of the SWDS
k_j	Default values (based on waste type)
$W_{j,x}$	Calculated based on monitored data
DOC_j	Default values or waste specific value estimated once
f_y	Monitored

Determining the model correction factor (φ_y)

11. The model correction factor (φ_y) depends on the uncertainty of the parameters used in the FOD model. If baseline emissions are being calculated, the project participants may choose between the following two options to calculate φ_y.

Option 1: Use a default value

12. Use a default value: $\varphi_y = \varphi_{default}$, provided in Appendix 3.

Option 2: Determine φy based on specific situation of the project activity

13. Undertake an uncertainty analysis for the specific situation of the proposed project activity.The overall uncertainty of the determination of methane generation in year *y* (v_y) is calculated as follows:

Equation (2)

$$V_y = \sqrt{a^2 + b^2 + c^2 + d^2 + e^2 + g^2}$$

14. The factors a, b, c, d, e and g quantify the effect of the uncertainty of different parameters (listed in the second column of Table 3), used in the FOD model, on the overall uncertainty of the methane generation in year *y*. For each factor, the project participants shall select a value within the range provided in Table 3, following the instructions in the table, and justify their selection.

Table 3. Instructions for the selection of values for the factors a, b, c, d, e and g

Factor	Parameter	Lower value	Higher value	Instructions for selecting the factor
a	*W*	2%	10%	Use the lower value if solid waste is weighed using accurate weighbridges. Use the higher value if the amount of waste is estimated, such as from the depth and surface area of an existing SWDS
b	*DOCj*	5%	10%	Use the lower value if the DOC*j* is measured. Use the higher value if default values are used
c	*DOCf*	5%	15%	Use the lower value if more than 50 percent of the waste is rapidly degradable organic material or if the SWDS is located in a tropical climate. Otherwise use the higher value
d	*F*	0%	5%	Use the lower value if more than 50 percent of the waste is rapidly degradable organic material
e	*MCFy*	0%	50%	Use the lower value for managed SWDS. For unmanaged SWDS, use the higher value or determine the factor as 2/d, where d is the depth of the SWDS (in meters)
g	$e^{-k_j \times (y-x)} \times (1 - e^{-k_j})$	5%	20%	The uncertainty values provided express the uncertainty for the exponential term as a whole. Use the lower uncertainty value if residual waste is disposed at the SWDS and if the value of k is larger than 0.2 y^{-1})

15. φ_y is then calculated as follows:

$$\varphi_y = \frac{1}{(1 + V_y)}$$ Equation (3)

Determining the amounts of waste types j disposed in the SWDS

16. Where different waste types *j* are disposed or prevented from disposal in the SWDS, it is necessary to determine the amount of different waste types ($W_{j,x}$). In the case that only one type of waste is disposed (for example, in thecase of a residual waste), then $W_{j,x} = W_x$ and the following procedures do not need to be applied (e.g. waste sampling is not required).

17. Determine the amount of different waste types through sampling and calculate the mean from the samples either using equation (4) to determine the value of $W_{j,x}$:

$$W_{j,x} = W_x \times p_{j,x}$$ Equation (4)

Where:

$W_{j,x}$	=	Amount of solid waste type j disposed or prevented from disposal in the SWDS in the year *x* (t)
W_x	=	Total amount of solid waste disposed or prevented from disposal in the SWDS in year *x* (t)
$p_{j,x}$	=	Average fraction of the waste type *j* in the waste in year *x* (weight fraction)
j	=	Types of solid waste
x	=	Years in the time period for which waste is disposed at the SWDS, extending from the first year in the time period (*x* = 1) to year *y* (*x* = y)

18. The fraction of type *j* waste in the waste for year *x* or month *i* are calculated according to equation (5), as follows:

$$p_{j,x} = \frac{\sum_{n}^{Z_x} = 1\ P_{n,j,x}}{Z_x}$$ Equation (5)

Where:

$p_{j,x}$	=	Average fraction of type *j* waste in the waste in year *x* (weight fraction)
$p_{n,j,x}$	=	Fraction of type *j* waste in sample *n* collected during the year *x* (weight fraction)
Z_x	=	Number of samples collected during the year *x*
n	=	Samples collected in year *x*
j	=	Types of solid waste
x	=	Years in the time period for which waste is disposed at the SWDS, extending from the first year in the time period (*x* = 1) to year *y* (*x* = y)

Determining the fraction of DOC that decomposes in the SWDS ($DOC_{f,y}$)

19. If that the tool is applied to MSW, the project participants may choose to either apply a default value ($DOC_{f,y} = DOC_{f,default}$) or to determine $DOC_{f,y}$ based on measurements of the biochemical methane potential of the MSW (BMP_{MSW}), as follows:

$$DOC_{f,y} = 0.7 \times \frac{12}{16} \times \frac{BMP_{MSW}}{F \times \sum_j (p_{j,y} \times DOC_j)}$$ Equation (6)

Where:

$DOC_{f,y}$	=	Fraction of degradable organic carbon (DOC) that decomposes under the specific conditions occurring in the SWDS for year *y* (weight fraction)
BMP_{MSW}	=	Biochemical methane potential for the MSW disposed or prevented from disposal (t CH_4/t waste)
F	=	Fraction of methane in the SWDS gas (volume fraction)
DOC_j	=	Fraction of degradable organic carbon in type *j* waste (weight fraction)
$p_{j,y}$	=	Average fraction of type *j* waste in the waste in year *y* (weight fraction)
j	=	Types of solid waste in the MSW
y	=	Year of the crediting period for which methane emissions are calculated (*y* is a consecutive period of 12 months)

20. In the case that the tool is applied to a residual waste, then project participants shall determine $DOC_{f,y}$ based on measurements of the biochemical methane potentialof the residual waste type *j* (BMP_j), as follows:

$$DOC_{f,y} = 0.7 \times \frac{12}{16} \times \frac{BMP_j}{F \times DOC_j} \qquad \text{Equation (7)}$$

Where:

$DOC_{f,y}$	=	Fraction of degradable organic carbon (DOC) that decomposesunder the specific conditions occurring in the SWDS for year *y* (weight fraction)
BMP_j	=	Biochemical methane potential for the residual waste type *j* disposed or prevented from disposal (t CH_4/t waste)
F	=	Fraction of methane in the SWDS gas (volume fraction)
DOC_j	=	Fraction of degradable organic carbon in the waste type *j* (weight fraction)
j	=	Residual waste type applied to the tool
y	=	Year of the crediting period for which methane emissions arecalculated (*y* is a consecutive period of 12 months)

Procedure to determine the methane correction factor (MCF_y)

21. In case of a water table above the bottom of the SWDS (for example, due to using waste to fill inland water bodies, such as ponds, rivers or wetlands), the MCF should be determined as follows:

$$MCF_y = MAX\left\{(1 - \frac{2}{d_y}), \frac{h_{w,y}}{d_y}\right. \qquad \text{Equation (8)}$$

Where:

MCF_y	= Methane correction factor for year *y*
$h_{w,y}$	= Height of water table measured from the base of the SWDS (m)
d_y	= Depth of SWDS (m)

22. In other situations, the MCF should be selected as a default value ($MCF_y = MCF_{default}$).

Simplified approaches

23. For projects, which involve solely municipal solid waste, project proponent may use a simplified approach for the determination of baseline methane emissions. Two such approaches are available:

(a) no waste composition monitoring;

(b) reduced waste composition monitoring.

(a) No waste composition monitoring

24. In this approach, part of equation (1), which corresponds to the property of waste and climate zone, is replaced by default values, relieving the project proponents of the task of analyzing the composition of waste. The term, which may be replaced[17], has the unit of t CO_2/ton of dry waste and is:

$$(1 - \text{OX}) \times \frac{16}{12} \times F \times DOC_{f,y} \times \sum_{x=1}^{y} \sum_{j} DOC_j \times e^{-k_j \times (y-x)} \times (1 - e^{-k_j}) \qquad \text{Equation (9)}$$

25. Equation (1) is therefore simplified with only W_x as a monitoring parameter:

$$BE_{CH4,SWDS,y} = \varphi_y \times (1 - f_y) \times GWP_{CH4} \times \sum_{x=1}^{y} Default_x \times W_x \qquad \text{Equation (10)}$$

26. The value of $Default_x$ depends on the climate zone and on the year *x* since the disposal of the waste. The default values have been derived by an analysis of registered projects with verified waste compositions, and the default values are selected to ensure conservativeness of the resulting baseline emissions (using 95% confidence and 10% precision).

Table 1. $Default_x$ values for simplified procedure

[17] The following assumed values were used in the calculation: OX = 0.1; F = 0.5; DOC_f = 0.5; MCF = 1.

x	Tropical wet	Tropical dry	Boreal/ temperate wet	Boreal/temperate dry
1	0.005800	0.001856	0.003382	0.001399
2	0.004212	0.001724	0.002913	0.001325
3	0.003093	0.001601	0.002511	0.001254
4	0.002275	0.001487	0.002163	0.001188
5	0.001657	0.001381	0.001861	0.001125
6	0.001198	0.001281	0.001599	0.001065
7	0.000867	0.001189	0.001371	0.001008
8	0.000635	0.001103	0.001174	0.000954
9	0.000474	0.001024	0.001004	0.000904
10	0.000362	0.000950	0.000859	0.000855
11	0.000284	0.000881	0.000734	0.000810
12	0.000228	0.000817	0.000629	0.000766
13	0.000189	0.000757	0.000539	0.000725
14	0.000160	0.000702	0.000463	0.000687
15	0.000138	0.000651	0.000399	0.000650
16	0.000122	0.000603	0.000344	0.000615
17	0.000109	0.000559	0.000298	0.000582
18	0.000098	0.000518	0.000259	0.000551
19	0.000090	0.000480	0.000226	0.000521
20	0.000082	0.000445	0.000197	0.000493
21	0.000076	0.000413	0.000173	0.000467

(b) Reduced waste composition monitoring

27. In this approach, instead of monitoring the composition of the waste in accordance with waste types j, projects may monitor the total wet weight fraction of organic waste ($W_{org,y}$). Organic waste includes wood, paper, food waste, textiles and garden wastes. Similarly to the first approach, the term in equation 9 of the appendix is replaced.

28. Equation (1) is therefore simplified:

$$BE_{CH4,SWDS,y} = \varphi_y \times (1 - f_y) \times GWP_{CH4} \times \sum_{x=1}^{y} Default_{org,x} \times W_{org,x}$$ Equation (11)

29. The value of $Default_{org,x}$ depends on the climate zone. These values were derived by an analysis of registered CDM projects with verified waste compositions, and the $default_{org,x}$ values are selected to ensure conservativeness of the resulting baseline emissions (using 95% confidence and 10% precision).

Table 2. $Default_{org,x}$ values for simplified procedure

x	Tropical wet	Tropical dry	Boreal/ temperate wet	Boreal/temperate dry
1	0.008263	0.002715	0.004905	0.002000
2	0.006066	0.002516	0.004254	0.001891

3	0.004527	0.002330	0.003686	0.001788
4	0.003324	0.002156	0.003177	0.001691
5	0.002348	0.001995	0.002714	0.001599
6	0.001657	0.001845	0.002305	0.001511
7	0.001185	0.001706	0.001953	0.001429
8	0.000862	0.001577	0.001654	0.001351
9	0.000641	0.001458	0.001402	0.001277
10	0.000489	0.001347	0.001191	0.001207
11	0.000384	0.001246	0.001013	0.001141
12	0.000309	0.001152	0.000864	0.001079
13	0.000256	0.001065	0.000738	0.001020
14	0.000218	0.000985	0.000633	0.000964
15	0.000189	0.000911	0.000544	0.000911
16	0.000167	0.000842	0.000470	0.000862
17	0.000150	0.000779	0.000406	0.000815
18	0.000136	0.000721	0.000353	0.000770
19	0.000124	0.000668	0.000308	0.000728
20	0.000114	0.000618	0.000269	0.000689
21	0.000105	0.000572	0.000237	0.000651

Appendix 9. Assessment of the validity of the original/current baseline at the renewal of the crediting period

1. This appendix describes a procedure to be used to assess the validity of the original/current baseline at the renewal of the crediting period.

2. Assessment of the validity of the original/current baseline at the renewal of the crediting period consists of two steps.

3. Assess the validity of the current baseline for the next crediting period.

(a) Assess compliance of the current baseline with relevant mandatory national and/or sectoral policies. If the current baseline is not in compliance with the relevant mandatory national and/or sectoral policies, or if it cannot be demonstrated that the policies are systematically not enforced and that non-compliance with those policies is widespread in the country or region, the current baseline needs to be updated for the subsequent crediting period.

(b) Assess the impact of circumstances. If the new circumstances make a continued validity of the current baseline not plausible, the current baseline needs to be updated for the subsequent crediting period.

(c) Assess whether the continuation of use of the current baseline equipment or an investment is the most likely scenario for the crediting period for which renewal is requested. If the baseline scenario of the project activity is the continuation of use of the current equipment without any investment and the projects proponents or third party(ies) will undertake an investment later, but before the end of a crediting period, then the current baseline needs to be updated for that crediting period or the crediting of emission reductions should be limited to the period before the baseline equipment would cease its operation.

(d) Assessment of the validity of the data and parameters. If any of the data and parameters that were only determined at the start of the crediting period and not monitored during the crediting period are not valid anymore, the current baseline needs to be updated for the subsequent crediting period.

4. If the application of p. a, b, c and d confirmed that the current baseline as well as data and parameters are still valid for the subsequent crediting period, such baseline, data and parameters can be used for the renewed crediting period. Otherwise, proceed to Step 5.

5. Update the current baseline and the data and parameters.

6. This step is only applicable if any of the above p. *a, b, c* and/or *d* showed that the current baseline needs to be updated.

(a) Update the current baseline. Update the current baseline emissions for the subsequent crediting period, without reassessing the baseline scenario, based on the latest approved version of the methodology applicable to the project activity. The procedure should be applied in the context of the sectoral policies and circumstances that are applicable at the time of request for renewal of the crediting period.

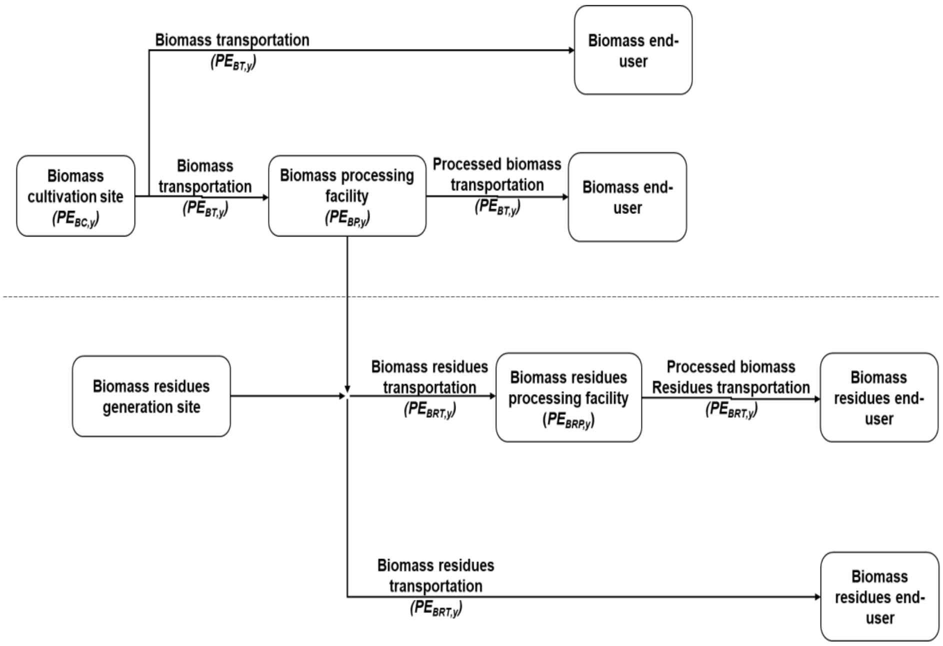
(b) Update the data and parameters. If the application of p. *d* showed that the data and/or parameter(s) that were only determined at the start of the crediting period and not monitored during the crediting period are not valid anymore, the project participants should update all applicable data and parameters.

Appendix 10. Project and leakage emissions from biomass

1. This appendix provides procedures to calculate project emissions and leakage that are relevant for project activities, which utilize biomass cultivated in dedicated plantations and/or biomass residues. The biomass and/or biomass residues may be used as either fuel or feedstock in the project activity.

2. Figure 1 below provides an overview of the project emission sources over the value chain of the biomass and biomass residues:

Figure 1. Illustration of project emission sources included in the appendix



3. Unless allowed by the methodology, only positive leakage, i.e. increased emissions outside the project boundary, can be accounted for under this appendix. If the result of the leakage calculation is negative, assume that the value equals zero.

4. For project activities which include biomass cultivation:

   (a) Biomass may be cultivated on cropland, agricultural land where only forage and/or perennial crops have been grown within the last 5 years, except for perennial woody cultivated plants planted within the last 15 years. Biomass harvests may be performed on grassland if no haying has occurred on these areas within the last 5 years. Wetlands, including drained wetlands, shall not be used as the project area. If cropland or grasslands have not been used for their intended purpose over the last 5 years, it is necessary to provide evidence that the woody vegetation on these lands (if any) does not meet the requirements of paragraph 1 of the Regulations on the peculiarities of the use, protection, conservation and reproduction of forests located on agricultural lands, approved by Resolution No. 1509 of the Government of the Russian Federation dated 21.09.2020, as amended by Resolution No. 1043 of the Government of the Russian Federation dated 08.06.2022.

   (b) The land in which biomass is cultivated:

(i) does not contain organic soils as defined in paragraph 7 (b);

(ii) is not subjected to flood irrigation;

(iii) does not contain forest nor contained forest since 31 December 1989.

5. Biomass can be collected on agricultural lands (dead biomass), forest lands (dead biomass), coastal ecosystems (dead biomass), lands of settlements (dead biomass), places of separate collection/sorting of organic waste, production and sale of food products, livestock farms. In case of biomass collection in forest, coastal, agrarian ecosystems and green urban areas, the collection should not exceed the minimum volume of dead organic material necessary for sustainable ecosystem functioning, taking into account the rates of biogeochemical cycles of basic elements and substances in a given ecosystem. The determination of this minimum volume should be made ex ante, scientifically justified and confirmed during project validation.

6. The appendix is also applicable if biomass residues are consumed in a project activity, and the biomass residues can be utilized after processing or without processing. These could be:

(a) procured by the project proponents; or

(b) obtained as a result of an agro-industrial process under the control of the project proponents.

7. For the purpose of this appendix, the following definitions apply:

(a) **Indirect land use change** is land-use change that may be induced on land areas not included in the project boundary as a result of shifting of pre-project activities.

(b) **Organic soil**: for the purpose of this methodology, soil is organic if it satisfies the requirements (i) and (ii), or (i) and (iii) below:

(i) Thickness of 10 cm or more. A horizon less than 20 cm thick must have 12 percent or more of organic carbon when mixed to a depth of 20 cm.

(ii) The soil is never saturated with water for more than a few days, and contains more than 20 percent (by weight) of organic carbon (about 35 percent of organic matter).

(iii) The soil is subject to water saturation episodes and contains either:

a. at least 12 percent (by weight) of organic carbon (about 20 percent oforganic matter) if it contains no clay; or

b. at least 18 percent (by weight) of organic carbon (about 30 percentof organic matter) if it contains 60 percent or more of clay; or

c. an intermediate, proportional amount of organic carbon for intermediate amounts of clay.

(c) **Pre-project activities** are the land use prior to the implementation of the project activity, considering both land use practices and the primary and final products of the practices. This includes, for example, grazing, cultivation of crops, agroforestry, collection of biomass.

(d) **Project region** is the area within a radius of 250 km around the project activity.

(e) **Stratum** is an area of land with uniform properties.

(f) **Wetlands** are areas of marsh, fen, peatland or water, whether natural or artificial, permanent or temporary, with water that is static or flowing, fresh, brackish or saline, including areas of marine water the depth of which at low tide does not exceed six meters. Wetlands may incorporate riparian and coastal zones adjacent to the wetlands, and islands or bodies of marine water deeper than six meters at low tide lying within the wetlands.

8. Project emissions involve emissions resulting from the cultivation of biomass, transportation of biomass, processing of biomass, transportation of biomass residues and processing of biomass residues.

9. Project emissions resulting from cultivation of biomass in a dedicated plantation in year *y* ($PE_{BC,y}$) are estimated as follows:

$$PE_{BC,y} = PE_{SOC,y} + PE_{SM.y} + PE_{BSH,EC,y} + PE_{BB,y}$$

Where:

$PE_{SOC,y}$	=	Project emissions resulting from loss of soil organic carbon in year *y* (t CO_2e)
$PE_{SM.y}$	=	Project emissions resulting from soil management in year *y* (t CO_2e)
$PE_{BSH,EC,y}$	=	Project emissions resulting from energy consumption (electricity and fuel) for biomass seeding and harvesting in year *y* (t CO_2e)
$PE_{BB,y}$	=	Project emissions resulting from clearance or burning of biomass, in year *y* (t CO_2e)

10. To estimate emissions resulting from loss of soil organic carbon in year *y* ($PE_{SOC,\ y}$), the areas of land are stratified according to:

(a) climate regions and soil types given in Table 1 of this appendix;

(b) land-use and land management activities on croplands given in Tables 2 and 3 at the end of this appendix; and

(c) land-use and land management activities on grasslands given in Table 4 at the end of this appendix. This also applies to abandoned land.

11. For each stratum of the areas of land, which is subjected to soil disturbance attributable to project activity and for which the total area disturbed is less than 10% of the area of the stratum, emissions resulting from loss of soil organic carbon may be assumed to be zero.

12. Subject to the provision of paragraph 11 above, emissions resulting from loss of soil organic carbon are estimated as follows:

$$PE_{SOC,y} = \max\left(\frac{44}{12} \times \frac{1.179}{T} \times \sum_{i} \Delta SOC_i, 0\right)$$

Where:

T	=	Length of the first crediting period of the project in years
ΔSOC_i	=	Loss of soil organic carbon in land stratum *i* (t C)
$\frac{44}{12}$	=	Factor for converting units from t C to t CO_2e; dimensionless
1.179	=	Factor to account for soil N_2O emissions associated with loss of soil organic carbon[1], dimensionless
i	=	Strata of the project areas of land, where biomass is cultivated

13. Loss of soil organic carbon in a stratum is estimated as follows:

$$\Delta SOC_i = 1.21 \times A_{SOC.i} \times SOC_{REF,i} \times \left(f_{LUB,i} \times f_{MGB,i} \times f_{INB,i} - f_{LUP,i} \times f_{MGP,i} \times f_{INP,i}\right)$$

Where:

$A_{SOC.i}$	=	Area of land stratum *i* (ha)
$SOC_{REF,i}$	=	Reference SOC stock applicable to land stratum *i* (t C/ha)
$f_{LUB,i}$	=	Relative stock change factor for land-use in the baseline in stratum *i*
$f_{MGB,i}$	=	Relative stock change factor for land management in the baseline in stratum *i*
$f_{INB,i}$	=	Relative stock change factor for input in the baseline in stratum *i*
$f_{LUP,i}$	=	Relative stock change factor for land-use in the project instratum *i*
$f_{MGP,i}$	=	Relative stock change factor for land management in the project instratum *i*
$f_{INP,i}$	=	Relative stock change factor for input in the project in stratum *i*
i	=	Strata of the project areas of land, where biomass is cultivated
1.21	=	Conservativeness factor accounting for the uncertainties in the values in Tables 2 to 4 of this appendix

14. The values of relative stock change factors shall be determined according to Tables 2 to 4 at the end of this appendix.

15. After the first crediting period of the project, the value of $PE_{SOC,y}$ shall be 0.

16. Project emissions resulting from soil management *n* year *y* ($PE_{SM,y}$) are estimated as follows:

$$PE_{SM,y} = PE_{SF,y} + PE_{SA,y}$$

Where:

$PE_{SF,y}$	=	Project emissions resulting from soil fertilization and management in year *y* (t CO_2e)
$PE_{SA,y}$	=	Project emissions resulting from soil amendment in year *y* (t CO_2e)

17. Project emissions resulting from soil fertilization and management in year *y* ($PE_{SF,y}$) are estimated

[1] Based on the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

as follows:

$$PE_{SF,y} = q_{N,y} \times A_{FTM,y} \times EF_{FT}$$

Where:

$q_{N,y}$	=	Rate of nitrogen applied in year *y* (t N/ha)
$A_{FTM,y}$	=	Area of land subjected to soil fertilization and management in year *y* (ha)
EF_{FT}	=	Aggregate emission factor for N_2O and CO_2 emissions resulting from production and application of nitrogen (t CO_2e/ (t N)). A default value of 11.29 t CO_2e/ (t N)[2] shall be used

18. Project emissions resulting from soil amendment (liming) in year y ($PE_{SA,y}$) are estimated as follows:

$$PE_{SA,y} = \sum_{i} q_{SA,y} \times A_{SA,i} \times EF_{SA,y}$$

Where:

$q_{SA,y}$	=	Rate of application of type *i* soil amendment agent in year *y* (t/ha)
$A_{SA,i}$	=	Area of land in which type *i* soil amendment agent is applied inyear *y* (ha)
$EF_{SA,y}$	=	Emission factor for CO_2 emissions from application of type *i* soil amendment agent (t CO_2e/t). Default values for limestone (0.12 t CO_2e/t)[3], dolomite (0.13 t CO_2e/t)[4] and urea (0.20 t CO_2e/t)[5]shall be used

19. Project emissions resulting from fuel and electricity consumption for biomass seeding and harvesting (e.g. fuel consumed by tractors and harvesters, and electricity consumed for irrigation water pumping) in year *y* ($PE_{BSH,\ EC,\ y}$) are estimated, unless otherwise required in the relevant methodology, by the equation below:

$$PE_{BSH,EC,y} = PE_{BSH,electricity,y} + PE_{BSH,fuel,y}$$

Where:

$PE_{BSH,electricity,y}$	=	Project emissions from the consumption of electricity for biomass seeding and harvesting in year *y* (t CO_2e)
$PE_{BSH,fuel,y}$	=	Project emissions from the consumption of fossil fuels for biomass seeding and harvesting in year *y* (t CO_2e)

20. The parameter $PE_{BSH,\ electricity,\ y}$ is estimated as follows:

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[2] Based on 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

[3] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Vol 4, Ch 11, Eq 11.12.

[4] Ibid.

[5] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Vol 4, Ch 11, Eq 11.13

$$PE_{BSH,elecrtricity,y} = \sum_j EC_{PJ.j.y} \times EF_{EF,j,y} \times \left(1 + TDL_{j,y}\right);$$

Where:

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

21. The parameter $PE_{BSH,\ fuel,\ y}$ corresponds to the parameter $PE_{FC,\ j,\ y}$ from Appendix 1.

22. Project emissions resulting from clearance or burning of biomass in year y ($PE_{BB,y}$) are estimated as follows:

$$PE_{BB,y} = \frac{44}{12} \times 0.47 \times \sum_i A_{FR,i,y} \times b_i \times (1.06 + R_i)$$

Where:

$\frac{44}{12}$	=	Factor for converting units from t C to t CO_2e, dimensionless
0.47	=	Default value of carbon fraction of biomass burnt,[6] dimensionless
1.06	=	Factor to account for non-CO_2 emissions from biomass clearance or burning[7]. If biomass is cleared without using open fire, this factor is assumed to be 1 (one)
$A_{FR,i,y}$	=	Area of stratum *i* of land subjected to clearance or fire in year *y* (ha)
b_i	=	Fuel biomass consumption per hectare in stratum *i* of land subjected to clearance or fire (t dry matter/ha)
R_i	=	Root-shoot ratio (i.e. ratio of below-ground biomass to above-ground biomass) for stratum *i* of land subjected to clearance or fire
R_i	=	Strata of the project areas of land, where biomass is cultivated

23. Project emissions resulting from transport of biomass ($PE_{BT,y}$) and biomass residues ($PE_{BRT,y}$) are determined separately taking into account the following transport routes:

(a) For biomass:

(i) If the biomass produced is utilized without further processing, the route shall include only the transport of the biomass between the biomass production site

[6] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Vol 4, Ch 4 Table 4.3.

[7] Based on the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

and the biomass utilization facility.

(ii) If the biomass is processed before being utilized, the routes shall include the transport between (i) the biomass production site and the biomass processing facility, and (ii) the biomass processing facility and the biomass utilization facility.

(b) For biomass residues:

(i) If the biomass residues are consumed without further processing, the route shall include only the transport of the biomass residues between the biomass processing facility or the biomass generation site and the biomass residues utilization facility.

(ii) If the biomass residues are processed before being utilized, the routes shall include the transport between (i) the biomass processing facility or the biomass generation site and the biomass residues processing facility, and (ii) the biomass residues processing facility and the biomass residues utilization facility.

24. The parameters $PE_{BT,y}$ and $PE_{BRT,y}$ are estimated as follows:

$$PE_{BT,y} = \sum_{f} D_{f,m} \times FR_{f,m} \times EF_{CO2,f} \times 10^{-6}$$

$$PE_{BRT,y} = \sum_{f} D_{f,m} \times FR_{f,m} \times EF_{CO2,f} \times 10^{-6}$$

$D_{f,m}$	=	Return trip distance between the origin and destination of freight transportation activity *f*
$FR_{f,m}$	=	Total mass of freight transported in freight transportation activity *f* in monitoring period *m* (t)
$EF_{CO2,f}$	=	Default CO_2 emission factor for freight transportation activity *f*, 245 for light vehicles and 129 for heavy vehicles (g CO2/t km)
j	=	Freight transportation activities conducted in the project activity

25. As an alternative to the monitoring of the parameters needed to calculate the emissions from the transportation, project proponents may apply a net-to-gross adjustment of 10%[8], i.e.multiply the

[8] Determined as the ratio between (i) the emissions to transport 1 ton of biomass and (ii) the emission reductions from the electricity generated by 1 ton of biomass, based on the following assumptions of a hypothetical project:

(a) The biomass is sourced from a distance of 200 km and the transport is made using heavy-duty vehicles. These assumptions are conservative since:

(i) 110 km is observed in monitoring reports of registered project activities as a typical distance of transport.

(ii) The transport of biomass is made using heavy-duty vehicles, which is the vehicle type with the higher specific emission factor of 129 gCO2/tkm).

(b) The type of biomass consumed is black liquor, the electricity is generated by a technology with 35% efficiency and is exported to a grid with an emission factor of 0.5 tCO_2/MWh. These assumptions are also conservative since:

(i) Black liquor is the type of biomass that has the lowest value of NCV among the types included in Table 1.2 of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (5.9 TJ/Gg).

(ii) The grid emission factor in non-Annex I countries currently reported is typically above 0.69 tCO_2/MWh (e.g.

emission reductions determined based on the applied methodology by 0.9 to determine the final amount of emission reductions that can be claimed.

26. Project emissions resulting from processing of biomass ($PE_{BP,y}$) and biomass residues ($PE_{BRP,y}$) are determined as based on the equations below:

$$PE_{BP,y} = PE_{BP,elecricity,y} + PE_{BP,fuel,y} + PE_{BP,CH4,y} + PE_{BP,COMP,y} + PE_{BP,AD,y} + PE_{BP,ww,y} + PE_{BP,additives,y}$$

$$PE_{BRP,y} = PE_{BRP,elecricity,y} + PE_{BRP,fuel,y} + PE_{BRP,CH4,y} + PE_{BRP,COMP,y} + PE_{BRP,AD,y} + PE_{BRP,ww,y} + PE_{BRP,additives,y}$$

Where:

$PE_{BP,elecricity,y}$	=	Project emissions resulting from the consumption of electricity due to thermo-chemical, biological and mechanical processing of the biomass in year *y* (t CO_2e)
$PE_{BRP,fuel,y}$	=	Project emissions resulting from the consumption of fossil fuels for thermo-chemical, biological and mechanical processing of the biomass in year *y* (t CO_2e)
$PE_{BP,CH4,y}$	=	Project methane emissions resulting from the decay of biomass under anaerobic conditions as a result of thermo-chemical, biological and mechanical processing in year *y* (t CO_2e)
$PE_{BP,COMP,y}$	=	Project emissions resulting from composting due to thermo-chemical, biological and mechanical processing of the biomass in year *y* (t CO_2e)
$PE_{BP,AD,y}$	=	Project emissions resulting from the anaerobic digester due to thermo-chemical, biological and mechanical processing of the biomass in year *y* (t CO_2e)
$PE_{BP,ww,y}$	=	Project emissions resulting from wastewater treatment due to thermo-chemical, biological and mechanical processing of the biomass in year *y* (t CO_2e)
$PE_{BP,additives,y}$	=	Project emissions resulting from the use of additives to process the biomass in year *y* (t CO_2e)
$PE_{BRP,elecricity,y}$	=	Project emissions resulting from the consumption of electricity due to thermo-chemical, biological and mechanical processing of the biomass residues in year *y* (t CO_2e)
$PE_{BRP,fuel,y}$	=	Project emissions resulting from the consumption of fossil fuels due to thermo-chemical, biological and mechanical processing of the biomass residues in year *y* (t CO_2e)

as observed from the IGES Database);

The emissions to transport 1 ton of biomass are determined by multiplying the distance travelled (200 km) by the emission factor of the heavy-duty vehicles to transport 1 ton of biomass (129 gCO_2/tkm, or 129 x 10-6 tCO_2/tkm), which is equal to 0.0258 tCO_2/t of biomass.

The emission reductions from the electricity generated by 1 ton of biomass are determined as the product between the energy released when burning one ton of black liquor (5.9 TJ/Gg, or 1.64 MWh/ton), the efficiency of the technology consuming the biomass (35%) and the grid emission factor (0.5 tCO_2/MWh), resulting in 0.287 tCO_2/t of biomass. This is further discounted by the emissions due to transportation of 1 ton of biomass determined above (0.0258 tCO_2/t of biomass) and the final result is equal to 0.261 tCO_2/t of biomass.

The ratio, therefore, equals to 0.0258 / 0.261, which is approximately 10%.

$PE_{BRP,CH4,y}$	=	Project methane missions resulting from the decay of biomass residues under anaerobic conditions due to thermo-chemical, biological and mechanical processing in year *y* (t CO_2e)
$PE_{BRP,COMP,y}$	=	Project emissions associated resulting from composting due to thermo-chemical, biological and mechanical processing of the biomass residues in year *y* (t CO_2e)
$PE_{BRP,AD,y}$	=	Project emissions resulting from the anaerobic digester due to thermo-chemical, biological and mechanical processing of the biomass residues in year *y* (t CO_2e)
$PE_{BRP,ww,y}$	=	Project emissions resulting from wastewater treatment due to thermo-chemical, biological and mechanical processing of the biomass residues in year *y* (t CO_2e)
$PE_{BRP,additives,y}$	=	Project emissions resulting from the use of additives to process the biomass residues in year *y* (t CO_2e)

27. Emissions resulting from the electricity consumption due to thermo-chemical, biological and mechanical processing of the biomass and biomass residues are determined based on paragraph 20.

28. Emissions resulting from the fuel consumption due to thermo-chemical, biological and mechanical processing of the biomass and biomass residues are determined based on the provisions of Appendix 1, where the parameters $PE_{BP,\,fuel,\,y}$ and $PE_{BRP,\,fuel,\,y}$ correspond to $PE_{FC,\,j,\,y}$.

29. Emissions of methane from the decay of biomass under anaerobic conditions as a result of thermo-chemical, biological and mechanical processing of the biomass and biomass residues are determined based on the provisions of Appendix 9, where the parameters $PE_{BP,\,CH4,\,y}$ and $PE_{BRP,\,CH4,\,y}$ correspond to $PE_{CH4,\,SWDS,\,y}$.

30. Emissions from the composting as a result of thermo-chemical, biological and mechanical processing of the biomass and biomass residues ($PE_{BP,\,COMP,\,y}$ and $PE_{BRP,\,COMP,\,y}$) are estimated as follows:

$$PE_{BP,COMP,y} = PE_{EC,y} + PE_{FC,y} + PE_{CH4,y} + PE_{N2O,y} + PE_{RO,y}$$

Where:

$PE_{EC,y}$	=	Project emissions from electricity consumption associated with composting in year *y* (t CO_2/yr)[9]
$PE_{FC,y}$	=	Project emissions from fossil fuel consumption associated with composting in year *y* (t CO_2/yr)[10]
$PE_{CH4,y}$	=	Project emissions of methane from the composting process in year *y* (t CO2e/yr)
$PE_{N2O,y}$	=	Project emissions of nitrous oxide from the composting process in year *y* (t CO_2e/yr)
$PE_{RO,y}$	=	Project emissions of methane from run-off wastewater associated with co-composting in year *y* (t CO_2e/yr)

[9] Estimated as $PE_{BSH,\,electricity,\,y}$ in paragraph 20 where the project emission source *j* is composting.

[10] Corresponds to the parameter $PE_{FC,j,y}$ of Appendix 1, where the project emission source *j* is composting.

31. Project emissions of methane from the composting process in year y ($PE_{CH4,\, y}$) are estimated as follows:

$$PE_{CH4,y} = Q_y \times 0.002 \times GWP_{CH4}$$

Where:

Q_y	=	Quantity of waste composted in year y (t / yr)
0.002	=	Default emission factor of methane per ton of waste composted valid for year y (t CH_4/ t)
GWP_{CH4}	=	Global Warming Potential of CH_4 (t CO_2e / t CH_4)

32. Project emissions of nitrous oxide from the composting process in year y ($PE_{N2O\,,y}$) are estimated as follows:

$$PE_{N2O,y} = Q_y \times 0.0002 \times GWP_{N2O}$$

Where:

Q_y	=	Quantity of waste composted in year y (t / yr)
0.0002	=	Default emission factor of nitrous oxide per ton of waste composted valid for year y (t N_2O / t)
GWP_{N2O}	=	Global Warming Potential of N_2O (t CO_2e / t N_2O)

33. Project emissions of methane from run-off wastewater associated with co-composting in year y ($PE_{RO,\, y}$) are calculated only for the case of co-composting. Moreover, if run-off wastewater is collected and re-circulated to the composting process, $PE_{RO,\, y}$ is assumed to be zero (for example, this is the case for the tunnel co-composting technology). Otherwise, $PE_{RO,\, y}$ is calculated based on the quantity and chemical oxygen demand (COD) of run-off wastewater as follows:

$$PE_{RO,y} = Q_{COD,y} \times B_{0,ww} \times MCF_{ww,treatment} \times 1.12 \times GWP_{CH4}$$

Where:

$Q_{COD,y}$	=	Quantity of COD of the run-off wastewater from the co-composting installation in year y (t COD / yr)
$B_{0,ww}$	=	Default methane producing capacity of the run-off wastewater (t CH_4/ t COD)[11]
$MCF_{ww,treatment}$	=	Default methane correction factor for the wastewater treatment system where the run-off wastewater is treated[12]
1.12	=	Default model correction factor to account for model uncertainties of methane emissions from run-off wastewater
GWP_{CH4}	=	Global warming potential for methane valid for the relevant commitment period (t CO_2/t CH_4)

34. Project participants may choose between two options to calculate $Q_{COD,y}$ based on monitoring the quantity and COD of the run-off wastewater or the quantity and COD of the wastewater co-composted:

[11] Assumed 0.25 based on IPCC 2006 Guidelines for National Greenhouse Gas Inventories.

[12] Default factor is given in Table 5 at the end of this appendix.

(a) In this option, $Q_{COD,y}$ is determined as follows:

$$Q_{COD,y} = Q_{RO,y} \times COD_{RO,y}$$

Where:

$Q_{RO,y}$	=	Volume of run-off wastewater from the co-composting installation in year *y* (m^3/ yr)
$COD_{RO,y}$	=	Average COD of the run-off wastewater from the co-composting installation valid for year *y* (t COD/ m^3)

(b) In this option, $Q_{COD,y}$ is estimated using a default factor and monitoring the quantity and COD of the wastewater co-composted.

$$Q_{COD,y} = Q_{wastewater,y} \times COD_{wastewater,y} \times 0.02$$

Where:

$Q_{wastewater,y}$	=	Volume of wastewater co-composted in year *y* (m^3/ yr)
$COD_{wastewater,y}$	=	Average COD of the wastewater co-composted valid for year y (t COD / m^3)
0.02	=	Default factor for the ratio of the amount of COD in run-off wastewater and wastewater co-composted

35. Emissions from the anaerobic digester due to thermo-chemical, biological and mechanical processing of the biomass ($PE_{BP,AD,y}$) and biomass residues ($PE_{BRP,AD,y}$) are estimated as follows:

$$PE_{BP/BRP,AD,y} = PE_{EC,y} + PE_{FC,y} + PE_{AD,CH4,y} + PE_{flare,y}$$

Where:

$PE_{EC,y}$	=	Project emissions from electricity consumption associated with the anaerobic digester in year *y* (t CO_2e)[13]
$PE_{FC,y}$	=	Project emissions from fossil fuel consumption associated with the anaerobic digester in year *y* (t CO_2e)[14]
$PE_{AD,CH4,y}$	=	Project emissions of methane from the anaerobic digester in year *y* (t CO_2e)
$PE_{flare,y}$	=	Project emissions from flaring of biogas in year *y* (t CO_2e)

36. Project emissions of methane from the anaerobic digester include emissions during maintenance of the digester, physical leaks through the roof and side walls, and release through safety valves due to excess pressure in the digester. These emissions are calculated using a default emission factor as follows:

$$PE_{AD,CH4,y} = Q_{CH4,y} \times EF_{CH4,default} \times GWP_{CH4}$$

Where:

$Q_{CH4,y}$	=	Quantity of methane produced in the anaerobic digester in year *y* (t CH_4)
$EF_{CH4,default}$	=	Default emission factor for the fraction of CH_4 produced that leaks from

[13] Estimated as $PE_{BSH,electricity,y}$ in paragraph 20 where the project emission source j is the total electricity consumption associated with the anaerobic digestion facility.

[14] Corresponds to the parameter $PE_{FC,j,y}$ of Appendix 1, where the project emission source j is fossil fuel consumption associated with the anaerobic digestion facility (not including fossil fuels consumed for transportation of feed material and digestate or any other on-site transportation).

the anaerobic digester (fraction)[15]

GWP_{CH4} = Global Warming Potential of CH_4 (t CO_2e / t CH_4)

37. The quantity of methane produced in the anaerobic digester ($Q_{CH4,y}$) is estimated by the flow of the gaseous stream (biogas collected from the digester) that should be measured on an hourly basis or with a higher frequency; and then accumulated for the year *y*. Please note that units need to be converted to tons. This parameter may be determined using three options.

(a) Option 1 for flow of gaseous stream measured on wet basis, and volumetric fraction measured on dry or wet basis. It is necessary to demonstrate that the gaseous stream is dry by either measuring the moisture content of the gaseous stream and demonstrating that it is less than or equal to 0.05 kg H_2O/m^3 of dry gas or by demonstrating that the temperature of the gaseous stream is less than 60ºC (333.15 K) at the flow measurement point.

$$F_{i,t} = V_{t,db} \times v_{i,t,db} \times \rho_{i,t}$$

With:

$$\rho_{i,t} = \frac{P_t \times MM_i}{R_u \times T_t}$$

$$V_{t,db} = {M_{t,tb}}/{\rho_{t,db}}$$

$$\rho_{t,db} = \frac{P_t \times MM_{t,db}}{R_u \times T_t}$$

$$MM_{t,db} = \sum_k \left(v_{k,t,db} \times MM_k\right)$$

Where:

$F_{i,t}$	=	Mass flow of greenhouse gas *i* in the gaseous stream in time interval *t* (kg gas/h)
$V_{t,db}$	=	Volumetric flow of the gaseous stream in time interval *t* on a dry basis (m^3 dry gas/h)
$v_{i,t,db}$	=	Volumetric fraction of greenhouse gas *i* in the gaseous stream in a time interval *t* on a dry basis (m^3 gas i/m^3 dry gas)
$\rho_{i,t}$	=	Density of greenhouse gas *i* in the gaseous stream in time interval *t* (kg gas i/m^3 gas *i*)
P_t	=	Density of greenhouse gas *i* in the gaseous stream in time interval *t* (kg gas i/m^3 gas *i*)

[15] Use the default value corresponding to the type of digester used in the project activity. The digester type shall be identified by manufacturer information. If this is not possible, then the factor 0.1 shall be applied (upper range of the IPCC values):

- 0.028: Digesters with steel or lined concrete or fiberglass digesters and a gas holding system (egg shaped digesters) and monolithic construction;
- 0.05: UASB type digesters, floating gas holders with no external water seal;
- 0.10: Digesters with unlined concrete/ferrocement/brick masonry arched type gas holding section; monolithic fixed dome digesters, covered anaerobic lagoon.

MM_i	=	Molecular mass of greenhouse gas *i* (kg/kmol)
R_u	=	Universal ideal gases constant (Pa.m^3 /kmol. K)
T_t	=	Temperature of the gaseous stream in time interval *t* (K)
$M_{t,tb}$	=	Mass flow of the gaseous stream in time interval *t* on a dry basis (kg/h)
$\rho_{t,db}$	=	Density of the gaseous stream in time interval *t* on a dry basis (kg dry gas/m^3 dry gas)
$MM_{t,db}$	=	Molecular mass of the gaseous stream in a time interval *t* on a dry basis (kg dry gas/kmol dry gas)
$\upsilon_{k,t,db}$	=	Volumetric fraction of gas *k* in the gaseous stream in time interval *t* on a dry basis (m^3 gas *k*/m^3 dry gas)
MM_k	=	Molecular mass of gas *k* (kg/kmol)
k	=	All gases, except H2O, contained in the gaseous stream

(b) Option 2 for flow of gaseous stream measured on wet basis, and volumetric fraction measured or dry basis.

$$F_{i,t} = V_{t,db} \times \upsilon_{i,t,db} \times \rho_{i,t}$$

With:

$$\rho_{i,t} = \frac{P_t \times MM_i}{R_u \times T_t}$$

$$V_{t,db} = {M_{t,tb}}/{\rho_{t,db}}$$

$$M_{t,db} = {M_{t,wb}}/{\left(1 + m_{H2O,t,db}\right)}$$

$$m_{H2O,t,db} = \frac{C_{H2O,t,db,n}}{10^6 \times \rho_{t,db,n}}$$

$$\rho_{t,db,n} = \frac{P_n \times MM_{t,db}}{R_u \times T_n}$$

$$MM_{t,db} = \sum_k \left(\upsilon_{k,t,db} \times MM_k\right)$$

Where:

$F_{i,t}$	=	Mass flow of greenhouse gas *i* in the gaseous stream in time interval *t* (kg gas/h)
$V_{t,db}$	=	Volumetric flow of the gaseous stream in time interval *t* on a dry basis (m^3 dry gas/h)
$\upsilon_{i,t,db}$	=	Volumetric fraction of greenhouse gas *i* in the gaseous stream in a time interval *t* on a dry basis (m^3 gas *i*/m^3 dry gas)

$\rho_{i,t}$	=	Density of greenhouse gas *i* in the gaseous stream in time interval *t* (kg gas *i*/m^3 gas *i*)
P_t	=	Density of greenhouse gas *i* in the gaseous stream in time interval *t* (kg gas *i*/m^3 gas *i*)
MM_i	=	Molecular mass of greenhouse gas *i* (kg/kmol)
R_u	=	Universal ideal gases constant (Pa.m^3 /kmol. K)
T_t	=	Temperature of the gaseous stream in time interval *t* (K)
$M_{t,tb}$	=	Mass flow of the gaseous stream in time interval *t* on a dry basis (kg/h)
$\rho_{t,db}$	=	Density of the gaseous stream in time interval *t* on a dry basis (kg dry gas/m^3 dry gas)
$M_{t,wb}$	=	Mass flow of the gaseous stream in time interval *t* on a wet basis (kg/h)
$m_{H2O,t,db}$	=	Absolute humidity of H_2O in the gaseous stream in a time interval *t* on a dry basis (kg H_2O/kg dry gas)
$C_{H2O,t,db,n}$	=	Moisture content of the gaseous stream in time interval *t* on a dry basis at normal conditions (mg H_2O/m^3 dry gas)
$\rho_{t,db,n}$	=	Density of the gaseous stream in time interval *t* on a dry basis at normal conditions (kg dry gas/m^3 dry gas)
P_n	=	Absolute pressure at normal conditions (Pa)
T_n	=	Temperature at normal conditions (K)
$MM_{t,db}$	=	Molecular mass of the gaseous stream in a time interval *t* on a dry basis (kg dry gas/kmol dry gas)
$\upsilon_{k,t,db}$	=	Volumetric fraction of gas *k* in the gaseous stream in time interval *t* on a dry basis (m^3 gas k/m^3 dry gas)
MM_k	=	Molecular mass of gas *k* (kg/kmol)
k	=	All gases, except H2O, contained in the gaseous stream

(c) Option 3 for flow of gaseous stream measured on wet basis and volumetric fraction measured on wet basis.

$$F_{i,t} = V_{t,wb,n} \times \upsilon_{i,t,wb} \times \rho_{i,n}$$

With:

$$\rho_{i,n} = \frac{P_n \times MM_i}{R_u \times T_n}$$

$$V_{t,wb,n} = {}^{M_{t,wb}}/_{\rho_{t,wb,n}}$$

$$\rho_{t,wb,n} = \frac{P_n \times MM_{t,wb}}{R_u \times T_n}$$

$$MM_{t,wb} = \sum_k \left(v_{k,t,wb} \times MM_k\right)$$

Where:

$F_{i,t}$	=	Mass flow of greenhouse gas *i* in the gaseous stream in time interval *t* (kg gas/h)
$V_{t,wb,n}$	=	Volumetric flow of the gaseous stream in time interval *t* on a wet basis at normal conditions (m^3 wet gas/h)
$v_{i,t,wb}$	=	Volumetric fraction of greenhouse gas *i* in the gaseous stream in time interval *t* on a wet basis (m^3 gas *i*/m^3 wet gas)
$\rho_{i,n}$	=	Density of greenhouse gas *i* in the gaseous stream at normal conditions (kg gas *i*/m^3 wet gas *i*)
P_n	=	Absolute pressure at normal conditions (Pa)
MM_i	=	Molecular mass of greenhouse gas *i* (kg/kmol)
R_u	=	Universal ideal gases constant (Pa.m^3 /kmol. K)
T_n	=	Temperature at normal conditions (K)
$M_{t,wb}$	=	Mass flow of the gaseous stream in time interval *t* on a wet basis (kg/h)
$\rho_{t,wb,n}$	=	Density of the gaseous stream in time interval *t* on a wet basis at normal conditions (kg wet gas/m^3 wet gas)
$MM_{t,wb}$	=	Molecular mass of the gaseous stream in time interval *t* on a wet basis (kg wet gas/kmol wet gas)
$v_{k,t,wb}$	=	Volumetric fraction of gas *k* in the gaseous stream in time interval *t* on a wet basis (m^3 gas k/m^3 wet gas)
MM_k	=	Molecular mass of gas *k* (kg/kmol)
k	=	All gases contained in the gaseous stream

38. If the project activity includes flaring of biogas, project emissions from flaring of biogas in year *y* ($PE_{flare,y}$) are estimated based on CDM TOOL06 Project emissions on flaring.

39. Project emissions from the wastewater treatment anaerobic digester due to thermo-chemical, biological and mechanical processing of biomass in year *y* ($PE_{BP,ww,y}$) and project emissions from the wastewater treatment anaerobic digester due to thermos-chemical, biological and mechanical processing of biomass residues in year *y* ($PE_{BRP,ww,y}$) shall be estimated in cases where wastewater originating from the processing of the biomass and biomass residues is (partly) treated under anaerobic conditions and where methane from the wastewater is not captured and flared or combusted. Project emissions from wastewater are estimated as follows:

$$PE_{BP,ww,y} = GWP_{CH4} \times V_{BP,ww,y} \times COD_{BP,ww,y} \times B_{o,WW} \times MCF_{BP,ww}$$

$$PE_{BRP,ww,y} = GWP_{CH4} \times V_{BRP,ww,y} \times COD_{BRP,ww,y} \times B_{o,WW} \times MCF_{BRP,ww}$$

Where:

GWP_{CH4}	=	Global warming potential for methane valid for the relevant commitment period (t CO_2/t CH_4)
$V_{BP,ww,y}$	=	Quantity of wastewater generated from the processing of biomassin year *y* (m^3)
$COD_{BP,ww,y}$	=	Average chemical oxygen demand of the wastewater generated from the processing of biomass in year *y* (t COD/m^3)
$B_{o,WW}$	=	Methane generation potential of the wastewater (t CH_4/t COD)
$MCF_{BP,ww}$	=	Methane correction factor for the treatment of wastewater generated from the processing of biomass in year *y* (ratio)
$V_{BRP,ww,y}$	=	Quantity of wastewater generated from the processing of biomass residues in year *y* (m^3)
$COD_{BRP,ww,y}$	=	Average chemical oxygen demand of the wastewater generated from the processing of biomass residues in year *y* (t COD/m^3)
$B_{o,WW}$	=	Methane generation potential of the wastewater (t CH_4/t COD)
$MCF_{BRP,ww}$	=	Methane conversion factor for the treatment of wastewater generated from the processing of biomass residues in year *y* (ratio)

40. Project emissions from the use of additives to process biomass in year *y* ($PE_{BP,additives,y}$) and project emissions from the use of additives to process biomass residues in year *y* ($PE_{BRP,additives,y}$) are estimated as follows:

$$PE_{BP,additives,y} = PE_{BP,additives,transport,y} + PE_{BP,additives,electricity,y} + PE_{BP,additives,FF,y}$$

$$PE_{BRP,additives,y} = PE_{BRP,additives,transport,y} + PE_{BRP,additives,electricity,y} + PE_{BRP,additives,FF,y}$$

Where:

$PE_{BP,additives,transport,y}$	=	Project emissions from the transportation of the additives from the production site to the biomass processing facility (t CO_2)
$PE_{BP,additives,electricity,y}$	=	Project emissions from the consumption of electricity to produce the additives used by the biomass processing facility (t CO_2)
$PE_{BP,additives,FF,y}$	=	Project emissions from the consumption of fossil fuels to produce the additives used by the biomass processing facility (t CO_2)
$PE_{BRP,additives,transport,y}$	=	Project emissions from the transportation of the additives from the production site to the biomass residues processing facility (t CO_2)
$PE_{BRP,additives,electricity,y}$	=	Project emissions from the consumption of electricity to produce the additives used by the biomass residues processing facility (t CO_2)

$PE_{BRP,additives,FF,y}$	=	Project emissions from the consumption of fossil fuels to produce the additives used by the biomass residues processing facility (t CO_2)

41. $PE_{BP,\ additives,\ transport,\ y}$ and $PE_{BRP,\ additives,\ transport,\ y}$ are determined following the provisions from paragraph 24.

42. Project emissions resulting from the electricity consumed to produce the additives are determined based on paragraph 20.

43. Project emissions resulting from the fuel consumed to produce the additives are determined are determined based on the provisions of Appendix 1, where the parameters $PE_{BP,\ additives,\ fuel,\ y}$ and $PE_{BRP,\ additives,\ fuel,\ y}$ correspond to $PE_{FC,\ j,\ y}$.

44. As an alternative to the monitoring of the parameters needed to calculate $PE_{BP,\ additives,\ y}$ and $PE_{BRP,\ additives,\ y}$, project proponents may apply the following options:

    (a) If the ratio between the additive consumed and the biomass or biomass residue processed (mass or volume basis) is below or equal to 2%, these emission sources may be neglected.

    (b) If the ratio between the additive consumed and the biomass or biomass residue processed (mass or volume basis) is above 2% and below or equal to 10%, only the emissions from the consumption of electricity and fuel to produce the additives may be accounted for. Project proponents may determine these emission sources based on literature such as peer reviewed studies.

    (c) If the ratio between the additive consumed and the biomass or biomass residue processed (mass or volume basis) is above 10%, emissions from both the consumption of electricity and fuel to produce the additives and to transport the additives shall be accounted for. Project proponents may determine these emission sources based on literature such as peer reviewed studies.

45. Leakage may occur outside the project boundary and may involve emissions due to shift of pre-project activities, diversion of biomass residues from other applications and due to processing and transportation of biomass residues outside the project boundary.

46. Leakage due to shift of pre-project activities resulting from cultivation of biomass in a dedicated plantation in year *y* ($LE_{BC,y}$) may occur only if the project activity utilizes biomass cultivated in a dedicated plantation. Project proponents are advised to avoid pre-project activities from being shifted outside the project boundary, to avoid indirect land use changes as a result of the project activity. Rather, project proponents are encouraged to include in the project boundary the land in which the pre-project activities will take place after the project implementation.

47. No leakage due to shift of pre-project activities occurs if one of the following two conditions applies:

    (a) The plantation area was or would have been abandoned land prior to the implementation of the project activity.

    (b) The plantation area was used prior to the implementation of the project activity but the pre-project land use of the plantation area will be accommodated for, providing at least the same level of service during the project activity, within the land area included in the project boundary. The project area may be expanded to accommodate for this condition. This could be achieved, inter alia, in the following ways:

(i) at least the same number of cattle as prior to the implementation of the project activity will continue being grazed during the project activity within the land area included in project boundary;

(ii) due to more efficient farming practice, the pre-project crops can be grown on a smaller area, which is included in the land area included in the project boundary, to achieve the same level of annual production of crops, freeing land for the dedicated plantation;

(iii) settlements are not removed from the land area included in the project boundary.

48. Project participants should assess the possibility of leakage from the displacement of activities or people by monitoring the following indicators:

(a) percentage of families/households of the community involved in or affected by the project activity displaced (from within to outside of the project boundary) due to the project activity;

(b) percentage of total production of the main product (e.g. meat, corn) within the project boundary displaced due to the cultivation of biomass.

49. No shift of pre-project activities is allowed.

50. Leakage due to diversion of biomass residues from other applications in year *y* ($LE_{BR,Div,y}$) may occur in project activities which utilize biomass residues. It quantifies leakage due to diversion of biomass residues to the project to be used as either fuel or feedstock. These biomass residues could have been used outside the project boundary in competing applications, and due to the implementation of the project activity these competing application might be forced to use inputs, which are not carbon neutral.

51. The alternative scenario for the "use", in the absence of the project activity, of biomass residues that will be used in the underlying project activity shall include:

(a) B1: The biomass residues are dumped or left to decay mainly under aerobic conditions. This applies, for example, to dumping and decay of biomass residues on fields.

(b) B2: The biomass residues are dumped or left to decay under clearly anaerobic conditions. This applies, for example, to landfills, which are deeper than five meters.This does not apply to biomass residues that are stock-piled or left to decay on fields.

(c) B3: The biomass residues are burnt in an uncontrolled manner without utilizing them for energy purposes.

(d) B4: The biomass residues are used for energy or non-energy applications, or the primary source of the biomass residues and/or their fate cannot be clearly identified.[16]

52. Project proponents may choose to combine some or all relevant biomass types into one category when determining the fate of biomass residues, and treat the combined types as one, for instance in the biomass availability determination. These combinations shall be

[16] For example, this scenario can be used if biomass residues are purchased from a market, or biomass residues retailers, or if processed biomass is purchased from biomass processing plants, which are not included in the project boundary.

documented transparently in the PDD and remain consistent throughout the crediting period.

53. When defining plausible and credible alternative scenarios for the use of biomass residues, the guidance below shall be followed:

(a) If the biomass residues processing (drying, pelletization, shredding, briquetting, etc.) is not included in the project boundary, the processed biomass obtained from that plant should be considered as B4 above.

(b) The alternative scenario for the categories of biomass residues identified according to paragraphs 51 and 52 above should be defined separately, covering the whole amount of biomass residues supposed to be used in the project activity during the crediting period.

(c) A category of biomass residues is defined by three attributes: (1) its type or types (i.e. bagasse, rice husks, empty fruit bunches, etc.); (2) its source (e.g. produced on-site, obtained from an identified biomass residues producer, obtained from a biomass residues market, etc.); and (3) its alternative scenario in the absence of the project activity (scenarios B1 to B4 as in paragraph 51 above).

(d) Explain and document transparently in the PDD what quantities of which biomass residues categories are used in which installation(s) under the project activity and what their alternative scenario is.

(e) For biomass residues categories for which scenarios B1, B2 or B3 are deemed a plausible alternative scenario, the following procedures should be applied for the combined amount of biomass identified:

(iv) Demonstrate that there is an abundant surplus of the biomass residue in the project region which is not utilized. For this purpose, demonstrate that the total quantity of that type of biomass residues annually available in the project region is at least 25 percent larger than the quantity of biomass residues which is utilized annually in the project region (e.g. for energy generation or as feedstock), including the project facility.

(v) Demonstrate for the sites from where biomass residues are sourced that the biomass residues have not been collected or utilized (e.g. as fuel, fertilizer or feedstock) but have been dumped and left to decay, land-filled, left in the field to decay after harvest,[17] or burnt without energy generation (e.g. field burning). This approach is only applicable to biomass residues categories for which project participants can clearly identify the site from where the biomass residues are sourced.

(vi) In case surplus of biomass residues in the project region cannot be demonstrated, the alternative use of the biomass shall be considered unknown (B4) and result in leakage emissions.

54. If during the crediting period new categories of biomass residues of the type B1, B2 or B3are used in the project activity which were not listed at the validation stage, for example, due to new sources of biomass residues, the alternative scenario for those types of biomass residues should be assessed using the procedures outlined in this appendix for each new category of

[17] Project proponents shall demonstrate the fraction of biomass which exceeds the function of refertilizing the soil, as only this part of the biomass may be considered unutilized.

biomass residues.

55. The main potential source of leakage due to biomass residues is an increase in emissions from fossil fuel combustion or other sources due to diversion of biomass residues from other uses to the project plant as a result of the project activity. The alternative scenario for biomass residues for which this potential leakage is relevant is B4.

56. The actual leakage emissions in each of these cases may differ significantly and depend on the specific situation of each project activity. For that reason, a simplified approach is used in this appendix: it is assumed that an equivalent amount of fossil fuels, on energy basis, would be used if biomass residues are diverted from other users, no matter what the use of biomass residues would be in the alternative scenario.

57. Therefore, for the categories of biomass residues whose alternative scenario has been identified as B4, project participants shall calculate leakage emissions as follows:

$$LE_{BR,Div,y} = EF_{CO2,LE} \times \sum_{n} BR_{PJ,n,y} \times NCV_{n,y}$$

Where:

$LE_{BR,Div,y}$	=	Leakage emissions due to the diversion of biomass residues from other applications in year *y* (t CO2e)
$EF_{CO2,LE}$	=	CO_2 emission factor of the most carbon intensive fossil fuel used in the country (t CO2/GJ)
$BR_{PJ,n,y}$	=	Quantity of biomass residues of category *n* used in facilities which are located at the project site and included in the project boundary in year *y* (tons on dry basis)
$NCV_{n,y}$	=	Net calorific value of the biomass residues of category *n* in year *y* (GJ/ton of dry matter)
n	=	Categories of biomass residues for which B4 has been identified as the alternative scenario

58. The determination of $BR_{PJ,n,y}$ shall be based on the monitored amounts of biomass residues used in the facilities included in the project boundary.

59. If the transportation of biomass residues takes place outside the project boundary, leakage due to the transportation of biomass residues outside of the project boundary in year *y* ($LE_{BT,y}$) is defined similarly to the provisions of paragraph 24.

60. If processing of biomass residues occurs outside the project boundary, leakage due to processing of biomass residues outside the project boundary in year *y* is estimated as in paragraph 25:

(a) The parameter $PE_{BRP,\ electricity,\ y}$ is determined according to paragraph 20, where $EC_{PJ.j.y}$ corresponds to net increase in electricity consumption in year *y* as a result of leakage[18].

(b) The parameter $PE_{BRP,\ fuel,\ y}$ corresponds to $PE_{FC,\ j,\ y}$ from Appendix 1.

[18] A net increase of electricity consumption outside the project boundary as a result of the project activity should be reflected in a positive value. If electricity consumption decreases as a result of the project activity, net increase in electricity consumption should be assumed to be zero.

(c) The parameter $PE_{BRP,\,CH4,\,y}$ corresponds to $LE_{CH4,\,SWDS,\,y}$ from the CDM TOOL06 Project emissions from flaring.

(d) The parameter $PE_{BRP,\,COMP,\,y}$ corresponds to $LE_{COMP,\,y}$ from the CDM TOOL13 Project and leakage emissions from composting.

(e) The parameter $PE_{BRP,\,AD,\,y}$, corresponds to $LE_{AD,\,y}$ from the CDM TOOL14 Project and leakage emissions from anaerobic digesters.

Tables. Default values

Table 1. Default reference SOC stocks (SOC_{REF}) for mineral soils (t C/ha in 0–30 cm depth)[19]

Climate region	HAC soils[20]	LAC soils[21]	Sandy soils[22]	Spodic soils[23]	Volcanic soils[24]	Wetland soils[25]
Polar, moist/dry	59	NA	27	NA	NA	NA
Boreal, moist/dry	63	NA	10	117	20	116
Cold temperate, dry	43	33	13	NA	20	87
Cold temperate, moist	81	76	51	128	136	128
Warm temperate, dry	24	19	10	NA	84	74
Warm temperate, moist	64	55	36	143	138	135
Tropical, dry	21	19	9	NA	50	22
Tropical, moist	40	38	27	NA	70	68
Tropical, wet	60	52	46	NA	77	49
Tropical, montane	51	44	52	NA	96	82

Table 2. Relative stock change factors for different management activities on cropland[26]

Factor type	Level	Temperature regime	Moisture regime	Factor value	Description and criteria
Land use (f_{LU})	Long-term cultivated	Cool temperate/ boreal	Dry	0.77	Area has been continuously managed for crops for more than 50 years
			Moist	0.70	
		Warm temperate	Dry	0.76	
			Moist	0.69	
		Tropical	Dry	0.92	
			Moist/Wet	0.83	
		Temperate/ boreal and tropical	Dry	0.93	Represents temporary set aside of annually cropland (e.g.,
			Moist/Wet	0.82	

[19] 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Table 2.3 (updated).

[20] Soils with high activity clay (HAC) minerals are lightly to moderately weathered soils, which are dominated by 2:1 silicate clay minerals (in the World Reference Base for Soil Resources (WRB) classification these include Leptosols, Vertisols, Kastanozems, Chernozems, Phaeozems, Luvisols, Alisols, Albeluvisols, Solonetz, Calcisols, Gypsisols, Umbrisols, Cambisols, Regosols).

[21] Soils with low activity clay (LAC) minerals are highly weathered soils, dominated by 1:1 clay minerals and amorphous iron and aluminium oxides (in WRB classification includes Acrisols, Lixisols, Nitisols, Ferralsols, Durisols).

[22] Includes all soils (regardless of taxonomic classification) having >70 per cent sand and <8 per cent clay, based on standard textural analyses (in WRB classification includes Arenosols).

[23] Soils exhibiting strong podzolization (in WRB classification includes Podzols).

[24] Soils derived from volcanic ash with allophanic mineralogy (in WRB classification, Andosols).

[25] Soils with restricted drainage leading to periodic flooding and anaerobic conditions (in WRB classification, Gleysols).

[26] Adapted from 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,Volume 4, Table 5.5 (updated).

Land use (f_{LU})	Set aside (< 20 yrs)	Tropical montane	n/a	0.88	conservation reserves) or other idle cropland that has been revegetated with perennial grasses
Management (f_{MG})	Full tillage	All	Dry and Moist/Wet	1.00	Substantial soil disturbance with full inversion and/or frequent (within year)tillage operations. At planting time, little (e.g. <30%) of the surface is covered by residues
Management (f_{MG})	Reduced tillage	Cool Temperate/ Boreal	Dry	0.98	Primary and/or secondary tillage but with reduced soil disturbance (usually shallow and without full soil inversion). Normally leaves surface with >30% coverage by residues at planting
			Moist	1.04	
		Tropical	Dry	0.99	
			Moist/Wet	1.04	
		Warm Temperate	Dry	0.99	
			Moist/Wet	1.04	
Management (f_{MG})	No-tillage	Cool Temperate/ Boreal	Dry	1.03	Direct seeding withoutprimary tillage, with only minimal soil disturbance in the seeding zone. Herbicides are typically used forweed control
			Moist	1.09	
		Tropical	Dry	1.04	
			Moist/Wet	1.10	
		Warm temperate	Dry	1.04	
			Moist/Wet	1.10	

Table 3. Relative stock change factors for different levels of nutrient input on cropland[27]

Factor type	Level	Temperature regime	Moisture regime	Factor value	Description and criteria
Input (f_{IN})	Low	Temperate/ Boreal	Dry	0.95	There is removal of residues (via collection or burning), or frequent bare-fallowing, or production of crops yielding low residues (e.g. vegetables, tobacco, cotton), or no mineral fertilization or N-fixing crops
			Moist	0.92	
		Tropical	Dry	0.95	
			Moist/ Wet	0.92	
		Tropical montane	n/a	0.94	

[27] Ibid.

Input (f_{IN})	Medium	All	Dry and Moist/ Wet	1.00	All crop residues are returned to the field. If residues are removed, supplemental organic matter (e.g. manure) is added. Additionally, mineral fertilization or N-fixing crop rotation is practiced
Input (f_{IN})	High without manure	Temperate/ Boreal and Tropical	Dry	1.04	Represents significantly greater crop residue inputs over medium C input cropping systems due to additional practices, such as production of high residue yielding crops, use of green manures, cover crops, improved vegetated fallows, irrigation, frequent use of perennial grasses in annual crop rotations, but without manure applied
			Moist/ Wet	1.11	
		Tropical Montane	n/a	1.08	
Input (f_{IN})	High with manure	Temperate/ Boreal and Tropical	Dry	1.37	Represents significantly higher C input over medium C input cropping systems due to an additional practice of regular addition of animal manure
		-	Moist /Wet	1.44	
		Tropical Montane	n/a	1.41	

Table 4. Relative stock change factors (f_{LU}, f_{MG}, *and* f_{IN}) for grassland management[28]

Factor type	**Level**	**Climate regime**	**Factor value**	**Description**
Land use (f_{LU})	All	All	1.00	All permanent grassland is assigned a land-use factor of 1
Management (f_{MG})	Non-degraded grassland	All	1.00	Non-degraded and sustainably managed grassland, but without significant management improvements
Management (f_{MG})	High intensity grazing	All	0.90	High intensity grazing systems (or cutting and removal of vegetation) with shifts in vegetation composition and possibly productivity but not

[28] Adapted from 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,Volume 4, Table 6.2 (updated).

				severely degraded
Management (f_{MG})	Severely degraded	All	0.70	Implies major long-term loss of productivity and vegetation cover, due to severe mechanical damage to the vegetation and/or severe soil erosion
Management (f_{MG})	Improved grasslands	Temperate/ Boreal	1.14	Represents grassland which is sustainably managed with moderate grazing pressure and that receives at least one improvement (e.g. fertilization, species improvement, irrigation)
		Tropical	1.17	
		Tropical Montane	1.16	
Input (f_{IN}) (applied only to improved grassland)	Medium	All	1.00	Improved grassland where no additional management inputs have been used
	High	All	1.11	Improved grassland where one or more additional management inputs/improvements have been used (beyond that required to be classified as improved grassland)

Table 5. IPCC default values for $MCF_{ww,treatment}$[29]

Use the default values below corresponding to the type of wastewater treatment system. If this is not possible, as a conservative estimation, waste water treatment can be assumed to take place under completely anaerobic conditions, where $MCF_{ww,\ treatment}$ equals 1.

Type of wastewater treatment and discharge pathway or system	**MCF value**
Discharge of wastewater to sea, river or lake	0.1
Aerobic treatment, well managed	0.0
Aerobic treatment, poorly managed or overloaded	0.33
Anaerobic digester for sludge without methane recovery	0.8
Anaerobic reactor without methane recovery	0.8

[29] Adapted from Default values from chapter 6 of volume 5. Waste in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories

Anaerobic shallow lagoon (depth less than 2 meters)	0.2
Anaerobic deep lagoon (depth more than 2 meters)	0.8
Septic system	0.5

Appendix 11. Determining the baseline efficiency of thermal or electric energy generation systems

1. The tool describes various procedures to determine the baseline efficiency of an energy generation system, for the purpose of estimating baseline emissions. The tool may be used in case of project activities that improve the energy efficiency of an existing system through retrofits or replacement of the existing system by a new system[30].

2. The tool provides different procedures to determine the baseline efficiency of the energy generation system: either a) a load-efficiency function is determined which establishes the efficiency as a function of the operating load of the system, or b) the efficiency is determined conservatively as a constant value.

3. This tool is applicable to energy generation systems that:

   (a) generate only electricity (and no thermal energy); or

   (b) produce only thermal energy (and no electricity); or

   (c) produce both electricity and thermal energy (cogeneration).

4. Also, the following conditions apply:

   (a) The tool is applicable to waste heat recovery systems to calculate efficiency values using options (A) to (E) as provided in paragraph 5 below.

   (b) The tool can be applied only if load is the main operating parameter that influences the efficiency of the energy generation system. For cogeneration systems, the heat to power ratio may also be considered a main operating parameter.

5. Project participants may use one of the following options to estimate the efficiency of the energy generation system:

   (a) Option A: Use the manufacturer's load-efficiency function.

   (b) Option B: Establish a load-efficiency function based on measurements and a regression analysis.

   (c) Option C: Establish the efficiency based on historical data and a regression analysis.

   (d) Option D: Use the manufacturer's efficiency values.

   (e) Option E: Determine the efficiency based on measurements and use a conservative value.

   (f) Option F: Use a default value.

6. Options (A) to (E) are applicable only to energy generation systems that use a single fuel type and fuel mix including waste energy. In case of fuel mix, the efficiency of the energy generating equipment is calculated based on the fuel with the highest share in terms of calorific value in a monitoring year.

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[30] The Appendix is based on CDM TOOL09 "Determining the baseline efficiency of thermal or electric energy generation systems" (Version 03). Use the original methodology where necessary.

7. Project participants should document which option is used to establish the efficiency of the relevant system, including, in the case of options (B), (C) or (E), the type of measuring equipment used, details of how the measurements were carried out, and the measurement results.

8. For cogeneration projects, project participants shall also document and justify the choice of heat to power ratio used in the measurements.

9. Option A: Use the manufacturer's load-efficiency function

10. This option cannot be applied to determine a constant efficiency. The option can be used if:

(a) the manufacturer of the energy generation system provided load-efficiency functions or performance curves for the system at the time of installation; and

(b) if these functions or curves clearly show the efficiency of the system at all applicable loads and for the relevant range of operational conditions[31]; and

(c) the functions or curves are consistent with the equipment/system characteristics; and

(d) if no retrofitting was done on the system prior to the implementation of the project activity that could have increased its efficiency.

11. The load-efficiency function of the energy generation system is derived from the manufacturer's function or curves, whereby each load point should have a corresponding efficiency for the relevant operating conditions (e.g. pressure and temperature of the steam).

12. In the case of performance curves, project participants may either derive a mathematical function from the curve or develop a table with efficiency vs. load values. The mathematical function or the table should closely represent the manufacturer's performance curves.

13. If the manufacturer supplies a mathematical relationship, this relationship can be used directly to derive the baseline efficiency of the energy generation system for the relevant operating conditions (e.g. pressure and temperature of the steam).

14. This option is conservative because the actual efficiency of the energy generation system is generally lower than the efficiency at the time of installation, due to ageing and deterioration of the system, unless the system is retrofitted during its service.

15. Option B: Establish a load-efficiency function based on measurements and a regression analysis

16. Establish the load-efficiency function by conducting efficiency tests on the energy generation system[32] and applying a regression analysis to the test results. The efficiency tests shall be conducted following the guidance provided in relevant national/international standards[33], preferably using direct methods. All measurements shall be conducted immediately after scheduled preventive maintenance has been undertaken and under favorable operation conditions[34]. During

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[31] This option cannot be used if the manufacturer provided efficiency values only at discrete load points. Project participants may consider Option D in this case.

[32] Tests shall be conducted before implementation of retrofits that are part of the project activity.

[33] National/International Standards provide detailed procedures, methods, guidance and/or recommendations for system operation conditions, test conditions, recording of measurements, permissible variations in measurements, instrumentation, uncertainty management, etc. during performance/acceptance tests.

[34] Favorable operation conditions are optimal operation conditions, representative or favorable ambient conditions for the best efficiency of the energy generation system, including temperature and humidity, etc.

the measurement campaign, the load should be varied over the whole operational range or the rated capacity of the energy generation system. The efficiency of the system should then be determined at different steady-state conditions. Document the monitoring procedures and results transparently. The tests shall be conducted by an independent entity such as the equipment supplier, sectoral experts/consultants etc. The results of the efficiency tests shall be validated.

17. Efficiency determination tests shall be conducted for the entire system as a whole including auxiliary equipment, such as the fuel conditioning system, preheating systems, etc. All energy inputs and outputs, such as the feed water supply or energy losses through blow down losses, shall be taken into consideration. Measurements shall be done for the complete system using calibrated equipment as required by the relevant national/international standards.

18. For the tests, two successive load points in the load range shall have an increment of at least 5% of the system's rated capacity. All efficiency tests shall be conducted for a predetermined discrete time interval as specified in standards. All tests shall have the same duration.

19. Each efficiency test provides a pair of data, i.e. (1) the load of the system and (2) the efficiency of system at that particular load. Based on the data collected at all load points, the load-efficiency function shall be established using a regression analysis. Project participants should choose the most suitable regression[35] model such as linear, polynomial etc. following the general guidance given below:

(a) Measure efficiency of the energy generation system at different load points as described above.

(b) Run a scatter plot to determine the degree of the model. Identify the potential outliers to be filtered or re-run the test at that level to confirm the outlier. The fitting of higher-order polynomials of an independent variable with a mean not equal to zero can create complex multi-collinearity problems. Specifically, the polynomials will be highly correlated due to the mean of the primary independent variable. The correct sample size is critical to ensure a good representative curve is established. Take into account that polynomial models cannot be used for extrapolation.

(c) Determine the coefficient of the equation using any methodology but taking into account the recommendations in (b) above.

20. The model should display:

(i) An ANOVA[8] (Analysis of Variance) table showing the regression and residual sum of squares and the significance.

(ii) The coefficients table showing the significance, these must be lower than 0.05.

(iii) Run a confirmatory data analysis, using the null hypothesis test to cover the entire population and allow forecasting for only the range of sample data.

(iv) Use α = probability (Reject Ho/Ho TRUE), a 0.05 value is recommended to assure the statistical significance.

[35] For using regression analysis, necessary safeguards in order to ensure conservativeness and rigor of the fitted regression model should be used. In the process of fitting the regression, assumptions and requirements for regression models should be considered e.g. testing for multicolinearity. It is recommended that project participants use the standard software to run the regression analysis and determine the standard error.

21. The resultant load-efficiency function derived using regression model shall be adjusted for uncertainty in a conservative manner, by considering the upper bound values of the range at 95% confidence level at the load point where efficiency is to be derived.

22. Option C: Establish the efficiency function based on historical data and a regression analysis

23. This option can be used to determine a load-efficiency function or a constant efficiency.

24. The following conditions apply:

(a) In the case where the tool is used to establish a load-efficiency function, this option can only be used if measured data on the load and other parameters that are required to establish the efficiency of the system are available on an hourly basis (or a shorter time period) for the most recent year prior to the implementation of the project activity.

(b) In the case that the tool is used to establish a constant efficiency, this option can only be used if annual data on the efficiency of the energy generation system is available for the most recent three years prior to the implementation of the project activity.

(c) No retrofitting was done during the period, for which historical data is used, that could have increased the efficiency of the energy generation system. The historical data shall be the actual measured data such as flow, pressure, temperature, fuel consumption, energy outputs, etc. as applicable (e.g. from plant operational log books).

25. If the tool is used to establish a constant efficiency, the highest annual efficiency from the most recent three years should be chosen.

26. If the tool is used to establish a load-efficiency function, a regression analysis should be applied, following the guidance given under option b) above, using the historical data from the most recent year instead of conducting measurements on the system. The data pairs for load and efficiency should be used for the time interval at which they are available (one hour or, if available, for a shorter time interval).

27. Project participants shall document the complete data set used to establish the efficiency function.

28. Option D: Use the manufacturer's efficiency values

29. This option can be used to determine a constant efficiency.

30. The following conditions apply:

(a) If the manufacturer does not provide full load-efficiency functions or performance curves (if these functions are provided, Option A applies) but only the maximum efficiency at the optimal operating conditions.

(b) No retrofitting was done prior to implementation of the project that could have increased the efficiency of the energy system.

31. If these conditions are met, the efficiency provided by the manufacturer can be used as a conservative approach.

32. Option E: Determine the efficiency based on measurements and use a conservative value

33. This option can be used to determine a constant efficiency. Under this option, the efficiency of the energy generation system shall be measured based on performance tests conducted before the implementation of the project activity following national/international standards, at discrete loads

within the operation range or over the entire rated capacity, preferably using direct methods (i.e. dividing the net output by the sum of all inputs).

34. For tests, two successive load points in the load range shall have an increment of at least 5% of the system's rated capacity. At each load point, one set of measurements shall be conducted. All efficiency tests shall be conducted for the same predetermined discrete time interval as specified in standards and witnessed by an independent party (e.g. the system manufacturer, a technical consultant etc.).

35. All measurements shall be conducted immediately after scheduled preventive maintenance has been undertaken and under favorable operation conditions (optimal operating conditions, representative or favorable ambient conditions for the best efficiency of the energy generation system, including temperature and humidity, etc.). During the measurement campaign, the load is varied over the whole operation range and the efficiency of the energy generation system is determined for different steady-state load levels. Document the measurement procedures and results transparently. A minimum of 10 measurements shall be taken at different loads in the full operation range or rated capacity and among the measurements, the highest efficiency shall be considered as a conservative approach.

36. Tests shall be conducted for the entire system including auxiliary equipment, such as the fuel conditioning system, preheating systems, etc. All energy inputs and outputs, such as the feed water supply or energy losses through blow down losses, shall be taken into consideration. Measurements shall be done using calibrated equipment as required by the relevant national/international standards.

37. Alternatively, if the efficiency test was conducted as part of concluding a previous retrofit activity or energy audits, or performance evaluation of the equipment, within 3 years prior to the implementation of the project activity, and if the measurements and efficiency determination has already been verified and certified by an independent party, project participants may use the same data without conducting a new measurement campaign. This alternative is not applicable where a retrofit to increase the energy efficiency was done.

38. Project participants shall justify and document the chosen optimal operating conditions.

39. Option F: Use a default value

40. This option can be used to determine a constant efficiency. Project participants may use the default values for the applicable technology from the appendix as constant efficiency.

41. Default efficiency factors

Table 11.1. Default efficiency factor for thermal applications

Technology of the energy generation system	Default efficiency
Natural gas fired boiler (w/o condenser)	92%
Oil fired boilers adapted as Natural gas fired boiler (w/o condenser)	87%
Oil fired boiler	90%
Biomass fired boiler (on dry biomass basis)	85%
Coal fired boiler	90%
Other	100%

Table 11.2. Default efficiency factor for power plants with installed capacity more than 1MW[36]

Generation technology	Commissioning year		
	y≤2000	**2000<y≥2012**	**y>2012**
Coal			
Subcritical	37%	39%	39%
Supercritical	-	45%	45%
Ultra-supercritical	-	50%	50%
IGCC	-	50%	50%
FB	35.5%	-	-
CFB	36.5%	40%	43%
PFB	-	41.5%	45%
Natural gas			
Reciprocal gas engine	33%	40%	48%
Open cycle gas turbine	30%	39%	44%
Combined cycle gas turbine	46%	60%	62%
Oil			
Steam turbine	37.5%	39%	44%
Reciprocal engine	33%	40%	48%
Biomass[37]			
IGCC	42%		
Other	35%		
Cogeneration[38]			
Steam turbine	83%		
Gas turbine	83%		
Reciprocal engine	89%		
Mircoturbine (up to 500kW)	78%		

Table 11.3. Default efficiency for power plants with installed capacity up to 1000 kW

	Nominal capacity of power plants (CAP, in kW)						
Generation Technology	**CAP≤10**	**10<CAP ≤50**	**50<CAP ≤100**	**100<CAP ≤200**	**200<CAP ≤400**	**400<CAP ≤1000**	
Reciprocal engine system (e.g. diesel-, fueloil-, gas-	28%	33%	35%	37%	39%	42%	

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[36] Main sources for values are IEA Energy technology perspective publication 2010 to 2017, IEA, Projected costs of generating electricity, 2015 and IEA, World Energy Outlook, 2018.

[37] Biomass calorific value is measured on dry basis. Maximum of 1% on energy basis fossil fuel co-firing is allowed, including start-up fuel. Main sources of values are IEA, Energy technology perspective, 2017, IEA, Projected costs of generating electricity, 2015 and IEA, World Energy Outlook, 2018.

[38] The values are the overall efficiency, for electric efficiency, use the power-only default values. Main source for cogeneration values: Implementing EPA's Clean Power Plan: A Menu of Options <http://www.4cleanair.org/NACAA_Menu_of_Options> and IEA, Energy technology perspective, 2017, IEA, Projected costs of generating electricity, 2015 and IEA, World Energy Outlook, 2018.

engines)[39]							
Gas turbine systems[40]	28%	32%	34%	35%	37%	40%	
Small boiler/steam/turbine system	7%	7%	7%	7%	7%	7%	

[39] Based on diesel consumption data available at https://www.dieselserviceandsupply.com/Diesel_Fuel_Consumption.aspx.
[40] Refer to footnote 6 and Implementing EPA's Clean Power Plan: A Menu of Options http://www.4cleanair.org/NACAA_Menu_of_Options.