# Draft revision to the approved baseline and monitoring methodology AM0107

## "New natural gas based cogeneration plant"

## I. SOURCE, DEFINITIONS AND APPLICABILITY

### Sources

This baseline and monitoring methodology is based on elements from the following proposed new methodology:

- NM0356 "New natural gas based combined heat and power plant" prepared by Sino Carbon Innovation and Investment Co., Ltd, and Beijing Energy Investment Holding Co., Ltd., Beijing Jingneng Clean Energy Corperation Limited, Beijing Jingqiao thermal power Co., Ltd., Beijing Energy Gaoantun gas-fire cogeneration Co., Ltd.

This methodology also refers to the latest approved versions of the following tools:

- "Tool to calculate project or leakage $CO_2$ emissions from fossil fuel combustion";
- "Tool to determine the remaining lifetime of equipment";
- "Tool to determine the baseline efficiency of thermal or electric energy generation systems";
- "Tool to calculate the emission factor for an electricity system";
- "Combined tool to identify the baseline scenario and demonstrate additionality";
- "Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period".

For more information regarding the proposed new methodology and the tools as well as their consideration by the Executive Board (hereinafter referred to as the Board) of the clean development mechanism (CDM) please refer to <http://cdm.unfccc.int/methodologies/PAmethodologies/index.html>.

### Selected approach from paragraph 48 of the CDM modalities and procedures

"Existing actual or historical emissions, as applicable"

or

"Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment".

### Definitions

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

**Cogeneration plant.** Cogeneration plant is a power-and-heat plant in which at least one heat engine simultaneously generates both heat and power.

**Heat.** Heat is useful thermal energy that is generated in a heat generation facility (e.g. a boiler, a cogeneration plant, thermal solar panels, etc.) and transferred to a heat carrier (e.g. liquids, gases, steam, etc.) for utilization in thermal applications and processes, including electric 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 facility. For example, in case of a boiler it refers to the difference of the enthalpy of the steam generated in the boiler and the enthalpy of the feed water and, if applicable, any condensate return.

**Heat generation facility**. The facility which generates useful heat, a heat generation facility can be boilers, cogeneration plants, thermal solar panels etc.

**Heat network**. The spatial extent of the heat generation facility that are physically connected through heating pipelines to the project activity and that can be dispatched without significant transmission constraints.

**Natural gas** is a gas which consist primarily methane and is generated from: (i) natural gas fields (non-associated gas), (ii) associated gas found in oil fields, or (iii) gas captured from landfills. It may be blended up to 1% on a volume basis with gas from other sources, such as, *inter alia*, biogas generated in bio-digesters, gas from coal mines, gas which is gasified from solid fossil fuels, etc.[1]

**New cogeneration plant.** Newly constructed cogeneration plant with no operational history.

## Applicability

This methodology applies to project activities that install a new cogeneration plant that use natural gas as fuel, supplies electricity to an electric power grid and supplies heat to an existing or newly created heat network.

The methodology is applicable under the following conditions:

(a) The geographical/physical boundaries of the electric power grid and heat network can be clearly identified and the information required for baseline emission calculation for the electric power grid and the heat network is publicly available;

(b) Natural gas is used as main fuel in the project activity cogeneration plant. Small amounts of other start-up or auxiliary fuels can be used, but they shall not comprise more than 1% of total fuel used annually, on an energy basis;

(c) Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity and heat capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity;[2]

(d) Baseline fuel is sufficiently available in the region or country, so as to establish a credible baseline scenario for the entire crediting period;

(e) The customers within the heat network do not co-generate heat and electricity currently.[3]

[1] This limitation is included because the methodology does not provide procedures to estimate the GHG emissions associated with the production of gas from these other sources.

[2] In some situations, there could be price-inelastic supply constraints (e.g. limited resources without possibility of expansion during the crediting period) that could mean that a project activity displaces natural gas that would otherwise be used elsewhere in an economy, thus leading to possible leakage. Hence, it is important for the project participants to document that supply limitations will not result in significant leakage as indicated here.

In addition, the applicability conditions included in the tools referred to above apply.

Finally, this methodology is only applicable if the most plausible baseline scenario, as identified per the section "Selection of the baseline scenario and demonstration of additionality" hereunder, is one of the following:

(a) Construction and operation of new cogeneration plants using fossil fuels other than natural gas (e.g. coal, oil) (P3+H3);

(b) Construction and operation of new power only plants using fossil fuels (e.g. coal, natural gas, oil) for electricity generation, and construction and operation of new heat only boilers using fossil fuels (e.g. coal, natural gas, oil) for heat generation (P5+H5).

# II. BASELINE METHODOLOGY PROCEDURE

## Project boundary

The **spatial extent** of the project boundary encompasses:

(a) The project cogeneration plant;

(b) All power plants connected physically to the electricity system that the project cogeneration plant is connected to in the baseline or project scenario; and

(c) All heat generation facilities, connected physically to the heat network that the project is connected to in the baseline or project scenario.

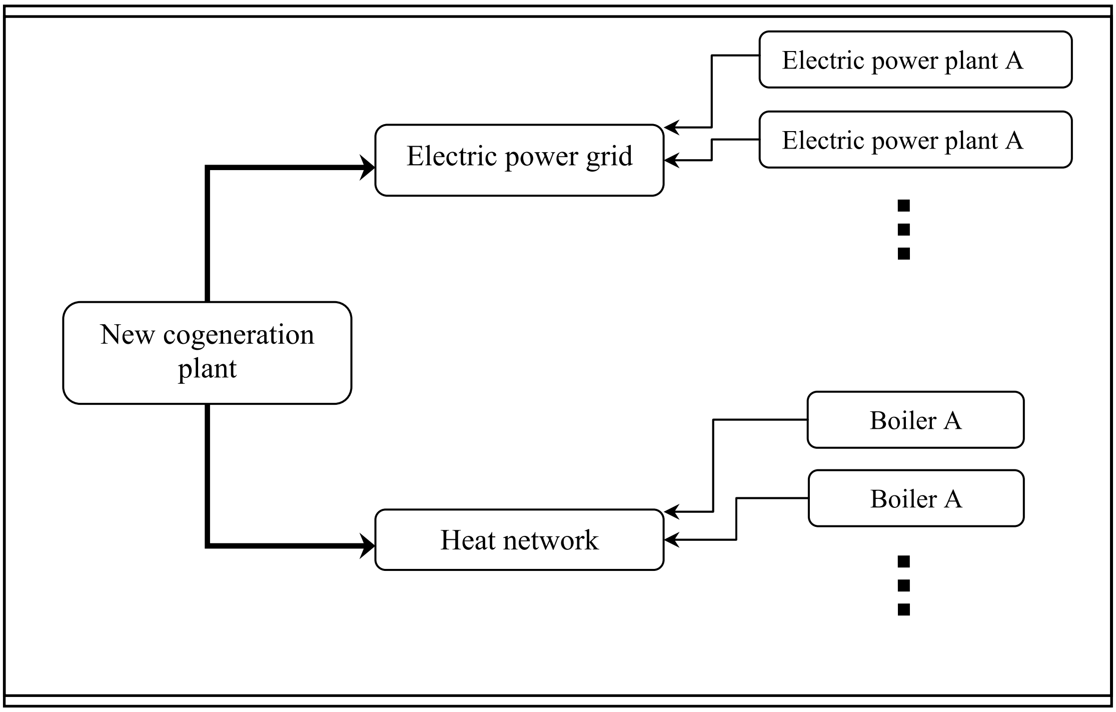


**Figure 1: Project boundary**

[3] This condition is required to simplify the calculation of emission factor of heat network.

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

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

| | Source | Gas | Included? | Justification/Explanation |
|---|---|---|---|---|
| Baseline | Fossil fuel consumption for electricity production | $CO_2$ | Yes | Main emission source |
| | | $CH_4$ | No | Excluded for simplification. This is conservative |
| | | $N_2O$ | No | Excluded for simplification. This is conservative |
| | Fossil fuel consumption for heat production | $CO_2$ | Yes | Main emission source |
| | | $CH_4$ | No | Excluded for simplification. This is conservative |
| | | $N_2O$ | No | Excluded for simplification. This is conservative |
| Project activity | Fossil fuel consumption for generation of heat and electricity in the project plant | $CO_2$ | Yes | Main emission source |
| | | $CH_4$ | No | Excluded for simplification |
| | | $N_2O$ | No | Excluded for simplification |

**Selection of the baseline scenario and demonstration of additionality**

The selection of the baseline scenario and the demonstration of additionality shall be conducted using the latest version of the "Combined tool to identify the baseline scenario and demonstrate additionality". The following additional guidance should be used when applying the tool.

When applying "Sub-step 1a" of the tool, alternative scenarios should include all realistic and credible alternatives to the project activity that are consistent with current laws and regulations of the host country and that provide output or service (i.e. heat and/ or electricity supply) with comparable quality as the proposed CDM project activity. For the purposed project activity, the alternative scenarios should be determined separately for:

(a) Electricity generation;

(b) Heat generation.

For electricity generation, the realistic and credible alternative(s) may include, inter alia:

P1 The project activity not implemented as a CDM project;

P2 Construction and operation of new natural gas fired cogeneration plants for electricity generation but using different technology;

P3 Construction and operation of new cogeneration plants using fossil fuels other than natural gas (e.g. coal, oil);

P4 Construction and operation of new cogeneration plants using renewable energy;

P5 Construction and operation of new power only plants using fossil fuels (e.g. coal, natural gas, oil);

P6 Construction and operation of new power only plants using renewable energy;

P7 Electricity generated by the operation of grid-connected power plants;

P8 Import of electricity from connected grids, including the possibility of new interconnections.

The baseline scenario of electricity generation can be a combination of the above scenarios.

For the generation of heat, the realistic and credible alternative(s) may include, inter alia:

H1 The project activity not implemented as a CDM project;

H2 Construction and operation of new natural gas fired cogeneration plants using different technology;

H3 Construction and operation of new cogeneration plants using fossil fuels other than natural gas (e.g. coal, oil);

H4 Construction and operation of new cogeneration plants using renewable energy;

H5 Construction and operation of new heat only boilers using fossil fuels (e.g. coal, natural gas, oil);

H6 Construction and operation of heat generation facilities using electricity (such as electric furnaces, electric boilers;

H7 Construction and operation of new heat generation facilities using renewable energy (such as biomass, terrestrial heat, solar thermal collectors etc.);

H8 Construction and operation of new heat generation facilities using non-renewable biomass;

H9 Heat generation by existing heat generation facilities within the heat network;

H10 Import of heat from connected heat network, including the possibility of new inter-connections.

The baseline scenario of heat generation can be a combination of the above scenarios.

When developing alternative scenarios for the project activity, based on baseline scenarios identified separately for electricity and heat, credible and realistic combination of baseline alternatives shall be identified.

While applying Step 3 of the tool, following guidance should be used.

The level of profitability for different alternative scenarios (such as IRR or NPV) should be used as criteria of investment comparison analysis. The baseline scenario with the best financial indicators shall be selected as the most feasible baseline scenario.

The sensitivity analysis should also consider variations between heat to electricity ratios, as the level of profitability of two sources are different. For example, if the project is additional for the variation of heat-to-electricity ratio by +/- 10%, then the heat-to-electricity ratio should be within this range in the project period. This shall be done by including a parameter ($\theta_{PJ,y}$).

The heat-to-electricity ratio of the cogeneration plant in year *y* ($\theta_{PJ,y}$) can be determined as follows:

$$\theta_{PJ,y} = \frac{HG_{PJ,y}}{3.6 \times EG_{PJ,y}} \tag{1}$$

Where:

| | | |
|---|---|---|
| $\theta_{PJ,y}$ | = | Heat-to-electricity ratio of the cogeneration plant in year *y* |
| $HG_{PJ,y}$ | = | Quantity of heat supplied by the project activity in year *y* (GJ) |

| | | |
|---|---|---|
| $EG_{PJ,y}$ | = | Quantity of electricity generated in the project cogeneration plant that is fed into the electric power grid in year *y* (MWh) |
| *3.6* | = | Conversion factor, expressed as GJ/MWh |

**Baseline emissions**

Baseline emissions are calculated as:

$$BE_y = \min(BE_{COGEN,y}, BE_{SEPGEN,y}) \tag{2}$$

Where:

| | | |
|---|---|---|
| $BE_y$ | = | Baseline emissions in year *y* ($tCO_2e$) |
| $BE_{COGEN,y}$ | = | Baseline emissions due to cogeneration of electricity and heat in year *y* ($tCO_2e$) |
| $BE_{SEPGEN,y}$ | = | Baseline emissions due to generation of electricity and heat separately in year *y* ($tCO_2e$) |

*Determination of baseline emissions produced by cogeneration of electricity and heat ($BE_{COGEN,y}$)*

Baseline emissions due to cogeneration of electricity and heat shall be calculated as follows:

$$BE_{COGEN,y} = \left[ \frac{HG_{PJ,y} + EG_{PJ,y} \times 3.6}{\eta_{BL,COGEN}} \right] \times EF_{BL,COGEN} \tag{3}$$

Where:

| | | |
|---|---|---|
| $BE_{COGEN,y}$ | = | Baseline emissions due to cogeneration of electricity and heat in year *y* ($tCO_2e$) |
| $HG_{PJ,y}$ | = | Quantity of heat supplied by the project activity in year *y* (GJ) |
| $EG_{PJ,y}$ | = | Quantity of electricity generated in the project cogeneration plant that is fed into the electric power grid in year *y* (MWh) |
| *3.6* | = | Conversion factor, expressed as GJ/MWh |
| $EF_{BL,COGEN}$ | = | $CO_2$ emission factor per unit of energy of the fuel that would have been used in the baseline cogeneration plant ($tCO_2/GJ$) |
| $\eta_{BL,COGEN}$ | = | Overall efficiency of baseline fossil fuel cogeneration plant that would have been used in the absence of the project activity (Fraction) |

*Determination of $CO_2$ emission factor per unit of energy of the fuel that would have been used in the baseline cogeneration plant ($EF_{BL,COGEN}$)*

$EF_{BL,COGEN}$ shall be determined as follows:

**Case 1 - Baseline scenario as "separate generation" (P5+H5)**

Where project participants identify separate generation as the most plausible baseline scenario as per the section "selection of the baseline scenario and demonstration of additionality" above, the $CO_2$ emission factor per unit of energy of the fuel that would have been used in the baseline cogeneration plant ($EF_{BL,COGEN}$) shall be determined for the fuel identified as the baseline fuel in the baseline power plant (below).

**Case 2 - Baseline scenario as "cogeneration" (P3+H3)**

Where project participants identify cogeneration as the most plausible baseline scenario as per the section "selection of the baseline scenario and demonstration of additionality" above, the $CO_2$

emission factor per unit of energy of the fuel that would have been used in the baseline cogeneration plant ($EF_{BL,COGEN}$) shall be determined for the fuel identified as the baseline fuel in the baseline cogeneration plant.

*Determination of the overall efficiency of baseline fossil fuel cogeneration plant that would have been used in the absence of the project activity ($\eta_{BL,COGEN}$)*

The overall efficiency of the baseline cogeneration plant ($\eta_{BL,COGEN}$) shall be determined as follows:

Step 1:

(a) A default steam turbine efficiency of 100%;

(b) A default steam generator efficiency determined using the "Tool to determine the baseline efficiency of thermal or electric energy generation systems".

Step 2:

(a) The overall efficiency of the baseline cogeneration plant ($\eta_{BL,COGEN}$) is then calculated as the product of the efficiency value for the steam turbine(s) and the efficiency value of the steam generator(s), assuming both efficiencies are in the form of a percentage of output per input.

The values determined for $\eta_{BL,COGEN}$ should be documented in the CDM-PDD and shall in general remain fixed throughout the crediting period.

*Determination of baseline emissions produced by generation of electricity and heat separately ($BE_{SEPGEN,y}$)*

Baseline emissions due to generation of electricity and heat separately shall be calculated as follows:

$$BE_{SEPGEN,y} = BE_{EG,y} + BE_{HG,y} \tag{4}$$

Where:

| | | |
|---|---|---|
| $BE_{SEPGEN,y}$ | = | Baseline emissions produced by generation of electricity and heat separately in year $y$ ($tCO_2e$) |
| $BE_{EG,y}$ | = | Baseline emissions for electricity generation in year $y$ ($tCO_2e$) |
| $BE_{HG,y}$ | = | Baseline emissions for heat generation in year $y$ ($tCO_2e$) |

*Determination of baseline emissions for electricity generation ($BE_{EG,y}$)*

Baseline emissions for electricity generation ($BE_{EG,y}$) are calculated by multiplying the electricity generated in the project plant with a baseline emission factor for electricity generation in year $y$ ($EF_{BL,EG,CO2,y}$), as follows:

$$BE_{EG,y} = EG_{PJ,y} \times EF_{BL,EG,CO2,y} \tag{5}$$

Where:

| | | |
|---|---|---|
| $BE_{EG,y}$ | = | Baseline emissions for electricity generation in year $y$ ($tCO_2e$) |
| $EG_{PJ,y}$ | = | Quantity of electricity generated in the project cogeneration plant that is fed into the electric power grid in year $y$ (MWh) |
| $EF_{BL,EG,CO2,y}$ | = | Baseline emission factor for electricity generation in year $y$ ($tCO_2$/MWh) |

Baseline emission factor for electricity generation ($EF_{BL,EG,CO2,y}$) shall be the lowest among the following three emission factors:

EF 1 The build margin, calculated according to the latest version of the “Tool to calculate the emission factor for an electricity system” approved by the Board ($EF_{BL,EG,CO2,y} = EF_{grid,BM,y}$);

EF 2 The combined margin, calculated according to the latest version of the “Tool to calculate the emission factor for an electricity system” approved by the Board, using a 50/50 OM/BM weight ($EF_{BL,EG,CO2,y} = EF_{grid,CM,y}$);

EF 3 The emission factor of the baseline fossil fuel power plant calculated as:

$$EF_{BL,EG,CO2,y} = \frac{EF_{BL,EG}}{\eta_{BL,EG}} \times 3.6 \quad \textbf{(6)}$$

Where:

| | | |
|---|---|---|
| $EF_{BL,EG,CO2,y}$ | = | Baseline emission factor for electricity generation ($tCO_2/MWh$) |
| $EF_{BL,EG}$ | = | $CO_2$ emission factor of the fuel used in the baseline power plant ($tCO_2/GJ$) |
| $\eta_{BL,EG}$ | = | The energy efficiency of the baseline fossil fuel fired power plant (Fraction) |
| *3.6* | = | Conversion factor, expressed as GJ/MWh |

In case of EF1 (BM) and EF2 (CM), $EF_{BL,EG,CO2,y}$ shall be monitored ex post as described in the “Tool to calculate the emission factor for an electricity system”.

In case of EF 3, $EF_{BL,EG,CO2,y}$ shall be determined once at the validation stage based on an ex ante assessment.

*Determination of $CO_2$ emission factor of the fuel used in the baseline power plant ($EF_{BL,EG}$)*

$EF_{BL,EG}$ shall be determined as follows:

**Case I - Baseline scenario as “separate generation” (P5+H5)**

Where project participants identify separate generation as the most plausible baseline scenario as per the section “selection of the baseline scenario and demonstration of additionality” above, the $CO_2$ emission factor of the fuel used in the baseline power plant ($EF_{BL,EG}$) shall be determined for the fuel identified as the baseline fuel in the baseline power plant.

**Case II - Baseline scenario as “cogeneration” (P3+H3)**

Where project participants identify cogeneration as the most plausible baseline scenario as per the section “selection of the baseline scenario and demonstration of additionality” above, the $CO_2$ emission factor of the fuel used in the baseline power plant ($EF_{BL,EG}$) shall be determined for the fuel identified as the baseline fuel in the baseline cogeneration plant.

*Determination of the energy efficiency of the baseline fossil fuel fired power plant ($\eta_{BL,EG}$)*

The efficiency of this baseline fossil fuel power plant ($\eta_{BL,EG}$) shall be taken as the most efficient technology using the same fossil fuel type as per the Annex 1 of the “Tool to calculate the emission factor for an electricity system”.

The values determined for $\eta_{BL,EG}$ should be documented in the CDM-PDD and shall in general remain fixed throughout the crediting period.

*Determination of baseline emissions for heat generation ($BE_{HG,y}$)*

Baseline emissions for heat generation $BE_{HG,y}$ are calculated by multiplying the heat generated in the project plant with a baseline $CO_2$ emission factor for heat generation, as follows:

$$BE_{HG,y} = HG_{PJ,y} \times EF_{BL,HG,y} \quad (7)$$

Where:

| | | |
|---|---|---|
| $BE_{HG,y}$ | = | Baseline emissions for heat generation in year *y* ($tCO_2e$) |
| $HG_{PJ,y}$ | = | Quantity of heat supplied by the project activity in year *y* (GJ) |
| $EF_{BL,HG,y}$ | = | Baseline emission factor for heat generation in year *y* ($tCO_2$/GJ) |

*Determination of baseline emission factor for heat generation ($EF_{BL,HG,y}$)*

Baseline emission factor for heat generation shall be determined following one of the options below:

Option 1: The emission factor of the heat network in year y (i.e. $EF_{BL,HG,y} = EF_{BL,HG,network,CO2,y}$).

Option 2: Conservative default emission factor of zero, i.e. $EF_{BL,HG,y} = 0$.

*Determination of emission factor of the heat network ($EF_{BL,HG,network,CO2,y}$)*

The emission factor of newly created heat network shall be considered as zero for simplification.[4] The emission factor of the existing heat network shall be determined as follows:

$$EF_{BL,HG,network,CO2,y} = \min(EF_{BL,HG,operating,CO2,y}, EF_{BL,HG,reference,CO2,y}) \quad (8)$$

Where:

| | | |
|---|---|---|
| $EF_{BL,HG,network,CO2,y}$ | = | The emission factor of the heat network in year *y* ($tCO_2$/GJ) |
| $EF_{BL,HG,operating,CO2,y}$ | = | The emission factor of operating heat generation facilities within the heat network in year *y* ($tCO_2$/GJ) |
| $EF_{BL,HG,reference,CO2,y}$ | = | The emission factor of reference heat generation facility based on recently built heat generation facilities year *y* ($tCO_2$/GJ) |

The emission factor of operating heat generation facilities or reference heat generation facility can be calculated using either of the two following data vintages:

(a) Ex ante option: if the ex ante option is chosen, the emission factor is determined once at the validation stage, thus no monitoring and recalculation of the emissions factor during the crediting period is required. A 3-year historical generation-weighted average shall be used based on the most recent data available at the time of submission of the CDM-PDD to the DOE for validation;

[4] If project participants wish to claim emission reductions for newly created heat network, they shall submit request for revision of this methodology, with procedures to calculate emission factor from newly created heat network.

(b) Ex post option: If the ex post option is chosen, the emission factor is determined for the year in which the project activity supplies heat to the heat network, requiring the emissions factor to be updated annually during monitoring. If the data required to calculate the emission factor for year *y* is usually available after six months from the end of year *y*, alternatively the emission factor of the previous year (y-1) may be used. If the data is usually available 18 months from the end of year *y*, the emission factor of the year proceeding the previous year (y-2) may be used. The same data vintage (y, y-1 or y-2) should be used throughout all crediting periods.

*Determination of emission factor of operating heat generation facilities within in the heat network ($EF_{BL,HG,operating,CO2,y}$)*

The emission factor of operating heat generation facilities shall be calculated as follows:

$$EF_{BL,HG,operating,CO2,y} = \frac{\sum_{m}\left(HG_{m,y} \times EF_{BL,HG,m}\right)}{\sum_{m} HG_{m,y}} \times \left(1 - \delta_{BL,network}\right) \quad \textbf{(9)}$$

Where:

| | | |
|---|---|---|
| $EF_{BL,HG,operating,CO2,y}$ | = | The emission factor of operating heat generation facilities within the heat network in year *y* ($tCO_2/GJ$) |
| $HG_{m,y}$ | = | Heat supplied by the heat generation facility *m* within the heat network in year *y* (GJ) |
| $EF_{BL,HG,m}$ | = | Baseline emission factor for heat generation of the operating heat generation facility *m* ($tCO_2/GJ$) |
| $m$ | = | All operating heat generation facilities within the heat network |
| $\delta_{BL,network}$ | = | Average heat loss of the heat network (Fraction) |

*Determination of emission factor of reference heat generation facility based on recently built heat generation facilities ($EF_{BL,HG,reference,CO2,y}$)*

The emission factor of reference heat generation facility is calculated as follows:

The sample group of heat generation facilities *n* used to calculate the emission factor of reference heat generation facility should be determined as per the following procedure, consistent with the data vintage selected above:

(a) Identify the set of five heat generation facilities, excluding facilities registered as CDM project activities, that started to supply heat to the heat network most recently ($SET_{5\text{-facilities}}$) and determine their annual heat generation ($AHG_{SET5\text{-facilities}}$, in GJ);

(b) Determine the annual heat generation of the heat network, excluding facilities registered as CDM project activities ($AHG_{total}$, in GJ). Identify the set of heat generation facilities, excluding facilities registered as CDM project activities, that started to supply heat to the network most recently and that comprise 20% of $AHG_{total}$ (if 20% falls on part of the generation of a unit, the generation of that facility is fully included in the calculation) ($SET_{\geqslant 20\%}$) and determine their annual heat generation ($AHG_{SET\geqslant 20\%}$, in GJ);

(c) From $SET_{5\text{-facilities}}$ and $SET_{\geq 20\%}$ select the set of heat generation facilities that comprises the larger annual heat generation ($SET_{sample}$); Identify the date when the heat generation facilities in $SET_{sample}$ started to supply heat to the network. If none of the heat generation facilities in $SET_{sample}$ started to supply heat to the heat network more than 10 years ago, then use $SET_{sample}$ to calculate the emission factor of reference heat generation facility. In this case ignore steps (d), (e) and (f).

Otherwise:

(d) Exclude from $SET_{sample}$ the heat generation facilities which started to supply heat to the network more than10 years ago. Include in that set the heat generation facilities registered as CDM project activities, starting with facilities that started to supply heat to the network most recently, until the heat generation of the new set comprises 20% of the annual heat generation of the heat network (if 20% falls on part of the generation of a unit, the generation of that facility is fully included in the calculation) to the extent is possible. Determine for the resulting set ($SET_{sample\text{-}CDM}$) the annual heat generation ($AHG_{SET\text{-}sample\text{-}CDM}$, in GJ);

If the annual heat generation of that set comprises at least 20% of the annual heat generation of the heat network (i.e. $AHG_{SET\text{-}sample\text{-}CDM} \geq 0.2 \times AHG_{total}$), then use the sample group $SET_{sample\text{-}CDM}$ to calculate the emission factor of reference heat generation facility. Ignore steps (e) and (f).

Otherwise:

(e) Include in the sample group $SET_{sample\text{-}CDM}$ the facilities that started to supply heat to the heat network more than 10 years ago until the heat generation of the new set comprises 20% of the annual heat generation of the heat network (if 20% falls on part of the generation of a unit, the generation of that facility is fully included in the calculation);

(f) The sample group of facilities $n$ used to calculate the emission factor of reference heat generation facility is the resulting set ($SET_{sample\text{-}CDM}$>10yrs).

The emission factor of reference heat generation facility is the emission factor ($tCO_2/GJ$) of all heat generation facilities $n$ during the most recent year $y$, calculated as follows:

$$EF_{BL,HG,reference,CO2,y} = \frac{\sum_n \left(HG_{n,y} \times EF_{BL,HG,n}\right)}{\sum_n HG_{n,y}} \times \left(1 - \delta_{BL,network}\right) \quad \textbf{(10)}$$

Where:

| | | |
|---|---|---|
| $EF_{BL,HG,reference,CO2,y}$ | = | The emission factor of the reference heat generation facility in year $y$ ($tCO_2/GJ$) |
| $HG_{n,y}$ | = | Heat supplied by the heat generation facility $n$ within the heat network in year $y$ (GJ) |
| $EF_{BL,HG,n}$ | = | Baseline emission factor for heat generation of heat generation facility $n$ ($tCO_2/GJ$) |
| $n$ | = | All sample group of heat generation facilities selected through above procedures |
| $\delta_{BL,network}$ | = | Average heat loss of the heat network (Fraction) |

For heat only boilers, the emission factor can be calculated as follows:

$$EF_{BL,HG,m} = \frac{EF_{BL,HG,m,CO2}}{\eta_{BL,HG,m}} \tag{11}$$

$$EF_{BL,HG,n} = \frac{EF_{BL,HG,n,CO2}}{\eta_{BL,HG,n}} \tag{12}$$

Where:

| | | |
|---|---|---|
| $EF_{BL,HG,m}$ | = | Baseline emission factor for heat generation of the operating heat generation facility *m* ($tCO_2/GJ$) |
| $EF_{BL,HG,n}$ | = | Baseline emission factor for heat generation of heat generation facility *n* ($tCO_2/GJ$) |
| $EF_{BL,HG,m,CO2}$ | = | $CO_2$ emission factor of fuel used in the operating heat generation facility *m* ($tCO_2/GJ$) |
| $EF_{BL,HG,n,CO2}$ | = | $CO_2$ emission factor of fuel used in the heat generation facility *n* ($tCO_2/GJ$) |
| $\eta_{BL,HG,m}$ | = | Energy efficiency for heat generation of the operating heat generation facility *m* (Fraction) |
| $\eta_{BL,HG,n}$ | = | Energy efficiency for heat generation of the heat generation facility *n* (Fraction) |

For fossil fuel fired heat only boilers, the energy efficiency for heat generation of heat generation facility *m* or *n* ($\eta_{BL,HG,m}$ or $\eta_{BL,HG,m}$) is calculated using one of the following approaches:

(a) Conduct a representative number of sample measurements of efficiency for similar boiler types at the project site prior to the implementation of the project activity or at other sites with comparable circumstances using the approach described in the latest approved version of AM0044 “Energy efficiency improvement projects: boiler rehabilitation or replacement in industrial and district heating sectors”;

(b) Use documented manufacturer’s data on the boiler efficiency;

(c) Use the default values from the Table 1 of the “Tool to determine the baseline efficiency of thermal or electric energy generation systems”;

(d) Determine the boiler efficiency based on historical fuel consumption data.

Project participants shall determine whether the existing equipment would be replaced, retrofitted or modified during the project lifetime. Project participants shall determine the point in time when the existing boiler(s) would be replaced in the absence of the project activity as per the “Tool to determine the remaining lifetime of equipment”, and calculate the average remaining lifetime of existing boilers/cogeneration plants using capacity of each boiler/cogeneration plant as weighting.

For heat generation facilities and boilers after the end of its lifetime, the emission factors shall be treated as 0, i.e. $EF_{BL,HG,m} = 0$ and $EF_{BL,HG,n} = 0$.

If relevant data for the calculation of emission factor of the heat network is not available, a conservative value 0 can be used, i.e.: $EF_{BL,HG,network,CO2,y} = 0$.

**Project emissions**

Project emissions result from the combustion of natural gas and small amounts of other start-up or auxiliary fuels in the cogeneration plant. Project emissions ($PE_y$) shall be calculated as the $CO_2$ emissions from fossil fuel(s) combustion associated with the production of heat and electricity in the cogeneration plant, using the latest approved version of the "Tool to calculate project or leakage $CO_2$ emissions from fossil fuel combustion". The parameter $PE_y$ corresponds to $PE_{FC,j,y}$ in the tool, where *j* is the combustion of natural gas and small amounts of other start-up or auxiliary fuels in the cogeneration plant.

**Leakage**

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This leakage includes mainly: (i) fugitive $CH_4$ emissions; (ii) $CO_2$ emissions from the process of $CO_2$ removal from the raw natural gas stream in order to upgrade the natural gas to the required market conditions; and (iii) $CO_2$ emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered:

(a) Fugitive $CH_4$ emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the cogeneration plant and fossil fuels used in the absence of the project activity;

(b) $CO_2$ emissions from the process of $CO_2$ removal from the raw natural gas stream in order to upgrade the natural gas to the required market conditions;

(c) In the case that liquefied natural gas (LNG) is used in the cogeneration plant, $CO_2$ emissions due to fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{CO2,y} + LE_{LNG,CO2,y} \tag{13}$$

Where:

| | | |
|---|---|---|
| $LE_y$ | = | Leakage emissions ($tCO_2e$) |
| $LE_{CH4,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions in year *y* ($tCO_2e$) |
| $LE_{CO2,y}$ | = | Leakage emissions due to the removal of $CO_2$ from the raw natural gas stream in year *y* ($tCO_2e$) |
| $LE_{LNG,CO2,y}$ | = | Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year *y* ($tCO_2e$) |

To the extent that upstream emissions occur in Annex I countries that have ratified the Kyoto Protocol, from 1 January 2008 onwards, these emissions should be excluded, if technically possible, in the leakage calculations.

*Determination of leakage emissions due to upstream fugitive methane emissions ($LE_{CH4,y}$)*

$$LE_{CH4,y} = LE_{PJ,y} - LE_{BL,y} \tag{14}$$

Where:

| | | |
|---|---|---|
| $LE_{CH4,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions in year $y$ ($tCO_2e$) |
| $LE_{PJ,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from natural gas used in the project activity in year $y$ ($tCO_2e$) |
| $LE_{BL,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used in the absence of the project activity in the year $y$ ($tCO_2e$) |

*Determination of leakage emissions due to upstream fugitive $CH_4$ emissions from natural gas used in the project activity ($LE_{PJ,y}$)*

$$LE_{PJ,y} = \left(FC_y \times NCV_{NG,y} \times EF_{NG,upstream,CH4}\right) \times GWP_{CH4} \quad \textbf{(15)}$$

Where:

| | | |
|---|---|---|
| $LE_{PJ,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from natural gas used in the project activity in year $y$ ($tCO_2e$) |
| $FC_y$ | = | Quantity of natural gas combusted in the cogeneration plant in year $y$ ($m^3$) |
| $NCV_{NG,y}$ | = | Average net calorific value of the natural gas combusted in year $y$ ($GJ/m^3$) |
| $EF_{NG,upstream,CH4}$ | = | Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system ($tCH_4/GJ$) |
| $GWP_{CH4}$ | = | Global warming potential of methane valid for the relevant commitment period ($tCO_2/tCH_4$) |

Note that the emission factor for upstream fugitive emissions for natural gas ($EF_{NG,upstream,CH4}$) should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the Table 2 below. Where default values from this table are used, the natural gas emission factors for the location of the project activity should be used.

*Determination of leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used in the absence of the project activity ($LE_{BL,y}$)*

Note that the upstream fugitive $CH_4$ emissions occurring in the absence of the project activity should be calculated consistent with the baseline emission analysed above, as the lowest of the follows:

(a) Baseline leakage emissions for cogeneration of electricity and heat;

(b) Baseline leakage emissions for generation of electricity and heat separately;

$$LE_{BL,y} = min\left(LE_{BL,COGEN,y}, LE_{BL,SEPGEN,y}\right) \quad \textbf{(16)}$$

Where:

| | | |
|---|---|---|
| $LE_{BL,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used in the absence of the project activity in the year $y$ ($tCO_2e$) |
| $LE_{BL,COGEN,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for cogeneration of electricity and heat in the absence of the project activity in year $y$ ($tCO_2e$) |
| $LE_{BL,SEPGEN,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for generation of electricity and heat separately in the absence of the project activity in year $y$ ($tCO_2e$) |

*Determination of leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for cogeneration of electricity and heat in the absence of the project activity ($LE_{BL,COGEN,y}$)*

$$LE_{BL,COGEN,y} = \left( \frac{HG_{PJ,y} + EG_{PJ,y} \times 3.6}{\eta_{BL,COGEN} \times NCV_{BL,FF,COGEN}} \right) \times EF_{BL,FF,COGEN,upstream,CH4} \times GWP_{CH4} \quad \textbf{(17)}$$

Where:

| | | |
|---|---|---|
| $LE_{BL,COGEN,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for cogeneration of electricity and heat in the absence of the project activity in year *y* ($tCO_2e$) |
| $HG_{PJ,y}$ | = | Quantity of heat supplied by the project activity in year *y* (GJ) |
| $EG_{PJ,y}$ | = | Quantity of electricity generated in the project cogeneration plant that is fed into the electric power grid in year *y* (MWh) |
| *3.6* | = | Conversion factor, expressed as GJ/MWh |
| $\eta_{BL,COGEN}$ | = | Overall efficiency of baseline fossil fuel cogeneration plant that would have been used in the absence of the project activity (Fraction) |
| $NCV_{BL,FF,COGEN}$ | = | Net calorific value of fuel that would have been used in the baseline cogeneration plant (GJ/mass or volume unit) |
| $EF_{BL,FF,COGEN,upstream,CH4}$ | = | Emission factor for upstream fugitive $CH_4$ emissions from production of the fuel that would have been used in the baseline cogeneration plant ($tCH_4$/mass or volume unit) |
| $GWP_{CH4}$ | = | Global warming potential of methane valid for the relevant commitment period ($tCO_2/tCH_4$) |

*Determination of leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for generation of electricity and heat separately in the absence of the project activity ($LE_{BL,SEPGEN,y}$)*

$$LE_{BL,SEPGEN,y} = LE_{BL,EG,y} + LE_{BL,HG,y} \quad \textbf{(18)}$$

Where:

| | | |
|---|---|---|
| $LE_{BL,SEPGEN,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for generation of electricity and heat separately in the absence of the project activity in year *y* ($tCO_2e$) |
| $LE_{BL,EG,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for generation of electricity in year *y* ($tCO_2e$) |
| $LE_{BL,HG,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for generation of heat in year *y* ($tCO_2e$) |

*Determination of leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for generation of electricity ($LE_{BL,EG,y}$)*

$$LE_{BL,EG,y} = EG_{PJ,y} \times EF_{BL,EG,upstream,CH4,y} \times GWP_{CH4} \quad \textbf{(19)}$$

Where:

| | | |
|---|---|---|
| $LE_{BL,EG,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for generation of electricity in year *y* ($tCO_2e$) |
| $EG_{PJ,y}$ | = | Quantity of electricity generated in the project cogeneration plant that is fed into the electric power grid in year *y* (MWh) |

| | | |
|---|---|---|
| $EF_{BL,EG,upstream,CH4,y}$ | = | Emission factor for upstream fugitive $CH_4$ emissions for electricity generation in the absence of the project activity in year *y* ($tCH_4/MWh$) |
| $GWP_{CH4}$ | = | Global warming potential of methane valid for the relevant commitment period ($tCO_2/tCH_4$) |

The emission factor for upstream fugitive $CH_4$ emissions for electricity generation in the absence of the project activity in year *y* ($EF_{BL,EG,upstream,CH4,y}$) should be calculated consistent with the baseline emission factor ($EF_{BL,EG,CO2,y}$) used in estimation of baseline emissions, as follows:

Option 1: Build margin:

$$EF_{BL,EG,upstream,CH4,y} = \frac{\sum_j \sum_k FF_{j,k,y} \times NCV_{j,k,y} \times EF_{k,upstream,CH4}}{\sum_j EG_{j,y}} \quad \textbf{(20)}$$

Option 2: Combined margin:

$$EF_{BL,EG,upstream,CH4,y} = 0.5 \times \frac{\sum_j \sum_k FF_{j,k,y} \times NCV_{j,k,y} \times EF_{k,upstream,CH4}}{\sum_j EG_{j,y}} + 0.5 \times \frac{\sum_i \sum_k FF_{i,k,y} \times NCV_{i,k,y} \times EF_{k,upstream,CH4}}{\sum_i EG_{i,y}} \quad \textbf{(21)}$$

Option 3: Baseline technology:

$$EF_{BL,EG,upstream,CH4,y} = \frac{EF_{k,upstream,CH4}}{\eta_{BL,EG}} \times 3.6 \quad \textbf{(22)}$$

Where:

| | | |
|---|---|---|
| $EF_{BL,EG,upstream,CH4,y}$ | = | Emission factor for upstream fugitive $CH_4$ emissions occurring in the absence of the project activity power plant in year *y* ($tCH_4/MWh$) |
| *j* | = | Plants included in the build margin |
| $FF_{j,k,y}$ | = | Quantity of fuel type *k* (a coal or oil type) combusted in power plant *j* included in the build margin in year *y* (mass or volume units) |
| $NCV_{j,k,y}$ | = | Average net calorific value of fuel type *k* (a coal or oil type) combusted in power plant *j* included in the build margin in year *y* (GJ/mass or volume units) |
| $EF_{k,upstream,CH4}$ | = | Emission factor for upstream fugitive $CH_4$ emissions from production of the fuel type *k* (a coal or oil type) (tCH4/GJ) |
| $EG_{j,y}$ | = | Electricity generation in the plant *j* included in the build margin in year *y* (MWh) |
| *i* | = | Plants included in the operating margin |
| $FF_{i,k,y}$ | = | Quantity of fuel type *k* (a coal or oil type) combusted in power plant *i* included in the operating margin in year *y* (mass or volume units) |
| $NCV_{i,k,y}$ | = | Average net calorific value of fuel type *k* (a coal or oil type) combusted in power plant *i* included in the operating margin in year *y* (GJ/mass or volume units) |
| $EG_{i,y}$ | = | Electricity generation in the plant *i* included in the operating margin in year *y* (MWh) |
| $\eta_{BL,EG}$ | = | The energy efficiency of the baseline technology (Fraction) |

If $EF_{BL,EG,upstream,CH4,y}$ is determined based on the build margin or the combined margin, the calculation should be consistent with the calculation of $CO_2$ emissions in the build margin and the combined margin, i.e. the same cohort of plants and data on fuel combustion and electricity generation should be used, and the values for *FF* and *EG* should be those already determined through the application of "Tool to calculate the emission factor for an electricity system".

*Determination of the emission factor for upstream fugitive $CH_4$ emissions from production of the fuel type k ($EF_{k,upstream,CH4}$)*

Where reliable and accurate national data on fugitive $CH_4$ emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of $CH_4$ emissions by the quantity of fuel produced or supplied respectively.[5] Where such data is not available, project participants should use the default values provided in Table 2 below.

*Determination of leakage emissions due to upstream fugitive CH4 emissions from fossil fuels used for generation of heat ($LE_{BL,HG,y}$)*

$$LE_{BL,HG,y} = HG_{PJ,y} \times EF_{BL,HG,upstream,CH4,y} \times GWP_{CH4} \tag{23}$$

Where:

| | | |
|---|---|---|
| $LE_{BL,HG,y}$ | = | Leakage emissions due to upstream fugitive $CH_4$ emissions from fossil fuels used for generation of heat in year *y* ($tCO_2e$) |
| $HG_{PJ,y}$ | = | Quantity of heat supplied by the project activity in year *y* (GJ) |
| $EF_{BL,HG,upstream,CH4,y}$ | = | Emission factor for upstream fugitive $CH_4$ emissions for heat generation in the absence of the project activity in year *y* ($tCH_4$/GJ) |

The emission factor for upstream fugitive $CH_4$ emissions for heat generation in the absence of the project activity in year *y* ($EF_{BL,HG,upstream,CH4,y}$) shall be calculated consistent with the baseline emission factor ($EF_{BL,HG,y}$) used in estimation of baseline emissions, as follows:

$$EF_{BL,HG,upstream,CH4,y} = min\left[\frac{\sum_m \left(HG_{m,y} \times \frac{EF_{m,upstream,CH4}}{\eta_{BL,HG,m} \times NCV_{BL,HG,m}}\right)}{\sum_m HG_{m,y}}, \frac{\sum_n \left(HG_{n,y} \times \frac{EF_{n,upstream,CH4}}{\eta_{BL,HG,n} \times NCV_{BL,HG,n}}\right)}{\sum_n HG_{n,y}}\right] \tag{24}$$

Where:

| | | |
|---|---|---|
| $EF_{BL,HG,upstream,CH4,y}$ | = | Emission factor for upstream fugitive $CH_4$ emissions for heat generation in the absence of the project activity in year *y* ($tCH_4$/GJ) |
| $EF_{m,upstream,CH4}$ | = | Emission factor for upstream fugitive $CH_4$ emissions from production of the fuel used in the heat generation facility *m* in t $CH_4$/ mass unit fuel produced |
| $EF_{n,upstream,CH4}$ | = | Emission factor for upstream fugitive $CH_4$ emissions from production of the fuel used in the heat generation facility *n* in t $CH_4$/mass unit fuel produced |
| $HG_{m,y}$ | = | Heat supplied by the heat generation facility *m* within the heat network in year *y* (GJ) |

[5] GHG inventory data reported to the UNFCCC as part of national communications can be used where country-specific approaches (and not IPCC Tier 1 default values) have been used to estimate emissions.

| | | |
|---|---|---|
| $HG_{n,y}$ | = | Heat supplied by the heat generation facility *n* within the heat network in year *y* (GJ) |
| $\eta_{BL,HG,m}$ | = | Energy efficiency of heat generation facility *m* within the heat network |
| $\eta_{BL,HG,n}$ | = | Energy efficiency of heat generation facility *n* within the heat network |
| $NCV_{BL,HG,m}$ | = | Net calorific value of heat generation facility *m* within the heat network (GJ/mass unit) |
| $NCV_{BL,HG,n}$ | = | Net calorific value of heat generation facility *n* within the heat network (GJ/mass unit) |

*Determination of the emission factor for upstream fugitive $CH_4$ emissions from production of the fuel used in the heat generation facility m or n ($EF_{m,upstream,CH4}$ or $EF_{n,upstream,CH4}$)*

Where reliable and accurate national data on fugitive $CH_4$ emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of $CH_4$ emissions by the quantity of fuel produced or supplied respectively.[6] Where such data is not available, project participants should use the default values provided in Table 2 below.

[6] GHG inventory data reported to the UNFCCC as part of national communications can be used where country-specific approaches (and not IPCC Tier 1 default values) have been used to estimate emissions.

**Table 2: Default emission factors for upstream fugitive methane emissions**

| Activity | Unit | Default emission factor | Reference for the underlying emission factor range in Volume 3 of the *1996 Revised IPCC Guidelines* |
|---|---|---|---|
| **Coal** | | | |
| Underground mining | t CH4 / kt coal | 13.4 | Equations 1 and 4, p. 1.105 and 1.110 |
| Surface mining | t CH4 / kt coal | 0.8 | Equations 2 and 4, p.1.108 and 1.110 |
| **Oil** | | | |
| Production | t CH4 / PJ | 2.5 | Tables 1-60 to 1-64, p. 1.129 - 1.131 |
| Transport, refining and storage | t CH4 / PJ | 1.6 | Tables 1-60 to 1-64, p. 1.129 - 1.131 |
| Total | t CH4 / PJ | 4.1 | |
| **Natural gas** | | | |
| ***USA and Canada*** | | | |
| Production | t CH4 / PJ | 72 | Table 1-60, p. 1.129 |
| Processing, transport and distribution | t CH4 / PJ | 88 | Table 1-60, p. 1.129 |
| Total | t CH4 / PJ | 160 | |
| ***Eastern Europe and former USSR*** | | | |
| Production | t CH4 / PJ | 393 | Table 1-61, p. 1.129 |
| Processing, transport and distribution | t CH4 / PJ | 528 | Table 1-61, p. 1.129 |
| Total | t CH4 / PJ | 921 | |
| ***Western Europe*** | | | |
| Production | t CH4 / PJ | 21 | Table 1-62, p. 1.130 |
| Processing, transport and distribution | t CH4 / PJ | 85 | Table 1-62, p. 1.130 |
| Total | t CH4 / PJ | 105 | |
| ***Other oil exporting countries / Rest of world*** | | | |
| Production | t CH4 / PJ | 68 | Table 1-63 and 1-64, p. 1.130 and 1.131 |
| Processing, transport and distribution | t CH4 / PJ | 228 | Table 1-63 and 1-64, p. 1.130 and 1.131 |
| Total | t CH4 / PJ | 296 | |

Note: The emission factors in this table have been derived from IPCC default Tier 1 emission factors provided in Volume 3 of the 1996 Revised IPCC Guidelines, by calculating the average of the provided default emission factor range.

*Determination of leakage emissions due to the removal of $CO_2$ from the raw natural gas stream in year y ($LE_{CO2,y}$)*

In processing natural gas, $CO_2$ contained in the raw gas is removed and usually vented to the atmosphere. The $CO_2$ is removed to upgrade the gas to specifications required for commercial application. Emissions from venting of the $CO_2$ only need to be estimated and included in the leakage emission if the average $CO_2$ content of the raw gas, which is processed in the gas processing plants supplying the applicable gas transmission and distribution system, is higher than 5% on a volume basis. In this case, the leakage emissions $LE_{CO2,y}$ are to be estimated as follows:

$$LE_{CO2,y} = FC_y \times \frac{r_{CO2}}{1 - r_{CO2}} \times \rho_{CO2} \tag{25}$$

Where:

| | | |
|---|---|---|
| $LE_{CO2,y}$ | = | Leakage emissions due to the removal of $CO_2$ from the raw natural gas stream in year $y$ ($tCO_2e$) |
| $FC_y$ | = | Quantity of natural gas combusted in the cogeneration plant in year $y$ ($m^3$) |
| $r_{CO2}$ | = | Average $CO_2$ content in the raw natural gas stream on volume basis (ratio) |
| $\rho_{CO2}$ | = | Density of $CO_2$ under standard conditions ($tCO_2/m^3$) |

*Please note that as a conservative approach, this leakage emission source does not discount the removal of $CO_2$ from the raw natural gas stream in the baseline as it is very difficult to determine the amount of natural gas consumed in the baseline.*

***$CO_2$ emissions from LNG***

Where applicable, $CO_2$ emissions from fuel combustion/electricity and heat consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) should be estimated by multiplying the quantity of natural gas combusted in the project with an appropriate emission factor, as follows:

$$LE_{LNG,CO2,y} = FC_y \times EF_{CO2,upstream,LNG} \qquad \textbf{(26)}$$

Where:

| | | |
|---|---|---|
| $LE_{LNG,CO2,y}$ | = | Leakage emissions due to fossil fuel combustion/heat and electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year $y$ ($tCO_2e$) |
| $FC_y$ | = | Quantity of natural gas combusted in the project plant during the year $y$ ($m^3$) |
| $EF_{CO2,upstream,LNG}$ | = | Emission factor for upstream $CO_2$ emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($tCO_2e/m^3$) |

*Determination of the emission factor for upstream $CO_2$ emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($EF_{CO2,upstream,LNG}$)*

Where reliable and accurate data on upstream $CO_2$ emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 $tCO_2/TJ$ as a rough approximation.[7]

Where total net leakage effects are negative ($LE_y < 0$), project participants should assume $LE_y = 0$.

**Emission reductions**

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \qquad \textbf{(27)}$$

Where:

| | | |
|---|---|---|
| $ER_y$ | = | Emission reductions in year $y$ ($tCO_2e$) |
| $BE_y$ | = | Baseline emissions in year $y$ ($tCO_2e$) |

[7] This value has been derived on data published for North American LNG systems. "Barclay, M. and N. Denton, 2005. Selecting offshore LNG process. <http://www.fwc.com/publications/tech_papers/files/LNJ091105p34-36.pdf> (10th April 2006)".

| | | |
|---|---|---|
| $PE_y$ | = | Project emissions in year *y* ($tCO_2e$) |
| $LE_y$ | = | Leakage emissions in year *y* ($tCO_2e$) |

**Changes required for methodology implementation in 2nd and 3rd crediting periods**

Refer to the latest approved version of the methodological tool "Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period".

~~**Project activity under a programme of activities**~~

~~This methodology is not applicable to programme of activities (PoAs).~~

**Data and parameters not monitored**

| **Data / Parameter:** | $GWP_{CH4}$ |
|---|---|
| Data unit: | $tCO_2/tCH_4$ |
| Description: | Global warming potential of methane valid for the relevant commitment period |
| Source of data: | Default value of 21 for the first commitment period under the Kyoto Protocol |
| Measurement procedures (if any): | - |
| Any comment: | - |

| **Data / Parameter:** | $EF_{BL,COGEN}$, $EF_{BL,EG}$, $EF_{BL,HG,m,CO2}$, $EF_{BL,HG,n,CO2}$ |
|---|---|
| Data unit: | $tCO_2/GJ$ |
| Description: | $CO_2$ emission factor per unit of energy of the fuel that would have been used in the baseline cogeneration plant.<br>$CO_2$ emission factor of the fuel used in the baseline power plant.<br>$CO_2$ emission factor of fuel used in the operating heat generation facility *m*.<br>$CO_2$ emission factor of fuel used in the heat generation facility *n*. |

<table>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>(a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>If (b) is not available<br>These sources can only be used for liquid fuels and should be based on well-documented, reliable sources (such as national energy balances)</td></tr>
<tr><td>(d) IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (c) is not available</td></tr>
</table></td></tr>
<tr><td>Measurement procedures (if any):</td><td>For (a) and (b): Measurements should be undertaken in line with national or international fuel standards</td></tr>
<tr><td>Any comment:</td><td>For (a): if the fuel supplier does provide the NCV value and the $CO_2$ emission factor on the invoice and these two values are based on measurements for this specific fuel, this $CO_2$ factor should be used. If another source for the $CO_2$ emission factor is used or no $CO_2$ emission factor is provided, options (b), (c) or (d) should be used</td></tr>
</table>

| **Data / Parameter:** | $\eta_{BL,HG,m}$, $\eta_{BL,HG,n}$ |
|---|---|
| Data unit: | Fraction |
| Description: | Energy efficiency for heat generation of heat generation facility *m* or *n* |
| Source of data: | Conduct a representative number of sample measurements for similar boiler types at the project site prior to the implementation of the project activity or at other sites with comparable circumstances |
| Measurement procedures (if any): | Sample measurement<br>Use recognized standards for the measurement of the boiler efficiency, such as the “British Standard Methods for Assessing the thermal performance of boilers for steam, hot water and high temperature heat transfer fluids” (BS845). 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 manufacturer’s information transparently in the CDM-PDD |
| Any comment: | Alternatively, project proponents may use manufacturer data or default values as presented in the methodology |

| **Data / Parameter:** | $\delta_{BL,network}$ |
|---|---|
| Data unit: | Fraction |
| Description: | Average heat loss of the heat network |
| Source of data: | Historical value or average value from heat generation statistics, e.g. from local/national regulatory authorities |
| Measurement procedures (if any): | - |
| Any comment: | - |

| **Data / parameter:** | $EG_{j,y,}$ $EG_{i,y}$ |
|---|---|
| Data unit: | MWh |
| Description: | Electricity generation in the plant *j* included in the build margin in year *y*; Electricity generation in the plant *i* included in the operating margin in year *y* |
| Source of data: | Electricity generation statistics, e.g. from central-/regional regulatory authorities |
| Measurement procedures (if any): | - |
| Any comment: | - |

| **Data / Parameter:** | $FF_{j,k,y}$, $FF_{i,k,y}$ |
|---|---|
| Data unit: | GJ |
| Description: | Quantity of fuel type *k* (a coal or oil type) combusted in power plant *j* included in the operating margin in year *y*; Quantity of fuel type *k* (a coal or oil type) combusted in power plant *i* included in the operating margin in year *y* |
| Source of data: | Energy statistics, e.g. from central-/regional regulatory authorities |
| Measurement procedures (if any): | - |
| Any comment: | - |

<table>
<tr><td>Data / Parameter:</td><td>$NCV_{BL,FF,COGEN}$, $NCV_{BL,HG,m}$, $NCV_{BL,HG,n}$</td></tr>
<tr><td>Data unit:</td><td>GJ/mass or volume unit</td></tr>
<tr><td>Description:</td><td>Net calorific value of fossil fuel fired in the cogeneration plant; Net calorific value of heat generation facility m or n</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>(a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>If (b) is not available<br><br>These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances)</td></tr>
<tr><td>(d) IPCC default values at the lower or upper limit whatever is more conservative[8] of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (c) is not available</td></tr>
</table></td></tr>
<tr><td>Measurement procedures (if any):</td><td>For (a) and (b): Measurements should be undertaken in line with national or international fuel standards</td></tr>
<tr><td>Any comment:</td><td>-</td></tr>
</table>

| **Data / Parameter:** | $r_{CO2}$ |
|---|---|
| Data unit: | Ratio |
| Description: | Average $CO_2$ content in the raw natural gas stream on volume basis |
| Source of data: | Official, governmental or public studies; public databases; or written statements from the applicable natural gas processing facility(ies), including the average chemical composition of the raw gas in the reservoirs where the project activity natural gas is extracted from |
| Measurement procedures (if any): | - |
| Any comment: | - |

8 The more conservative value is the value that results in the lower overall emission reductions of the project activity. This may imply using the higher or the lower value, depending on the specific configuration of the project activity.

| **Data / Parameter:** | $\rho_{CO2}$ |
|---|---|
| Data unit: | tonnes/m$^3$ |
| Description: | Density of $CO_2$ under standard conditions |
| Source of data: | A default value of 0.001978 $tCO_2/m_3$ $CO_2$ under standard conditions |
| Measurement procedures (if any): | - |
| Any comment: | - |

## III. MONITORING METHODOLOGY

### Data and parameters monitored

Describe and specify in the CDM-PDD all monitoring procedures, including the type of measurement instrumentation used, the responsibilities for monitoring and QA/QC procedures that will be applied. Where the methodology provides different options (e.g. use of default values or on-site measurements), specify which option will be used. All meters and instruments should be calibrated regularly as per industry practices.

All data collected as part of monitoring should be archived electronically and be kept at least for two years after the end of the last crediting period. One hundred per cent of the data should be monitored if not indicated differently in the comments in the tables below.

In addition, the monitoring provisions in the tools referred to in this methodology apply. Accordingly, $FC_y$ and $NCV_{NG,y}$ should be determined as per the “Tool to calculate project or leakage $CO_2$ emissions from fossil fuel combustion”, and $j$, $i$, $NCV_{j,k,y}$, $NCV_{i,k,y}$, should be determined as per the “Tool to calculate the emission factor for an electricity system”.

| **Data / Parameter:** | $EG_{PJ,y}$ |
|---|---|
| Data unit: | MWh |
| Description: | Quantity of electricity generated in the project cogeneration plant that is fed into the electric power grid in year *y* (MWh) |
| Source of data: | Measured by project participants using electricity meters |
| Measurement procedures (if any): | On-site measurements |
| Monitoring frequency: | Continuously |
| QA/QC procedures: | Cross check measurement results with records for sold electricity |
| Any comment: | - |

| **Data / Parameter:** | $HG_{PJ,y}$ |
|---|---|
| Data unit: | GJ |
| Description: | Quantity of heat supplied by the project activity in year *y* |
| Source of data: | On-site measurements |
| Measurement procedures (if any): | 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 |

| | |
|---|---|
| Monitoring frequency: | Calculated based on continuously monitored data and aggregated as appropriate, to calculate emissions reductions |
| QA/QC procedures: | - |
| Any comment: | - |

| **Data / Parameter:** | $HG_{m,y}$, $HG_{n,y}$ |
|---|---|
| Data unit: | GJ |
| Description: | Heat supplied by the heat generation facility *m* or *n* within the heat network in year *y* |
| Source of data: | Utility or government records or official publications |
| Measurement procedures (if any): | - |
| Monitoring frequency: | Either once for each crediting period using the most recent three historical years for which data is available at the time of submission of the CDM-PDD to the DOE for validation (ex ante option); or annually during the crediting period for the relevant year |
| QA/QC procedures: | - |
| Any comment: | - |

| **Data / Parameter:** | $\theta_{PJ,y}$ |
|---|---|
| Data unit: | Fraction |
| Description: | Heat-to-electricity ratio of the cogeneration plant in year *y* |
| Source of data: | Calculated based on parameters $HG_{PJ,y}$ and $EG_{PJ,y}$ as per equation 1 |
| Measurement procedures (if any): | - |
| Monitoring frequency: | Yearly |
| QA/QC procedures: | - |
| Any comment: | The project participants shall check whether $\theta_{PJ,y}$ is within the range as considered in the sensitivity analysis under "Selection of the baseline scenario and demonstration of additionality" above. Changes to the value of $\theta_{PJ,y}$ beyond the range covered in the sensitivity analysis during the crediting period represent a change to the project design document and the relevant procedures shall apply |

## IV. REFERENCES AND ANY OTHER INFORMATION

Not applicable.

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**History of the document**

| **Version** | **Date** | **Nature of revision(s)** |
|---|---|---|
| 02.0.0 | 21 September 2012 | EB 69, Annex #<br>Revision to:<br>• Remove the restriction for application under a programme of activities (PoA) in line with decision at EB 68 stating that all approved methodologies are eligible for application in a PoA. (EB 68, para 97). |
| 01.0.0 | 20 July 2012 | EB 68, Annex 6<br>Initial adoption. |
| **Decision Class**: Regulatory<br>**Document Type**: Standard<br>**Business Function**: Methodology | | |