Indicative simplified baseline and monitoring methodologies
for selected small-scale CDM project activity categories

TYPE II - ENERGY EFFICIENCY IMPROVEMENT PROJECTS

Project participants shall take into account the general guidance to the methodologies, information on additionality, abbreviations and general guidance on leakage provided at: http://cdm.unfccc.int/methodologies/SSCmethodologies/approved.html.

II.H. Energy efficiency measures through centralization of utility provisions of an industrial facility

Technology/measure

1. This methodology comprises energy efficiency measures implemented through integration of a number of utility provisions (for power, steam/heat/hot air and cooling) of an industrial facility into one single utility. The single utility shall consist of either a Combined Heat and Power (CHP - cogeneration) or a Combined Cooling, Heat and Power (CCHP - tri-generation) installation, replacing one or more:

(a) Existing utility provisions, and/or

(b) Facilities that would have otherwise been built.

~~2. Measures are limited to activities that result in additional steam/heat and/or cooling generation capacity of no more than 5% of the pre-project situation. Consequently, the methodology is not applicable to activities seeking to retrofit existing facility to increase output.~~

2. This methodology is applicable under the following conditions:

(a) Project activity results in total energy saving of no more than 60 GWh (or 180 GWh_{th}) per year;

(b) Project activity does not displace existing CHP or CCHP systems; and

(c) In case of CCHP systems, the project activity shall include the shift from vapour compression chillers using chemical refrigerants to chillers which use refrigerants that have no global warming potential (GWP) and no ozone depleting potential (ODP). This conversion must be voluntary and not mandated by laws or regulations.

3. In case the produced electricity, cooling or steam/heat/hot air are delivered to another facility within the project boundary, a contract between the supplier and consumer of the energy will have to be entered into specifying that only the facility generating the energy can claim emission reductions from the energy displaced.

4. For the purpose of this methodology, natural gas is defined as a gas which consists primarily of methane and which is generated from (i) natural gas fields (non-associated gas), (ii) associated gas found in oil fields. It may be blended up to 1% on a volume basis with gas from

other sources, such as, *inter alia*, biogas generated in biodigesters, gas from coal mines, gas which is gasified from solid fossil fuels, etc, [1]

Boundary

5. The project boundary is the physical, geographical site of the industrial facility where the CHP or CCHP system is being implemented. The boundary also extends to the industrial facility consuming energy generated by the system and the processes or equipment that are affected by the project activity.

Baseline

6. One of the three following options for baseline emission calculations shall be used depending on the technology that would have been used to produce the heat/steam/hot air and power and where relevant cooling, in the absence of the project activity:

(a) Electricity is imported from the grid (includes the cooling load of a vapour compression system where relevant) and/or steam/heat is produced using fossil fuel;

(b) Electricity is produced in an onsite captive power plant (includes cooling load of a vapour compression system where relevant) and/or steam/heat/hot air is produced using fossil fuel;

(c) A combination of (a) and (b).

7. The appropriate baseline scenario must be selected from one of the following scenarios:

(a) Replacing existing systems: The project consists of the installation of a new system that replaces the operation of existing systems that supply electricity (grid or on-site generation) and cooling (e.g., chillers) and/or heating systems (e.g., boilers). In such cases the baseline scenario is defined as either:

(i) If the total annual consumption of energy (electricity, cooling and heating) by the consuming facility does not increase by more than 10% from the established baseline values during the crediting period then the baseline scenario is the existing systems and baseline emissions are established from the characteristics of the existing systems using data from the immediately prior three years (to the date of project start up);

(ii) If during the crediting period, total annual consumption of energy (electricity, cooling and heating) by the consuming commercial building does increase by more than 10% from the established baseline values then one of two options are applicable:

[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. Project activities that use gas that does not comply with this definition must apply for a revision of the methodology.

- If it can be demonstrated, using the related and relevant procedures prescribed in the SSC general guidance, that the most plausible baseline scenario for the supply of additional amounts of energy is the same as the existing systems then such systems can be continued to be used for determining baseline emissions;
- If it cannot be demonstrated that the most plausible baseline scenario for the supply of additional amounts of energy is the same as the existing systems then the Baseline Reference Plant Approach, as defined below shall be used;

(iii) If, irrespective of total annual energy consumption of baseline or project scenarios, it is determined that new and more efficient systems (as compared to the existing systems) would have been installed in the absence of the project activity (for example, due to the baseline equipment reaching the end of its useful life at any point during the crediting period) then the Baseline Reference Plant Approach, as defined below, shall be used;

(b) Replacing systems that would have been built: The project consists of the installation of a new system that replaces the operation of electricity and cooling and/or heating systems that would have been built and utilized. In such cases the Baseline Reference Plant Approach, as defined below, shall be used to define the baseline scenario.

Baseline Reference Plant Approach

In cases where the baseline scenario consists of the installation of new cooling and/or heating systems and/or the utilization of new electricity sources, a Reference Plant shall be defined as the baseline scenario. The Reference Plant shall be based on common practice for similar capacity, new heating and cooling systems and sources of electricity in the same industrial sector and in the same country or region as the project. The identification of the Reference Plant should exclude plants implemented as CDM project activities. In cases where no such plant exists within the country, the economically most attractive technology and fuel type should be identified among those which provide the same service (i.e., the same or similar power, heat and/or cooling capacity), that are technologically available, and that are in compliance with relevant regulations. The efficiency of the technology should be selected in a conservative manner, i.e., where several technologies could be used and are similarly economically attractive, the most efficient technology should be defined as the baseline scenario. In addition , the least carbon intensive fuel type should be chosen in case of multiple fuels being possible choices.

8. For each identified equipment that is/would be displaced by the project activity an assessment shall be carried out to determine:

(a) The remaining/expected service lifetime of the equipment as outlined in paragraph 9 below.

(b) The most appropriate baseline either:

(i) As the continuation of the operation of the equipment; or

(ii) As the installation of a new more efficient equipment that would have otherwise been installed in the absence of the project activity.

If it is identified that the baseline situation is the continuation of the operation of the existing installation, it should be demonstrated that the unit concerned has been in operation in the last three years.

(c) Historical relative contribution of the equipment to the total annual output of energy type concerned (power, steam/heat or cooling) based on the measured relative contribution over the last 3 years[2].

(d) In case the project activity displaces captive equipment(s), the baseline determined is only applicable up to the point in time when the concerned equipment needs to be replaced or is no longer fit for service $(DATE_{ServiceEnd})$. Beyond this time, it is assumed that the equipment will be replaced by an equipment analogous to the equipment installed in the project activity and thus from that point onwards the baseline emissions from this source are considered zero[3].

8. ~~In order to estimate the point in time where the existing equipment would be replaced in the absence of the project activity, project participants shall use the following approach:~~

~~(i) The typical average technical lifetime of the equipment concerned may be determined and documented on the basis of common practices in the sector and the country (e.g., based on industry surveys, statistics, technical literature, etc.).~~

~~(ii) The practices of the responsible company regarding replacement schedules may be evaluated and documented (e.g., based on historical replacement record of similar equipment).~~

~~(iii) For project activities employing CCHP technology, the service lifetime assessment should also take into account the applicable regulations in the host country regarding the phasing out of certain types of refrigerants.~~

[2] In case more than one captive system is generating a specific energy type (power, steam/heat or cooling) and one or more systems are being replaced in the project activity the relative contribution of these systems to the total output shall be taken into account in the formulas for baseline and project emissions. For example, if a project activity replaces two boilers, the first boiler delivers 2TJ and the second boiler 8TJ, the ratio of contribution by the individual boilers is 2/10 and 8/10 respectively. The formulas for baseline and project emission calculations shall be adjusted accordingly.

[3] For example, if a project activity displaces boiler "A" with service lifetime up to 2020, and an electrical chiller "B" with service lifetime up to 2015, then the baseline determined for the displacement of the boiler "A" is applicable up to 2020, whereas the determined baseline for displacing the electrical chiller "B" is applicable up to 2015. The baseline emissions for boiler "A" and chiller "B" beyond 2020 and 2015 respectively are considered zero.

~~The time of replacement of the existing equipment in the absence of the project activity should be chosen in a conservative manner, i.e., the earliest point in time should be chosen in cases where only a time frame can be estimated. The determination of this date shall be made on a case-by-case basis, for each piece of equipment that is being replaced.~~

9. The point in time at which the baseline systems would have been replaced in the absence of the project activity, and thus triggering the requirement for a new baseline scenario, shall be estimated in a conservative manner using the "Tool to determine the remaining lifetime of the equipment". The project activity shall be considered as one possible baseline scenario at the end of the useful life of existing equipment.

10. In the case of a project activity displacing a captive electricity generation plant and or grid electricity the baseline emissions are determined as follows:

(a) If the project activity generates electricity that displaces electricity previously obtained from the grid, the baseline emissions are the CO_2 emissions of the power plants connected to the grid. The baseline emissions $(BE_{elec,y})$ are then calculated based on the amount of grid electricity displaced by the project activity $(E_{grid,y}$ in MWh$)$ times the emission factor of the grid $(EF_{grid,y})$ calculated in accordance with methodology AMS-I.D.

$$BE_{elec,y} = E_{grid,y} * EF_{grid,y} \quad \textbf{(1)}$$

Where:

$BE_{elec,y}$	Baseline emissions for the grid electricity displaced by the project in year *y* (t CO_2e/year)
$E_{grid,y}$	Amount of grid electricity displaced by the project in year *y* (MWh)
$EF_{grid,y}$	Emission factor of the grid (calculated in accordance with methodology AMS-I.D. (tCO_2/MWh)

(b) If the project activity generates electricity that displaces electricity previously obtained from the operation of a captive power plant, the baseline emissions in year *y* $(BE_{elec,y})$ are calculated as the amount of electricity displaced $E_{grid,y}$ (in MWh) times the emission factor of the captive power plant.

$$BE_{elec,y} = E_{capt,y} * EF_{capt} \quad \textbf{(2)}$$

Where:

$BE_{elec,y}$	Baseline emissions for the amount of electricity displaced by the captive power plant in year *y* (t CO_2e/year)
$E_{capt,y}$	Amount of electricity displaced by the project activity in year *y* (MWh)

EF_{capt} Emission factor of the captive power plant (tCO_2/MWh)

The baseline emissions of the captive power plant are calculated up to $(DATE_{ServiceEnd})$.

(c) In case the project activity displaces electricity from a captive power plant as well as from the grid, then the emission factor for the displacement of electricity should reflect the emissions intensity of the captive power plant and the grid. The emission factor for the electricity displaced ($EF_{electricity}$) shall be calculated as the weighted average of captive electricity generation and the grid electricity[4]. For new facilities, the most conservative (lowest) emission factor of the two power sources should be used.

(d) The emission factor of the captive power plant (EF_{capt}) is calculated based on the specific fuel consumption[5] (quantity of fuel in thermal, mass or volume unit per unit electrical output) of the captive power plant (SFC_{cap}) determined as follows:

(i) For project activities displacing electricity previously obtained from the operation of existing captive power plants, the specific fuel consumption should be established based on historical measurement from the last 3 years;

(ii) For project activities displacing electricity from a captive power plant that otherwise would have been built, the specific fuel consumption (SFC_{cap}) is obtained from at least two manufacturers of equipment of similar specifications and a conservative value shall be used;

(iii) The emission factor for the captive power plant (EF_{capt}) is calculated as the product of the emission factor of fuel "*i*" used by the captive power plant ($COEF_i$) times SFC_{cap}; Equations 2, 3, or 4 contained in the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" shall be used for this purpose.

$$EF_{capt} = COEF_i * SFC_{cap} \quad \textbf{(3)}$$

Where:

SFC_{cap} Specific fuel consumption of the captive power plant (quantity of fuel in thermal, mass or volume unit/MWh)

[4] For example if in the baseline 80% of annual electricity requirement was met by grid import and the remaining by captive generation, the weighted average emission factor ($EF_{electricity}$) would be 0.8 EF_{grid} + 0.2 $EF_{captive}$.

[5] In case in the baseline situation more than one type of fossil fuel is used in the captive power plant, the relative contribution to the total output of each fossil fuel shall be considered and the formulas for baseline emissions shall be adjusted accordingly.

$COEF_i$	CO_2 emission coefficient of fuel type *i* (tCO_2 / quantity of fuel in thermal, mass or volume unit)

11. In the case of a project activity displacing a captive steam generation plant:

(a) The baseline emissions are calculated based on the equivalent amount of fuel that would have been used in the absence of the project activity. The baseline emissions of the captive steam generation plant can only be calculated up to $(DATE_{ServiceEnd})$.

(b) The equivalent amount of fuel (in thermal unit) that would have been consumed by the captive steam generation plant in year *y* (FC_y) is calculated using the efficiency of the displaced equipment (η_{cs}) and the project thermal energy delivery ($S_{p,y}$) using the following relationship:

$$FC_y = \frac{S_{p,y}}{\eta_{cs}} \tag{4}$$

Where:

FC_y	Equivalent amount of fuel that would have been consumed by the captive steam generation plant in year *y* (TJ)
η_{cs}	Efficiency of the displaced captive steam generation plant in year *y*
$S_{p,y}$	Thermal energy delivery of the project activity (TJ)

(c) The efficiency of the captive steam generation plant (η_{cs}) is determined as follow:

(i) If the displaced captive steam generation plant is an existing plant, the efficiency should be based on historical measurement of specific fuel consumption (for example, steam output per fuel input) using the data from the last three years;

(ii) If the displaced captive steam generation plant is a plant that would otherwise have been built in the absence of the project activity, the efficiency should be determined using one of the following options:

1. Highest measured efficiency of a unit with similar specifications;
2. Highest efficiency values provided by two or more manufacturers of equipment with similar specification;
3. Maximum efficiency of 100%.

(d) The baseline emissions associated with the combustion of fossil fuels, shall be calculated following the provisions specified in the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”.

12. In the specific case of project activities replacing a compression system chiller in the baseline by an absorption system chiller using engine exhaust gas, which does not need to generate intermediate steam as heat carrier before chilling can be generated, the baseline emissions are determined as follows:

(a) The baseline emissions are calculated up to $(DATE_{ServiceEnd})$. Baseline emissions are:

(i) Emissions from the electricity consumed to operate the baseline chiller, whether it is captive power or power from the grid; and

(ii) Emission associated with the physical leakage of refrigerants if the electrical chillers would have continued to be in service. This is only applicable if:

1. The displaced refrigerant is a greenhouse gas listed in Annex A of the Kyoto Protocol and;

2. The displaced chiller is an existing unit, and not an equipment that would otherwise been built.

The leakage rate shall be chosen in a conservative way.

(b) The amount of electricity consumed to operate the baseline chiller in year *y* ($E_{BC,y}$) is calculated based on the displaced chiller’s Coefficient of Performance (COP_c). The Coefficient of Performance is defined as ‘chilling output per electrical input’.

$$E_{BC,y} = \frac{C_{P,y}}{COP_c} \quad (5)$$

Where:

$E_{BC,y}$	Amount of electricity consumed to operate the baseline chiller in year *y* (MWh/year)
COP_c	The Coefficient of Performance of the displaced chiller (MWh_{th}/MWh)
$C_{p,y}$	Cooling output of the baseline chiller in year *y*(MWh_{th}/year)

(c) The coefficient of performance is determined as follow:

(i) If the displaced unit is an existing chiller, then the electricity consumed should be calculated based on the COP of the displaced chiller based on data from the last three years.

(ii) If the displaced unit is equipment that would otherwise have been built, the Coefficient of Performance shall be determined as follows:

1. The highest measured COP of a unit with similar specifications; or
2. The highest COP values provided by two or more manufacturer of equipment with similar specifications.

Manufacturers often do not directly specify the COP values but quote the chillers performance in tonnage of refrigerant (TR) per kW of electrical input. 1 TR is equivalent to the amount of heat absorbed by the melting of 1 ton of ice within 24 hours and is equivalent to 3.513 kW.

(d) The baseline emissions associated with electricity consumed to operate the baseline chiller is calculated using similar approach as per paragraph 910 of this methodology.

(e) The emissions associated with the leakage of refrigerant from the baseline chiller in year y ($BE_{LR,y}$) are calculated as a function of the historical specific leakage rate of the displaced chiller (SLR_C) times the global warming potential of the refrigerant concerned (GWP_j) using the following relationship:

$$BE_{LR,y} = SLR_C * GWP_j \quad \textbf{(6)}$$

Where:

$BE_{LR,y}$	The baseline emissions associated with the leakage of refrigerant from chiller in year y (t CO_2e/year)
SLR_C	The historical specific leakage rate of the displaced chiller (tonnes/year)
GWP_j	Global Warming Potential for refrigerant "j" in the baseline chiller

(f) The historical specific leakage rate of the displaced chiller (SLR_C) shall be based on historical charging records from at least the last 3 years. This value shall be compared to the default values provided in 2006 IPCC guidelines for national GHG inventories, volume 3, chapter 7, table 7.9. The lower of the two values i.e., IPCC default values and the leakage rates as determined from historical charging records shall be used.

(g) The total cooling output of the project activity per year in MJ ($C_{p,y}$) is calculated by measurement of the total chilled water mass flow-rate (m), differential temperature of incoming and outgoing water (ΔT) and the heat capacity of water ($C_{\rho w}$)

$$C_{p,y} = m * C_{\rho w} * \Delta T \quad \textbf{(7)}$$

Where:

m	The chilled water mass flow-rate in year y (tonnes/year)
$C_{\rho w}$	The specific heat capacity of water (MJ/tonnes °C) (liquid water 4.2 MJ/t °C)
ΔT	Differential temperature of incoming and outgoing water (°C)

Project activity emissions

13. The use of fossil fuels ~~and electricity~~ by the CHP or CCHP unit(s), including those to run auxiliary equipments, shall be monitored and accounted for as project emission in accordance with the 'Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" ~~and in case of electricity consumption from the grid, procedures of AMS-I.D shall be used.~~ Electricity consumption of project including any electricity used to run auxiliary equipment are calculated using the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption".

Leakage

14. Leakage is to be considered if the displaced energy generating equipment is transferred from another activity or the existing equipment is transferred to another activity.

15. In case of introduction of a CCHP system, if the displaced refrigerant is a greenhouse gas as defined in Annex A of the Kyoto Protocol or in paragraph 1 of the Convention and is not destroyed, leakage emission from its storage or usage in another equipment must be considered[6] and deducted from the emission reductions. As the measures covered in this methodology is limited to shift from chemical refrigerant to a refrigerant with no global warming potential and no ozone depleting potential, leakage due to production of refrigerant is not included.

Emission Reductions

16. The emission reduction achieved by the project activity shall be calculated as the difference between the baseline emissions and the sum of the project emissions and leakage.

Monitoring

17. Monitoring shall consists of:

[6] The global warming potentials used to calculate the carbon dioxide equivalence of anthropogenic emissions by sources of greenhouse gases not listed in Annex A of the Kyoto Protocol, shall be those accepted by the Intergovernmental Panel on Climate Change in its third assessment report.

(a) Documenting of the technical specification of the captive equipment displaced or equipment which would otherwise have been built.

~~(b)~~ The metering of all the relevant parameters should be as per the table.1 ~~electricity, cooling and steam outputs (net of internal consumption) generated by the CHP or CCHP utility and delivered to its users.~~

~~(i) The measurement of steam output is based on continuous monitoring of steam flow-rate, temperature and pressure.~~

~~(ii) The measurement of cooling output is based on continuous monitoring of chilled water flow-rate and the temperature difference between incoming and outgoing circulating water.~~

~~(iii) In the cases (e.g., hot air output) where it is justified that the continuous measurement of flow and temperature can not be done, its enthalpy can be determined through sampling with a 90% confidence level and a 10% precision following a procedure provided in "General Guidelines For Sampling And Surveys For Small-Scale CDM Project Activities".~~

~~(c) ©The metering of fossil fuel and electricity used in the project activity (including those to run auxiliary equipment and to use for supplementary/booster firing) shall be as mandated by 'Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" and in case of electricity use it shall be done as per the procedures of AMS-I.D. In case natural gas is used for energy generation, the amount of natural gas used shall be monitored continuously using gas flow meters.~~

~~(d) The parameters required to calculate the emission factor of the grid shall be monitored in accordance with the procedures of AMS-I.D.~~

~~(e) Necessary parameters are monitored to demonstrate that the measures implemented by the project activity are limited to activities that results in additional steam/heat and/or cooling generation capacity of no more than 5% of the pre-project situation.~~

Table 1: The following parameters shall be monitored and recorded during the crediting period.

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
1	$E_{grid,y}$	Amount of grid electricity displaced in year *y*	MWh/y	Continuous monitoring, hourly measurement and at least monthly recording	Measurements are undertaken using energy meters and calibration shall be as per the related and relevant paragraph of General guidelines to SSC methodologies. If applicable, measurement results shall be cross checked with records for sold/purchased electricity (e.g., invoices/receipts).
2	$E_{capt,,y}$	Amount of captive electricity displaced in year *y*	MWh/y	Continuous monitoring, hourly measurement and at least monthly recording	Measurements are undertaken using energy meters and calibration shall be as per the related and relevant paragraph of General guidelines to SSC methodologies. If applicable, measurement results shall be cross checked with records for sold/purchased electricity (e.g., invoices/receipts).
3	$EF_{grid, ,y}$	CO_2 emission factor for the grid electricity in year *y*	t CO_2e/kWh	Annually	Grid emission factor shall be determined following the provisions in AMS-I.D.

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II.H. Energy efficiency measures through centralization of utility provisions of an industrial facility (cont)

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
4	SLR_C	The historical specific leakage rate of the chiller displaced as a result of the installation of cogeneration or trigeneration plant *i*	tonnes/ year	Annually	Values taken from chiller maintenance record or purchase records of refrigerant. The value shall be cross-checked with the default values provided in 2006 IPCC guidelines for national GHG inventories, vol.3, chapter 7, table7.9
5	*m*	The chilled water mass flow-rate for chiller *i* produced by project in hour h of year *y*	tonnes/ hour	Continuous, integrated hourly, at least monthly recording	Measured using calibrated meters. Calibration shall be as per the related and relevant paragraph of General guidelines to SSC methodologies.
6	ΔT	Differential temperature for chiller *i* in hour h of year *y* of incoming and outgoing water from project	°C	Continuous, integrated hourly, atleast monthly recording	Measured using calibrated meters. Calibration shall be as per the related and relevant paragraph of General guidelines to SSC methodologies.

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II.H. Energy efficiency measures through centralization of utility provisions of an industrial facility (cont)

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
7	$S_{p,y}$	Thermal energy delivered by the project activity in year *y*	TJ/y	Continuous, integrated hourly, at least monthly recording	Measured using calibrated meters. Calibration shall be as per the related and relevant paragraph of General guidelines to SSC methodologies. Thermal energy production is determined as the difference of the enthalpy of the steam or hot water generated by the heat generation equipment and the sum of the enthalpies of the feed-fluid and any condensate returns. 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 case of equipment that produces hot water/oil this is expressed as difference in the enthalpy between the hot water/oil supplied to and returned by the plant. In case the project activity is exporting heat to other facilities, the metering shall be carried out at the recipient's end.

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II.H. Energy efficiency measures through centralization of utility provisions of an industrial facility (cont)

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
8	*T*	Temperature	°C	Continuous monitoring, hourly measurement and at least monthly recording	Measured using calibrated meters. Calibration shall be as per the related and relevant paragraph of General guidelines to SSC methodologies. In the cases (e.g., hot air output) where it is justified that the continuous measurement of flow and temperature can not be done, its enthalpy can be determined through sampling with a 90% confidence level and a 10% precision following a procedure provided in "General Guidelines For Sampling And Surveys For Small-Scale CDM Project Activities"
9	*P*	Pressure	kg/cm^2	Continuous monitoring, hourly measurement and at least monthly recording	Measured using calibrated meters. Calibration shall be as per the related and relevant paragraph of General guidelines to SSC methodologies. In the cases (e.g., hot air output) where it is justified that the continuous measurement of flow and temperature can not be done, its enthalpy can be determined through sampling with a 90% confidence level and a 10% precision following a procedure provided in "General Guidelines For Sampling And Surveys For Small-Scale CDM Project Activities"
10		Quantity of fossil fuel type *j* combusted in year *y*	Mass or volume unit	As per the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"	As per the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion."

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
11		Quantity of grid electricity consumed in year *y*	MWh/y	As per "Tool to calculate baseline, project and/or leakage emissions from electricity consumption".	As per "Tool to calculate baseline, project and/or leakage emissions from electricity consumption".

Project activity under a programme of activities

~~The following conditions apply for use of this methodology in a project activity under a programme of activities:~~

18. Leakage emissions resulting from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary shall be considered, as per the guidance provided in the leakage section of ACM0009. In case leakage emissions in the baseline situation are higher than leakage emissions in the project situation, leakage emissions will be set to zero.

~~19. In case the project activity involves the replacement of equipment, and the leakage effect of the use of the replaced equipment in another activity is neglected, because the replaced equipment is scrapped, an independent monitoring of scrapping of replaced equipment needs to be implemented. The monitoring should include a check if the number of project activity equipment distributed by the project and the number of scrapped equipment correspond with each other. For this purpose scrapped equipment should be stored until such correspondence has been checked. The scrapping of replaced equipment should be documented and independently verified.~~

~~20. Leakage resulting from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary shall be considered. The guidance provided in the leakage section of ACM0009 as in annex 1 of this document shall be followed for this purpose.~~

Annex 1

(GUIDANCE ON LEAKAGE BELOW CONCERNS PROJECT ACTIVITY UNDER A PROGRAMME OF ACTIVITIES)

Leakage

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered:[7]

- Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity.
- In the case LNG is used in the project plant: CO_2 emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \qquad (1)$$

Where:

LE_y	Leakage emissions during the year y in t CO_2e
$LE_{CH4,y}$	Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_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 during the year y in t CO_2e

Note that 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.

Fugitive methane emissions

For the purpose of determining fugitive methane emissions associated with the production – and in case of natural gas, the transportation and distribution of the fuels – project participants should multiply the quantity of natural gas consumed in all element processes *i* with a methane emission factor for these upstream emissions ($EF_{NG,upstream,CH4}$), and subtract for all fuel types *k* which would

[7] The Meth Panel is undertaking further work on the estimation of leakage emission sources in case of fuel switch project activities. This approach may be revised based on outcome of this work.

be used in the absence of the project activity the fuel quantities multiplied with respective methane emission factors ($EF_{k,upstream,CH4}$), as follows:

$$LE_{CH4,y} = \left[FF_{project,y} \cdot NCV_{NG,y} \cdot EF_{NG,upstream,CH4} - \sum_k FF_{baseline,k,y} \cdot NCV_k \cdot EF_{k,upstream,CH4} \right] \cdot GWP_{CH4} \quad (2)$$

with

$$FF_{project,y} = \sum_i FF_{project,i,y} \quad \text{and} \quad (3)$$

$$FF_{baseline,k,y} = \sum_i FF_{baseline,i,k,y} \quad (4)$$

Where:

$L_{CH4,y}$	Leakage emissions due to upstream fugitive CH_4 emissions in the year y in t CO_2e
$FF_{project,y}$	Quantity of natural gas combusted in all element processes during the year *y* in m^3
$FF_{project,i,y}$	Quantity of natural gas combusted in the element process *i* during the year *y* in m^3
$NCV_{NG,y}$	Average net calorific value of the natural gas combusted during the year *y* in MWh/m^3
$EF_{NG,upstream,CH4}$	Emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas in t CH_4 per MWh fuel supplied to final consumers
$FF_{baseline,k,y}$	Quantity of fuel type *k* (a coal or petroleum fuel type) that would be combusted in the absence of the project activity in all element processes during the year *y* in a volume or mass unit
$FF_{baseline,i,k,y}$	Quantity of fuel type *k* (a coal or petroleum fuel type) that would be combusted in the absence of the project activity in the element process *i* during the year *y* in a volume or mass unit
NCV_k	Average net calorific value of the fuel type *k* (a coal or petroleum fuel type) that would be combusted in the absence of the project activity during the year *y* in MWh per volume or mass unit
$EF_{k,upstream,CH4}$	Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or petroleum fuel type) in t CH_4 per MWh fuel produced
GWP_{CH4}	Global warming potential of methane valid for the relevant commitment period

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.[8] Where such data is not available, project participants may use the default values provided in Table 2 below. In this case, the natural gas emission factor for the location of the project should be used, except in cases where it can be shown that the relevant system element (gas production and/or processing/transmission/distribution) is predominantly of recent vintage and built and operated to international standards, in which case the US/Canada values may be used.~~

~~Note that the emission factor for fugitive upstream 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. Note further that in case of coal the emission factor is provided based on a mass unit and needs to be converted in an energy unit, taking into account the net calorific value of the coal.~~

[8] ~~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.~~

Indicative simplified baseline and monitoring methodologies
for selected small-scale CDM project activity categories

II.H. Energy efficiency measures through centralization of utility provisions of an industrial facility (cont)

Table 2: Default emission factors for fugitive CH_4 upstream 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.

CO_2 emissions from LNG

Where applicable, CO_2 emissions from fuel combustion / electricity 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:

$$LE_{LNG,CO2,y} = FF_{project,y} \cdot EF_{CO2,upstream,LNG} \quad (5)$$

Where:

$LE_{LNG,CO2,y}$	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 during the year y in t CO_2e
$FF_{project,y}$	Quantity of natural gas combusted in all element processes during the year *y* in 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

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 t CO_2/TJ as a rough approximation.[9]

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History of the document

Version	Date	Nature of revision
02	EB xx, Annex # dd mm 2010	To include Greenfield project activities and provide options for sample based monitoring of thermal energy output.
01	EB 38, Annex 8, 14 March 2008	Initial adoption.

[9] 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)".