Draft consolidated baseline and monitoring methodology ACM00XX

"Construction of a new natural gas power plant supplying electricity to the grid or a single consumer"

I. SOURCE, DEFINITIONS AND APPLICABILITY

Sources

This consolidated baseline and monitoring methodology is based on the following approved baseline and monitoring methodology and proposed new methodologies:

- AM0029: Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas;
- NM0080-rev: Baseline methodology for grid connected generation plants using non-renewable and less GHG intensive fuel submitted by Torrent Power Generation Limited (TPGL) and assisted by PricewaterhouseCoopers (PwC);
- NM0153: Baseline methodology for grid connected electricity generation plants using Natural Gas (NG)/Liquiefied Natural Gas (LNG) as fuels submitted by Reliance Energy Limited (REL); and
- NM0322: Provision of natural gas-based electricity to a single user from a new plant owned and operated by the power supplier submitted by PT Carbon Partners Asiatica.

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

- Tool to calculate the emission factor for an electricity system;
- Tool to determine the baseline efficiency of thermal or electric energy generation systems;
- Tool for the demonstration and assessment of additionality; and
- Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion.

For more information regarding the proposed new methodologies and the tools as well as their consideration by the CDM Executive Board (the Board) please refer to <http://cdm.unfccc.int/goto/MPappmeth>.

Selected approach from paragraph 48 of the CDM modalities and procedures

"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:

New power plant[1] is a newly constructed power plant with no operational history.

Electricity consuming facility is a single industrial or commercial facility that is connected to the electric power grid and meets its electricity demand under the project activity with electricity from (i) the project activity power plant and, where applicable, in addition from (ii) a captive power plant operated at the site of the electricity consuming facility and/or (iii) the electric power grid.[2]

Captive power plant is a power plant operated at the site of the electricity consuming facility, including any back-up power generators.

Natural gas is a gas which is consisting primarily of methane and which is generated from (i) natural gas fields (non-associated gas), (ii) associated gas found in oil fields and/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 biodigesters, gas from coal mines, gas which is gasified from solid fossil fuels, etc,[3] .

In addition, the definitions in the latest approved version of the "Tool to calculate the emission factor for an electricity system" apply.

Applicability

This consolidated methodology is applicable to project activities that implement new power generation plants that use natural gas as fuel, and displace electricity from the electric power grid or from a specific baseline power generation technology.

This methodology is applicable under the following conditions:

- The project activity is the construction and operation of a new natural gas fired power plant that supplies electricity (i) to the electric power grid, and/or (ii) to an existing electricity consuming facility that is also connected to the electric power grid;
- The project activity power plant generates only electricity and does not co-generate heat;
- No power was generated at the site of the new power plant prior to the implementation of the CDM project activity;
- Natural gas is used as main fuel in the project power plant. Small amounts of other start-up or auxiliary fuels can be used, but they shall not comprise more than 3% of total fuel used annually, on an energy basis;
- Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity.[4]

---

1 Power plant is defined as per the "Tool to calculate the emission factor for an electricity system".

2 Grid is defined as per the "Tool to calculate the emission factor for an electricity system".

3 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.

4 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

In the case that the project plant supplies electricity to an existing electricity consuming facility, the following further conditions apply:

- The electricity consuming facility has an operation history of at least three years;
- The project plant supplies electricity to the electricity consuming facility through a dedicated electric line which is not used for other purposes.

Finally, the methodology is only applicable if the most plausible baseline scenario, as identified per the "Procedure for the selection of the baseline scenario" section hereunder, is P2 or P6 and, in the case that power is supplied to an electricity consuming facility, in combination with scenarios C2, C3, C4 or C5.

II. BASELINE METHODOLOGY PROCEDURE

Project boundary

The spatial extent of the project boundary includes the project power plant, all power plants connected physically to the electric power grid as defined in the "Tool to calculate emission factor for an electricity system" and, in the case that the project activity power plant exports electricity to a consuming facility, the electricity consuming facility.

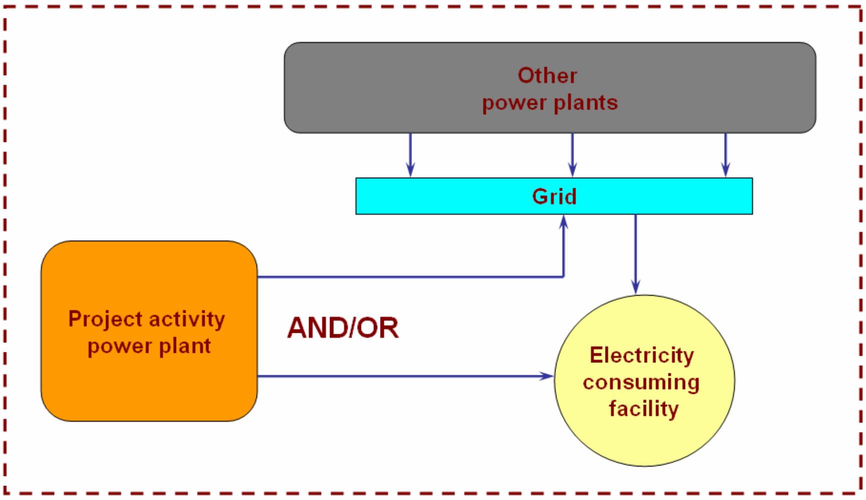

Figure 1. Project boundary

In the calculation of project emissions, only CO_2 emissions from fossil fuel combustion in the project power plant are considered. In the calculation of baseline emissions, only CO_2 emissions from fossil fuel combustion in power plant(s) in the baseline are considered.

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

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.

Table 1: Overview of emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Power generation	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification. This is conservative
		N_2O	No	Excluded for simplification. This is conservative
Project Activity	Fuel combustion in the project plant	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification
		N_2O	No	Excluded for simplification

Procedure for the selection of the baseline scenario

Project participants shall apply the following steps to define the baseline scenario:

Step 1: Identify plausible baseline scenarios

Identify plausible alternative baseline scenarios by applying Step 1 of the latest version of the "Tool for the demonstration and assessment of additionality" approved by the Board.

Alternatives to be analysed should include, *inter alia*:

P1 The construction of one or several other power plant(s) using natural gas, but technologies other than the project activity;

P2 The construction of one or several other power plant(s) using fossil fuels other than natural gas;

P3 The construction of one or several other power plant(s) using renewable power generation technologies;

P4 Import of electricity from connected grids;

P5 The project activity not implemented as a CDM project;

P6 No construction of a new power plant by the project participants but generation of power in the grid in existing and new power plants.

These alternatives do not need to consist solely of power plants of the same capacity, load factor and operational characteristics (i.e. several smaller plants, or the share of a larger plant may be a reasonable alternative to the project activity), however they should deliver similar services (e.g. peak- vs. base-load power). Ensure that all relevant power plant technologies that have recently been constructed or are under construction or are being planned by the project participants are included as plausible alternatives.

If the project plant supplies electricity to an electricity consuming facility, alternatives to be analyzed for this facility should include, *inter alia*:

C1 The project activity not implemented as a CDM project;

C2 The construction of one or several captive power plants at the site of the electricity consuming facility;

C3 The continued operation of one or several captive power plants at the site of the electricity consuming facility;

C4 Purchase of electricity from the grid;

C5 A combination of one or several new and/or existing captive power plants operated at the site of the electricity consuming facility and purchase of electricity from the grid;

C6 Purchase of electricity from another dedicated off-site power plant.

In considering these scenarios, it should be ensured that the same service is provided to the electricity consuming facility (i.e. the electricity demand of the facility should be met in all scenarios).

A clear description of each baseline scenario alternative, including information on the technology, such as the efficiency and technical lifetime, shall be provided in the CDM-PDD.

If one or more scenarios are excluded, an appropriate explanation and documentation to support the exclusion of such scenario shall be provided in the CDM-PDD.

If the project plant supplies electricity to an electricity consuming facility, realistic combinations of scenarios for power generation by the project participants (P) and consumption of power by the electricity consuming facility (C) should be considered in the subsequent steps.

Step 2: Identify the economically most attractive baseline scenario alternative

The economically most attractive baseline scenario alternative is identified using an investment comparison analysis, by applying Step 2 (Option II) of the latest version of the "Tool for the demonstration and assessment of additionality" approved by the Board. Calculate a suitable financial indicator for all alternatives remaining after Step 1. Include all (i) relevant costs (including, for example, the investment cost, fuel costs and operation and maintenance costs), (ii) revenues (including subsidies/fiscal incentives,[5] ODA, etc, where applicable) and, as appropriate, (iii) non-market costs and benefits in the case of public investors.

The investment analysis should be presented in a transparent manner and all relevant assumptions should be provided in the CDM-PDD, so that a reader can reproduce the analysis and obtain the same results. Critical techno-economic parameters and assumptions (such as capital costs, fuel price projections, lifetimes, the load factor of the power plant, and discount rate or cost of capital) should be clearly presented. Justify and/or cite assumptions in a manner that can be validated by the DOE. In calculating the financial indicator, the risks of the alternatives can be included through the cash flow pattern, subject to project-specific expectations and assumptions (e.g. insurance premiums can be used in the calculation to reflect specific risk equivalents). Where assumptions, input data, and data sources for the investment analysis differ across the project activity and its alternatives, differences should be well substantiated.

The CDM-PDD submitted for validation shall present a clear comparison of the financial indicator for all scenario alternatives. The baseline scenario alternative that has the best indicator can be pre-selected as the most plausible baseline scenario; then a sensitivity analysis shall be performed for all alternatives. The range of the sensitivity analysis should cover, in a realistic way, the possible variations of all key parameters that are related to the analysis and that could change over the crediting period.

[5] Note the guidance by EB 22 on national and/or sectoral policies and regulations.

A sensitivity analysis shall be performed for all alternatives, to confirm that the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions (e.g. fuel prices and the load factor). The investment analysis provides a valid argument in selecting the baseline scenario only if it consistently supports (for a realistic range of assumptions) the conclusion that the pre-selected baseline scenario is likely to remain the most economically and/or financially attractive.

If sensitivity analysis confirms the result, then select the most economically attractive alternative as the most plausible baseline scenario. In case the sensitivity analysis is not fully conclusive, select the baseline scenario alternative with the lowest emission rate among the alternatives that are the most financially and/or economically attractive.

Procedure for the demonstration of additionality

For the demonstration of additionality the following steps shall be applied:

Step 1: Benchmark investment analysis

Demonstrate that that the proposed CDM project activity is unlikely to be financially attractive by applying Sub-steps 2b (Option III: Apply benchmark analysis), Sub-step 2c (Calculation and comparison of financial indicators), and 2d (Sensitivity Analysis) of the latest version of the “Tool for demonstration assessment and of additionality” approved by the Board.

Step 2: Common practice analysis

Demonstrate that the project activity is not common practice in the relevant country and sector by applying Step 4 (common practice analysis) of the latest version of the “Tool for demonstration assessment and of additionality” approved by the Board.

If both steps above are satisfied, then the project is considered additional.

Emission Reductions

Annual emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \qquad \textbf{(1)}$$

Where:

ER_y	=	Emissions reductions in year y (tCO_2e)
BE_y	=	Baseline emissions in year y (tCO_2)
PE_y	=	Project emissions in year y (tCO_2)
LE_y	=	Leakage emissions in year y (tCO_2e)

Baseline Emissions

Baseline emissions are (BE_y) calculated by multiplying the electricity supplied by the project plant to the grid and/or the electricity consuming facility ($EG_{PJ,y}$) with a baseline CO_2 emission factor ($EF_{BL,CO2,y}$), as follows:

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y} \quad \textbf{(2)}$$

Where:

BE_y	=	Baseline emissions in year *y* (tCO_2)
$EG_{PJ,y}$	=	Quantity of electricity generated in the project power plant that is fed into the grid and/or supplied to the electricity consuming facility in year *y* (MWh)
$EF_{BL,CO2,y}$	=	CO_2 emission factor for electricity generation in the baseline in year *y* (tCO_2/MWh)

Determination of $EF_{BL,CO2,y}$

For construction of large new power capacity additions under the CDM, there is a considerable uncertainty relating to which type of other power generation is substituted by the power generation of the project plant. As a result of the project, the application of an alternative power generation technology(s) could be avoided, or the construction of a series of other power plants could simply be delayed. Furthermore, if the project were installed sooner than these other projects might have been constructed, its near-term impact could be largely to reduce electricity generation in existing plants. This depends on many factors and assumptions (e.g. whether there is a supply deficit) that are difficult to determine and that change over time. Similarly, in the case of new power plants supplying electricity to an electricity consuming facility which is also connected to the electric power grid, there is high level of uncertainty on whether the new power plant would displace an existing or new to be built captive power plant or electricity from the electric power grid. In order to address this uncertainty in a conservative manner, project participants shall use for the parameter $EF_{BL,CO2,y}$ the lowest emission factor in tCO_2/MWh among the following three options:

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

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

Option 3. If applicable, the lowest among the emission factors of (a) the technology and fuel, identified as the most likely baseline scenario under “Identification of the baseline scenario” above, and, if applicable, (b) the emission factor of existing or new captive power plant(s)[6] (i.e. scenarios C2, C3 or C5). The emission factor is to be calculated as follows ($EF_{BL,CO2,y} = EF_{BL,Tech,CO2}$):

$$EF_{BL,Tech,CO2} = \frac{COEF_{BL}}{\eta_{BL}} \cdot 3.6 \quad \textbf{(3)}$$

Where:

$EF_{BL,Tech,CO2}$	=	Emission factor of the baseline technology and fuel (tCO_2/MWh)
$COEF_{BL}$	=	The fuel emission coefficient of the baseline fuel (tCO_2/GJ)
η_{BL}	=	The energy efficiency of the baseline technology (ratio)
3.6	=	Conversion factor from GJ to MWh (GJ/MWh)

[6] In case that more than one captive power plant exists at the site of the electricity consuming facility, the lowest emission factor among these shall be used.

In case that Option 3 is selected, the determination of $EF_{BL,CO2,y}$ is to be made once at the validation stage based on an *ex ante* assessment. In the case of existing captive power plants, the parameter η_{BL} should be determined using the latest version of the "Tool to determine the baseline efficiency of thermal or electric energy generation systems" approved by the Board. The tool should be used to determine a constant efficiency and not a load-efficiency function. In the case of new power plants, the parameter η_{BL} corresponds to the maximum efficiency of the baseline technology at the optimal operating conditions, as supported by the manufacturer of this technology.

If either Option 1 (BM) or Option 2 (CM) are selected, $EF_{BL,CO2,y}$ is to be monitored *ex post* as described in "Tool to calculate the emission factor for an electricity system".

Project emissions

Project emissions result from the combustion of natural gas and small amounts of other start-up or auxiliary fuels for the generation of electricity in the project power plant. To calculate the project emissions (PE_y), the latest approved version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" is to be applied. 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 project activity power 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:[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, in the baseline scenario, in power plants connected to the grid and, if applicable, the baseline power plant (Option 3 above);
- 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
- In the case that LNG is used in the project plant, CO_2 emissions are to be accounted for due to fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, the leakage emissions are calculated as follows:

[7] The Board 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.

$$LE_y = LE_{CH4,y} + LE_{CO2,y} + LE_{LNG,CO2,y} \quad \textbf{(4)}$$

Where:

LE_y	=	Leakage emissions in the year *y* (tCO_2e)
$LE_{CH4,y}$	=	Leakage emissions due to fugitive upstream 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_2)
$LE_{LNG,CO2,y}$	=	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)

Fugitive methane emissions ($LE_{CH4,y}$)

For the purpose of estimating fugitive CH_4 emissions, project participants should multiply the quantity of natural gas consumed by the project in year *y* with an emission factor for fugitive CH_4 emissions ($EF_{NG,upstream,CH4}$) from natural gas consumption and subtract the emissions occurring from fossil fuels used in the absence of the project activity, as follows:

$$LE_{CH4,y} = \left[FC_{NG,y} \cdot NCV_{NG,y} \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4,y}\right] \cdot GWP_{CH4} \quad \textbf{(5)}$$

Where:

$LE_{CH4,y}$	=	Leakage emissions due to fugitive upstream CH_4 emissions in year *y* (tCO_2e)
$FC_{NG,y}$	=	Quantity of natural gas combusted in the project plant in year *y* (m^3)
$NCV_{NG,y}$	=	Average net calorific value of the natural gas combusted during the 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)
$EG_{PJ,y}$	=	Quantity of electricity generated in the project power plant that is fed into the grid and/or supplied to the electricity consuming facility in year *y* (MWh)
$EF_{BL,upstream,CH4,y}$	=	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity power plant in year *y* (tCH_4/MWh)
GWP_{CH4}	=	Global warming potential of methane valid for the relevant commitment period (tCO_2e/tCH_4)

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL,upstream,CH4,y}$) should be calculated consistent with the baseline emission factor ($EF_{BL,CO2}$) selected above, as follows:

Option 1: Build Margin

$$EF_{BL,upstream,CH4,y} = \frac{\sum_j \sum_k FF_{j,k,y} \cdot NCV_{j,k,y} \cdot EF_{k,upstream,CH4}}{\sum_j EG_{j,y}}$$

Option 2: Combined Margin

$$EF_{BL,upstream,CH4,y} = 0.5 \cdot \frac{\sum_j \sum_k FF_{j,k,y} \cdot NCV_{j,k,y} \cdot EF_{k,upstream,CH4}}{\sum_j EG_{j,y}} + 0.5 \cdot \frac{\sum_i \sum_k FF_{i,k,y} \cdot NCV_{i,k,y} \cdot EF_{k,upstream,CH4}}{\sum_i EG_{i,y}}$$

Option 3: Baseline technology

$$EF_{BL,upstream,CH4,y} = \frac{EF_{k,upstream,CH4}}{h_{BL}} * 3.6$$

Where:

$EF_{BL,upstream,CH4,y}$	=	Emission factor for upstream fugitive methane 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 methane 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)
η_{BL}	=	The energy efficiency of the baseline technology (ratio)

If $EF_{BL,upstream,CH4,y}$ is determined based on Options 1 or 2, 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". In case that Option 3 is selected, the determination of $EF_{BL,upstream,CH4,y}$ is to be made once at the validation stage based on an *ex ante* assessment.

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 should use the default values provided in Table 2 below.

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. Where default values from this table are used, the natural gas emission factors for the location of the project activity should be used. The US/Canada values may be used 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.

[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.

Since the fugitive upstream emissions for coal depends on the source (underground or surface mines), project participants should use the emission factor that corresponds to the predominant source (underground or surface) currently used by coal-based power plants in the region.

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. Moreover, all values used from Table 2 are to be converted to the appropriate units in order to be correctly used in the equations provided in this methodology.

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.

Upstream emissions due to CO_2 removal from raw natural gas stream ($LE_{CO2,y}$)

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 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:

$$LE_{CO2,y} = FC_{NG,y} \cdot \frac{r_{CO2}}{1 - r_{CO2}} \cdot \rho_{CO2} \quad \textbf{(6)}$$

Where:

$LE_{CO2,y}$	=	Leakage emissions due to the removal of CO_2 from the raw natural gas stream in year y (tCO_2)
$FC_{NG,y}$	=	Quantity of natural gas combusted in the project plant in year y (m^3)
r_{CO2}	=	Average CO_2 content in the raw natural gas stream on volume basis (ratio)
ρ_{CO2}	=	Density of CO_2 under standard conditions (tonnes/m^3)

CO_2 emissions from LNG ($LE_{LNG,CO2,y}$)

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:

$$LE_{LNG,CO2,y} = FC_{NG,y} \cdot NCV_{NG,y} \cdot EF_{CO2,upstream,LNG} \quad \textbf{(7)}$$

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 in year y (tCO_2e)
$FC_{NG,y}$	=	Quantity of natural gas combusted in the project plant in year y (m^3)
$NCV_{NG,y}$	=	Average net calorific value of the natural gas combusted in year y (GJ/m^3)
$EF_{CO2,upstream,LNG}$	=	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/GJ)

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_{2e}/TJ as a rough approximation[9] (this value has to be converted to the appropriate units in order to be correctly used in the equations provided in the methodology).

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

Data and parameters not monitored

In addition to the parameters listed in the tables below, the provisions on data and parameters not monitored in the tools referred to in this methodology apply.

<table>
<tr><td>Data / Parameter:</td><td>$COEF_{BL}$</td></tr>
<tr><td>Data unit:</td><td>tCO_2/GJ</td></tr>
<tr><td>Description:</td><td>The fuel emission coefficient of the baseline fuel</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 in the case of an existing captive power plant</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>Applicable to existing captive power plants if (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>For new power plants or if (a) is not available

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>For new power plants or if (a) is not available</td></tr>
</table>
</td></tr>
</table>

[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)".

Measurement procedures (if any):	For (a) and (b): Measurements should be undertaken in line with national or international fuel standards
Any comment:	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

Data / Parameter:	η_{BL}
Data unit:	ratio
Description:	The energy efficiency of the baseline technology
Source of data:	In the case of existing captive power plants, use the latest version of the "Tool to determine the baseline efficiency of thermal or electric energy generation systems" approved by the Board. The tool should be used to determine a constant efficiency and not a load-efficiency-function. In the case of new power plants, use the maximum efficiency of the baseline technology at the optimal operating conditions, as supported by the manufacturer of this technology
Measurement procedures (if any):	-
Any comment:	-

Data / Parameter:	GWP_{CH4}
Data unit:	$tCO2_e/tCH4$
Description:	Global warming potential of methane valid for the relevant commitment period
Value to be applied:	Default value of 21 for the first commitment period under the Kyoto Protocol
Measurement procedures (if any):	-
Any comment:	-

Data / parameter:	$EF_{NG,upstream,CH4}$
Data unit:	tCH4/GJ
Description:	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
Source of data:	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. Where such data is not available, project participants should use the default values provided in the Table 2 in the baseline methodology
Measurement procedures (if any):	-
Any comment:	-

Data / Parameter:	$EF_{k,upstream,CH4}$
Data unit:	tCH4/GJ
Description:	Emission factor for upstream fugitive methane emissions from production of the fuel type *k* (a coal or oil type)
Source of data:	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. Where such data is not available, project participants should use the default values provided in the Table 2 in the baseline methodology
Measurement procedures (if any):	-
Any comment:	-

Data / Parameter:	$EF_{CO2,upstream,LNG}$
Data unit:	$tCO2_e$/GJ
Description:	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
Source of data:	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 tCO2e/TJ as a rough approximation
Measurement procedures (if any):	-
Any comment:	-

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

Data / Parameter:	ρ_{CO2}
Data unit:	tonnes/m^3
Description:	Density of the CO_2 gas under standard conditions
Value to be applied:	A default value of 0.001978 t CO_2 / m_3 CO_2 under standard conditions
Measurement procedures (if any):	-
Any comment:	-

III. MONITORING METHODOLOGY

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 2 years after the end of the last crediting period. 100% 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, $FC_{NG,y}$ 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, $FF_{j,k,y}$, $FF_{i,k,y}$, $NCV_{j,k,y}$, $NCV_{i,k,y}$, $EG_{j,y}$, $EG_{i,y}$, should be determined as per the "Tool to calculate the emission factor for an electricity system".

Data and parameters monitored

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh
Description:	Quantity of electricity generated in the project power plant that is fed into the grid and/or supplied to the electricity consuming facility in year *y*
Source of data:	Onsite measurements
Measurement procedures (if any):	Use electricity meters installed at the grid interface for electricity export to grid and for supply to captive consumers use electricity meters installed at the entrance of the electricity consuming facility (battery limits)
Monitoring frequency:	Continuously, aggregated at least annually
QA/QC procedures:	Cross check measurement results with records for sold electricity
Any comment:	-

IV. REFERENCES AND ANY OTHER INFORMATION

Not applicable.

-.-.-.-.-.

History of the document

Version	Date	Nature of revision(s)
01	EB 53, Annex # 26 March 2010	To be considered at EB 53.
Decision Class: Regulatory **Document Type**: Standard **Business Function**: Methodology		