Approved baseline methodology AM0029

"Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas"

Sources

This baseline methodology is based on the proposals NM0080-rev "Baseline methodology for grid connected generation plants using non-renewable and less GHG intensive fuel" and NM0153 "Baseline methodology for grid connected electricity generation plants using Natural Gas (NG)/Liquiefied Natural Gas (LNG) as fuels" submitted by Torrent Power Generation Limited (TPGL), assisted by PricewaterhouseCoopers (P), and Reliance Energy Limited (REL) respectively.

For more information regarding the proposal and its consideration by the Executive Board please refer to <http://cdm.unfccc.int/methodologies/approved>.

This methodology also uses the build margin (BM) and operating margin (OM) approach as specified in "Tool to calculate emission factor for an electricity system" and makes reference to the latest approved version of the "Tool for the demonstration and assessment of additionality".

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"

Applicability

The methodology is applicable under the following conditions:

- The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant;[1]
- The geographical/physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available;
- 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.[2]

This baseline methodology shall be used in conjunction with the approved monitoring methodology AM0029.

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[1] Natural gas should be the primary fuel. Small amounts of other startup or auxiliary fuels ~~should~~can be used, but can comprise no more than 1% of total fuel use, on energy basis.

[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 proponent to document that supply limitations will not result in significant leakage as indicated here.

Identification of the baseline scenario

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

1. Identify plausible baseline scenarios

The identification of alternative baseline scenarios should include all possible realistic and credible alternatives that provide outputs or services comparable with the proposed CDM project activity (including the proposed project activity without CDM benefits), i.e., all type of power plants that could be constructed as alternative to the project activity within the grid boundary (as defined in "Tool to calculate emission factor for an electricity system").

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

- The project activity not implemented as a CDM project;
- Power generation using natural gas, but technologies other than the project activity;
- Power generation technologies using energy sources other than natural gas;
- Import of electricity from connected grids, including the possibility of new interconnections.

These alternatives need not 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. baseload power). Note further that the baseline scenario candidates identified may not be available to project participants, but could be other stakeholders within the grid boundary (e.g. other companies investing in power capacity expansions). Ensure that all relevant power plant technologies that have recently been constructed or are under construction or are being planned (e.g. documented in official power expansion plans) are included as plausible alternatives. 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.

The project participant may exclude baseline scenarios that are not in compliance with all applicable legal and regulatory requirements.

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

2. Identify the economically most attractive baseline scenario alternative

The economically most attractive baseline scenario alternative is identified using investment analysis. ~~The levelized cost of electricity production in $/kWh should be used as financial indicator for investment analysis.~~ Calculate ~~a~~the suitable financial indicator for all alternatives remaining after Step 1. Include all relevant costs (including, for example, the investment cost, fuel costs and operation and maintenance costs), and revenues (including subsidies/fiscal incentives,[3] ODA, etc. where applicable), and, as appropriate, non-market costs and benefits in the case of public investors.

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[3] Note the guidance by EB22 on national and/or sectoral policies and regulations.

The investment analysis should be presented in a transparent manner and all the 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 (e.g. highest IRR) 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.

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.

If the emission rate of the selected baseline scenario is clearly below that of the project activity (e.g. the baseline scenario is hydro, nuclear or biomass power), then the project activity should not be considered to yield emission reductions, and this methodology cannot be applied.

Additionality

The assessment of additionality comprises the following steps:

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" agreed by the CDM Executive 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" agreed by the CDM Executive Board.

Step 3: Impact of CDM registration

Describe the impact of the registration of the project activity by applying Step 5 (Impact of CDM registration) of the latest version of the "Tool for demonstration assessment and of additionality" agreed by the CDM Executive Board.

If all 3 steps are satisfied, then the project is considered additional.

Project boundary

The spatial extent of the project boundary includes the project site and all power plants connected physically to the baseline grid as defined in "Tool to calculate emission factor for an electricity system".

In the calculation of project emissions, only CO_2 emissions from fossil fuel combustion at the project 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.

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

	Source	Gas	Included?	Justification / Explanation
Baseline	Power generation in baseline	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	On-site fuel combustion due to the project activity	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification
		N_2O	No	Excluded for simplification.

Project emissions

The project activity is on-site combustion of natural gas to generate electricity. The CO_2 emissions from electricity generation (PE_y) are calculated as follows:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y} \tag{1}$$

Where:
$FC_{f,y}$:   = Is the total volume of natural gas or other fuel 'f' combusted in the project plant or other startup fuel (m3 or similar) in year(s) y

$COEF_{f,y}$:   = Is the CO_2 emission coefficient (tCO_2/m^3 or similar) in year(s) for each fuel and is obtained as:

$$COEF_{f,y} = \Sigma NCV_y * EF_{CO2f,f,y} * OXID_f \tag{1a}$$

Where:

$NCV_{f,y}$:   =   Is the net calorific value (energy content) per volume unit of natural gas in year y (GJ/m^3) as determined from the fuel supplier, wherever possible, otherwise from local or national data

$EF_{CO2,f,y}$:   =   Is the CO_2 emission factor per unit of energy of natural gas in year y (tCO_2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data

$OXID_f$:   =   Is the oxidation factor of natural gas

For start-up fuels, IPCC default calorific values and CO_2 emission factors are acceptable, if local or national estimates are unavailable.

Baseline emissions

Baseline emissions are calculated by multiplying the electricity generated in the project plant ($EG_{PJ,y}$) with a baseline CO_2 emission factor ($EF_{BL,CO2,y}$), as follows:

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y} \tag{2}$$

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 construction of an alternative power generation technology(s) could 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. In order to address this uncertainty in a conservative manner, project participants shall use for $EF_{BL,CO2,y}$ the lowest emission factor among the following three options:

For the first crediting period:

Option 1   The build margin, calculated according to "Tool to calculate emission factor for an electricity system"; and

Option 2   The combined margin, calculated according to "Tool to calculate emission factor for an electricity system", using a 50/50 OM/BM weight;

Option 3   The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above, and calculated as follows:

$$EF_{BL,CO2}(tco2/Mwh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh \tag{3}$$

Where:

$COEF_{BL}$:   =   The fuel emission coefficient (tCO2e/GJ), based on national average fuel data, if available, otherwise IPCC defaults can be used

η_{BL} :   =   The energy efficiency of the technology, as estimated in the baseline scenario analysis above

This determination will be made once at the validation stage based on an *ex ante* assessment, once again at the start of each subsequent crediting period (if applicable). If either option 1 (BM) or option 2 (CM) are selected, they will be estimated *ex post*, as described in "Tool to calculate emission factor for an electricity system".

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:[4]

- 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:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y}$$ **(4)**

Where:
$LE_{y:}$ =   Leakage emissions during the year y in tCO_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

Fugitive methane emissions

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:

$$LE_{CH4,y} = \left[FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4} \right] \cdot GWP_{CH4}$$ **(5)**

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[4] The EB 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.

Where:

$LE_{CH4,y}$:	=	Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_2e
FC_y :	=	Quantity of natural gas combusted in the project plant during the year y in m³
$NCV_{NG,y}$:	=	Average net calorific value of the natural gas combusted during the year y in GJ/m³
$EF_{NG,upstream,CH4}$:	=	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, in t CH_4 per GJ fuel supplied to final consumers
$EG_{PJ,y}$:	=	Electricity generation in the project plant during the year in MWh
$EF_{BL,upstream,CH4}$:	=	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH4 per MWh electricity generation in the project plant, as defined below
GWP_{CH4} :	=	Global warming potential of methane valid for the relevant commitment period

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL,upstream,CH4}$) should be calculated consistent with the baseline emission factor ($EF_{BL,CO2}$) used in equation (4) above, as follows:

Option 1:
Build
Margin:
$$EF_{BL,upstream,CH4} = \frac{\sum_{j} FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_{j} EG_{j}}$$

Option 2:
Combined
Margin:
$$EF_{BL,upstream,CH4} = 0.5 \cdot \frac{\sum_{j} FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_{j} EG_{j}} + 0.5 \cdot \frac{\sum_{i} FF_{i,k} \cdot EF_{k,upstream,CH4}}{\sum_{i} EG_{i}}$$

Option 3:
Baseline
technology:
$$EF_{BL,upstream,CH4} = \frac{EF_{k,upstream,CH4}}{\eta_{BL}} * 3.6 GJ / MWh$$

Where:

$EF_{BL,upstream,CH:4}$	=	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant
j :	=	Plants included in the build margin
$FF_{j,k}$:	=	Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin
$EF_{k,upstream,CH4}$:	=	Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type) in t CH_4 per MJ fuel produced
EG_{j} :	=	Electricity generation in the plant j included in the build margin in MWh/a
i:	=	Plants included in the operating margin
$FF_{i,k}$:	=	Quantity of fuel type k (a coal or oil type) combusted in power plant i included in the operating margin
EG_{i}:	=	Electricity generation in the plant i included in the operating margin in MWh/a
η_{BL} :	=	Energy efficiency of the most likely baseline technology

If $EF_{BL,upstream,CH4}$ 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 emission factor for an electricity system".

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.

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.

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.

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.

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[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.

Table 2: Default emission factors for fugitive CH₄ 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.

CO₂ 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:

$$LE_{LNG,CO2,y} = FC_y \cdot EF_{CO2,upstream,LNG}$$

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

FC_y : = Quantity of natural gas combusted in the project plant during the year y in m³

$EF_{CO2,upstream,LNG:}$ = 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.[6]

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

Emission Reductions

To calculate the emission reductions the project participant shall apply the following equation:

$$ERy = BEy – PEy – LEy \qquad\qquad (6)$$

Where:
ERy: =   Emissions reductions in year y (t CO_2e)
BEy: =   Emissions in the baseline scenario in year y (t CO_2e)
PEy: =   Emissions in the project scenario in year y (t CO_2e)
LEy: =   Leakage in year y (t CO_2e)

Changes required for methodology implementation in 2nd and 3rd crediting periods (if relevant/ optional)

See changes described above under baseline emissions.

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[6] 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)".

Approved monitoring methodology AM0029

**Grid Connected Electricity Generation Plants using Non-Renewable and
Less GHG Intensive Fuel**

Sources

This monitoring methodology is based on the proposals NM0080-rev "Baseline methodology for grid connected generation plants using non-renewable and less GHG intensive fuel" and NM0153 "Baseline methodology for grid connected electricity generation plants using Natural Gas (NG)/Liquiefied Natural Gas (LNG) as fuels" submitted by Torrent Power Generation Limited (TPGL), assisted by PricewaterhouseCoopers (P), and Reliance Energy Limited (REL) respectively.

For more information regarding the proposal and its consideration by the Executive Board please refer to <http://cdm.unfccc.int/methodologies/approved>.

This methodology also uses the build margin (BM) approach as specified in "Tool to calculate emission factor for an electricity system", with annual *ex post* determination of baseline emission factor, and the "Tool for the demonstration and assessment of additionality".

Applicability

The methodology is applicable under the same conditions as the associated baseline methodology.

This baseline methodology shall be used in conjunction with the approved baseline methodology AM0029.

Brief Description of Methodology

The primary parameters to be monitored during the crediting period of the project activity are listed below. Other parameters will be calculated using the primary parameters.

For project emissions:

1. Annual fuel(s) consumption in project activity;
2. Net Calorific Value(s) of the fuel used in the project activity;
3. Fuel emission factors for fuel used in the project activity.

Baseline emissions will be monitored per "Tool to calculate emission factor for an electricity system"**, if and as applicable.**

Project emissions parameters

Data to be collected or used in order to monitor emissions from the project activity, and how this data will be archived:

ID number	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
$FC_{f,y}$	Annual quantity of fuel "f" consumed in project activity	Fuel flow meter reading at project boundary	m3	m	Daily	100%	Electronic/ paper	The total fuel consumption will be monitored both at supplier and project end for cross-verification
$NCV_{f,y}$	Net Calorific Value of fuel f	Fuel Supplier, Local Authority, Country-specific, IPCC	GJ/m3	e	Fortnightly	100%	Electronic	Use supplier-provided data, local data, country-specific values, that order of preference. IPCC values can be used for startup fuel
$OXID_f$	Oxidation factor	IPCC	--	e	Annual	100%	Electronic	Use IPCC current default
$EF_{CO2,f,y}$	Emission factor for fuel 'f'	Local/ Regional/ Global (IPCC)	tCO_2/GJ	e	Annual	100%	Electronic	Use supplier-provided data, local data, country-specific values, that order of preference. IPCC values can be used for startup fuel
$COEF_y$	CO_2 emission coefficient	Calculated Under project activity	tCO_2/m^3	c	Annual	100%	Electronic	

ID number	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/paper)	Comment
PEy	Project emission due to combustion of fuel	Calculated under project activity	tCO_2	c	Annual	100%	Electronic	

Baseline emission parameters

See "Tool to calculate emission factor for an electricity systemfor relevant baseline emission parameters".

Quality Control (QC) and Quality Assurance (QA) Procedures

All measurements should use calibrated measurement equipment that is maintained regularly and checked for its functioning. QA/QC procedures for the parameters to be monitored are illustrated in the following table:

Data	Uncertainty Level of Data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary
1. FCy	Low	Natural gas supply metering to the project will be subject to regular (in accordance with stipulation of the meter supplier) maintenance and testing to ensure accuracy. The readings will be double checked by the gas supply company
2. NCVy	Low	No additional QA/QC procedures may need to be planned
3. OXID	Low	No additional QA/QC procedures may need to be planned
4. EFCO2y	Low	No additional QA/QC procedures may need to be planned
5. COEFy	Low	No additional QA/QC procedures may need to be planned

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History of the document

Version	Date	Nature of revision(s)
03	EB 39, Annex 3 16 May 2008	• Flexibility to choose the most appropriate financial indicator to be used in the analysis for the identification of the baseline scenario; • To clarify that the 1% threshold to characterize small amounts of other start-up or auxiliary fuels refers to energy basis; • To emphasize that the range of the sensitivity analysis should cover, in a realistic way, the economic dynamics of all key parameters that are related to the analysis and that could change over the crediting period.
02	EB 35, Para 24, 19 October 2007	Revision to incorporate the use of the "Tool to calculate emission factor for an electricity system"
01	EB 24, Annex 11, 12 May 2006	Initial adoption