Approved consolidated baseline and monitoring methodology ACM0013

Construction and operation of new grid connected fossil fuel fired power plants using a less GHG intensive technology

I. SOURCE AND APPLICABILITY

Sources

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

- NM0215 "Baseline and Monitoring Methodology for Grid Connected High-efficiency Coal-fired Electricity Generation in Countries Where Different Power Expansion Plans are Formulated for Broadly Different Power Technologies and Where These Plans are Restrictive" prepared by Huaneng Power International, Inc., Global Climate Change Institute of the Tsinghua University and CDM Office of CWEME, China;
- NM0217 "Grid-connected supercritical coal-fired power generation" submitted by NTPC Ltd, India, whose baseline study and project design document were prepared by Perspectives Climate Change GmbH, Hamburg, Germany.

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

- "Tool to calculate the emission factor for an electricity system";
- "Tool for the demonstration and assessment of additionality";
- "Assessment of the validity of the current/original baseline and update of the baseline at the renewal of the crediting period".

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

and

"The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 per cent of their category".

Definitions

For the purpose of this methodology the following definitions apply:

Power plant. A facility for the generation of electric power. In case where several power units have been installed at one site, each unit should be considered as a power plant. For example, two 600 MW coal-fired power units installed at one site should be considered as two power plants.

Cogeneration plant. A plant that: (i) simultaneously generates heat and power through combustion of fuels; and (ii) provides useful thermal energy to end-users which use the heat for other purposes than power generation (e.g. industrial users, district heating, etc.).

Fossil fuel category refers to the following three categories of fossil fuels in Table 1.1 in Volume 2_Energy, Chapter 1, of the 2006 IPCC Guidelines: (i) liquid fuels (Crude oil and petroleum products); (ii) solid fuels (Coal and coal products); and (iii) gas (Natural Gas).

Fossil fuel type refers to the fuel types as defined in Table 1.1 in Volume 2: Energy, Chapter 1, of the 2006 IPCC Guidelines.

Power generation technology refers to one of the following technologies, ranked by their efficiency, from the lowest to the highest efficiency, for each fossil fuel category:

- Solid fuels: subcritical technology, supercritical technology, and ultra-supercritical technology;
- Gaseous fuels: single cycle technology and combined cycle technology;
- Liquid fuels: single cycle technology and combined cycle technology.

The specifications of each technology are given in the appendix. Additions and revisions to the definition of the power plant technology may be proposed through the “Procedure for the submission and consideration of requests for revision of AMs and tools for large scale CDM project activities”.

Applicability

The methodology is applicable under the following conditions:

- The project activity is the construction and operation of a new fossil fuel fired grid-connected power plant that uses a more efficient power generation technology than what would otherwise be used with the given fossil fuel category;
- A single fossil fuel category should be used as main fuel in the project power plant. In addition to this main fossil fuel category, small amounts of other fossil fuel categories can be used for start-up or auxiliary purposes,[1] but they shall not comprise more than 3% of the total fuels used annually on an energy basis;
- The project activity does not include the construction or operation of a co-generation power plant;
- The information, as required under this methodology, on power plants that are planned or under construction, and the data, as required under this methodology, on fuel consumption and electricity generation of recently constructed power plants are available;
- The identified baseline fuel category is used as the main fuel category in more than 50% of the total rated capacity of power plants which were commissioned for commercial operation in the most recent five calendar/fiscal years prior to the publication of the CDM-PDD for global stakeholder consultation, within the electric grid[2] to which the project plant will be connected;

[1] The DOE should verify that start-up or auxiliary fuels are only used during: the start-up periods of the power plant, or short periods of interruption in the supply of the main fuel due to technical or operational problems. This is to ensure that it is not a common practice, during the normal operation of the power plant, to fire or co-fire these categories of fuel as a multi-fuel power plant.

[2] The grid boundary is defined as per the latest version of the “Tool to calculate the emission factor for an electricity system” approved by the Board.

- At least five new power plants can be identified as similar to the project plant in Step 1 of the baseline identification procedure;
- The most likely technology, as determined in the section "Identification of the baseline scenario" below, fulfills the conditions presented in Step 3 of that section.

This methodology is only applicable to new power plants. For project activities involving a retrofit of existing power plants, project participants are encouraged to submit new methodologies or submit a request for revision to existing methodologies, as appropriate. For project activities involving a switch to a less GHG intensive fossil fuel in existing power plants, project participants may consider using the approved methodology ACM0011 "Consolidated baseline methodology for fuel switching from coal and/or petroleum fuels to natural gas in existing power plants for electricity generation". For project activities involving the construction and operation of a new power plant with less GHG intensive fossil fuel, project participants may use other approved methodologies (e.g. AM0029 "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas").

II. BASELINE METHODOLOGY PROCEDURE

Identification of the baseline scenario

The baseline scenario is identified based on an assessment of which new power generation technologies use the same fossil fuel category as the project activity and are currently being implemented in the geographical area (as defined in Step 1 below) of the project activity.

Project participants shall use the following steps to identify the most likely technology that would be applied in the baseline scenario (i.e. the baseline technology):

Step 1: Identify all new power plants similar to the project activity

Identify all power plants (excluding power plants registered as CDM project activities, and power plants requesting registration as CDM project activities or under validation) which fulfill all of the following conditions when the CDM-PDD is published for global stakeholder consultation:

- The plant uses the same fossil fuel category as the project activity. The plant may use small amounts of fuels within another fossil fuel category than the main fuel category for start-up or auxiliary purposes, but these other fuels shall not comprise more than 3% of the total fuels used annually by the power plant on an energy basis;
- The plant is not a cogeneration plant;
- The plant has been issued with a government permit;[3]
- The government permit was issued fewer than five years;
- The plant has not yet started commercial operation;
- The plant has a comparable size to the project activity, defined as the range from 50% to 200% of the planned capacity of the project plant; and
- The plant is planned to be operated in the same load category, i.e. at peak load (defined as a load factor of less than 3,000 hours per year) or base load (defined as a load factor of more than 3,000 hours per year), as the project activity.

[3] The government permit refers to the permit or, where applicable, the entire set of permits required to begin the construction of a power plant, e.g. Consent to Establish, Permit to Construct, and/or approval from a central planning agency.

The plants fulfilling the conditions above shall be identified first within the boundary of the grid to which the project plant will be connected. Use these plants in the subsequent steps if the number of identified plants is equal to or larger than five. Otherwise, the geographical area should be extended to the country. If the number of the identified plants is still less than five, the geographical area should be extended by including all neighboring non-Annex I countries. If the number remains to be less than five, all non-Annex I countries in the continent should be considered.

For each identified power plant, document in the CDM-PDD in a table the following information: name of the unit, operator of the unit, location of the unit (including state/province and county/city), the power generation technology used, the planned capacity of the unit, and the year when the government permit was issued. If this information is not available or if less than five power plants could be identified in all non-Annex I countries in the continent, then the methodology is not applicable.

Step 2: Determine the market share of each technology

Based on the power generation technology and the planned capacity of each plant identified in Step 1 above, calculate the market share of each technology, by dividing the total planned capacity of each technology by the total planned capacity of all identified plants.

Step 3: Identify the baseline technology

Sort the market share of the technologies (e.g. subcritical technology, supercritical technology, and ultra-supercritical technology), as ranked in the definition section of this methodology.

Add up the market shares of each technology one by one from the end of the least efficient technology until the subtotal of market shares reaches 80% in terms of planned generation capacity. The technology at the 80th percentile within this subset shall be selected as the baseline technology.

The methodology is applicable only if all of the following conditions are fulfilled:

(a) The baseline technology, as identified by applying the procedure outlined above, is different from and less efficient than the project technology;

(b) The use of the baseline technology at the project activity site would be in compliance with all mandatory applicable legal and regulatory requirements;

(c) For both the baseline technology and the project technology, the project participants have conducted one combined or two separate feasibility study(ies),[4] which shall have the same level of detail in the analysis for both technologies and shall contain at least the following information:

- A power plant design study which specifies the type of equipment and key design parameters of the plant, including, inter alia, the type of the pre-heating system, the boiler, the turbine, the generator, the condenser, the air pollution control equipment, etc., as well as all information on the key operating parameters, such as steam temperatures, pressures, re-heating temperatures and pressures, condensing temperatures and pressures, excess air ratio, etc.;
- The design and operation efficiency of the technology;
- An estimate of all costs based on quotes received from technology suppliers, including investment costs and operating and maintenance costs; and
- A specification of the fuel type(s) used.

[4] Preliminary feasibility studies, or studies conducted for the FEL-2 stage or other equivalent project planning stage, are permitted if they contain the information as required by the methodology for the feasibility studies.

The feasibility study(ies) shall be the one(s) that are used by the project proponent to make the investment decision and shall be conducted based on the specific characteristics of the site where the project activity is implemented, taking into account ambient conditions (e.g. air temperature and humidity in the case of air cooling), fuel availability, and any other site-specific characteristics.

The site characteristics and the fossil fuel type and its origin shall be the same for the baseline technology and the project technology in the feasibility studies or an appropriate justification for the differences shall be provided in the CDM-PDD.

Additionality

Project participants shall use the following steps to demonstrate the additionality of the proposed project activity:

Step 1: Identification of alternatives to the project activity

The alternative scenarios shall be limited to two scenarios:

- The proposed project activity undertaken without being registered as a CDM project activity; and
- Electricity is supplied by a new power plant applying the baseline technology, as determined in the section "Identification of the baseline scenario" above.

Step 2: Investment analysis

This step should be implemented following Step 2 of the latest version of the "Tool for the demonstration and assessment of additionality", except where methodology-specific requirements are set out further below. In validating the application of this step, designated operation entities (DOEs) shall carefully assess and verify the reliability and creditability of all data, rationales, assumptions, justifications and documentation provided by the project participants to support the demonstration of additionality. The elements checked during this assessment and the conclusions shall be documented transparently in the validation report.

In applying this step, the investment comparison analysis (Option II) shall be used and the levelized cost of electricity production shall be used as the financial indicator. The levelized cost of electricity production in $/kWh shall, where applicable:

- Include all relevant costs (including the investment cost, fuel costs and operation and maintenance costs);
- Include subsidies/fiscal incentives/tax benefits,[5] ODA, etc. Non-market cost and benefits shall also be included in the case of public investors if this is standard practice for the selection of public investments in the host country. If the feed-in tariff of the project plant is higher than the feed-in tariff which would apply to the baseline technology implemented at the project site, then the difference between the feed-in tariffs shall be considered as a subsidy for the project plant;
- Exclude income taxes, revenues from sales of electricity generation, and other revenues not related to electricity sales (e.g. payments for capacity or reserve).

The fuel type used for the investment analysis shall be the same in the two scenarios identified in Step 1. The load factor used in the calculation for the proposed project activity shall be equal to or higher than the load factor used for the baseline scenario. Other assumptions and input data for the

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

investment analysis shall not differ between the scenario of the project activity and the baseline scenario, unless differences can be well substantiated.

In applying the sensitivity analysis, critical assumptions, such as, inter alia, fuel prices and the load factor shall be varied.

The proposed project activity is deemed additional if all the following conditions are fulfilled:

- The investment analysis concludes that the levelized costs of electricity production are lower for the alternative scenario with the baseline technology than for the proposed project activity;
- The sensitivity analysis consistently supports (for a realistic range of assumptions) the conclusion that the levelized costs of electricity production are lower for the alternative scenario with the baseline technology than the proposed project activity.

Project boundary

The spatial extent of the project boundary includes the power plant at the project site and all power plants considered for the calculation of the baseline CO_2 emission factor ($EF_{BL,CO2,y}$).

In the calculation of project emissions, only CO_2 emissions from fossil fuel combustion in 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 in the project plant	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification
		N_2O	No	Excluded for simplification

Project emissions

The project activity is the on-site combustion of fossil fuels in the project plant to generate electricity. The CO_2 emissions from electricity generation in the project plant (PE_y) should be calculated as follows:

$$PE_y = \left[\sum_i FF_{i,y} \times NCV_{i,y} \right] \times EF_{FF,CO2} \quad (1)$$

Where:

PE_y	=	Project emissions in year *y* (t CO_2/yr)
$FF_{i,y}$	=	Quantity of fuel type *i* combusted in the project plant in year *y* (Mass or volume unit per year)
$NCV_{i,y}$	=	Weighted average net calorific value of fuel type *i* in year *y* (GJ per mass or volume unit)
i	=	Fossil fuel types used in the project plant in year *y*
$EF_{FF,CO2}$	=	CO_2 emission factor of the fossil fuel type used in the project and the baseline (t CO_2/GJ)

Baseline emissions

Baseline emissions are calculated by multiplying the electricity generated in the project plant from using fossil fuel types within the main fossil fuel category ($EG_{PJ,main\_FF,y}$)[6] with a baseline CO_2 emission factor ($EF_{BL,CO2}$), as follows:

$$BE_y = EG_{PJ,main\_FF,y} \times EF_{BL,CO2} \tag{2}$$

and

$$EG_{PJ,main\_FF,y} = EG_{PJ,y} \times \left[\frac{\sum_p \left(FC_{p,y} \times NCV_{p,y}\right)}{\sum_p \left(FC_{p,y} \times NCV_{p,y}\right) + \sum_q \left(FC_{q,y} \times NCV_{q,y}\right)} \right] \tag{3}$$

Where:

BE_y	=	Baseline emissions in year *y* (tCO_2/yr)
$EG_{PJ,main\_FF,y}$	=	Net quantity of electricity generated in the project plant from using fossil fuel types within the main fossil fuel category in year *y* (MWh/yr)
$EG_{PJ,y}$	=	Total net quantity of electricity generated in the project plant in year *y* (MWh/yr)
$EF_{BL,CO2}$	=	Baseline emission factor (t CO_2/MWh)
$FC_{p,y}$	=	Quantity of fossil fuel type *p* consumed by the project plant in year *y* (Mass or volume unit/yr)
$NCV_{p,y}$	=	Average net calorific value of the fossil fuel type *p* consumed by the project plant in year *y* (GJ/Mass or volume unit)
$FC_{q,y}$	=	Quantity of fossil fuel type *q* consumed by the project plant in year *y* (Mass or volume unit/yr)
$NCV_{q,y}$	=	Average net calorific value of the fossil fuel type *q* consumed by the project plant in year *y* (GJ/Mass or volume unit)
P	=	Fossil fuel types that are used in the project plant and that belong to the main fossil fuel category
q	=	Fossil fuel types that are used in the project plant for auxiliary and start-up purposes

$EF_{BL,CO2}$ will be determined using the lower value between: (i) the emission factor of the technology and fuel type that has been identified as the most likely baseline scenario; and (ii) a benchmark emission factor determined based on the performance of the top 15% power plants that use the same

[6] This methodology allows to claim emission reductions from using fossil fuels more efficiently for power generation, but does not account for any emission reductions from using less carbon intensive fuels. Given that the CO_2 emission factor and amount of any start-up/auxiliary fuels may differ between the project and the baseline, the crediting of emission reductions is limited to the electricity generated from the main fossil fuel only.

fuel category as the project plant and any technology available in the geographical area as defined in Step 1.3 below.

Consequently, project participants shall use for $EF_{BL,CO2}$ the lower value from the following two approaches:

Approach 1: The emission factor of the technology identified as the most likely baseline scenario under the "Identification of the baseline scenario" section above, and calculated as follows:

$$EF_{BL,CO2} = 3.6 \times \frac{EF_{FF,CO2}}{\eta_{BL}} \quad \textbf{(4)}$$

Where:

$EF_{BL,CO2}$	=	Baseline emission factor (t CO_2/MWh)
$EF_{FF,CO2}$	=	CO_2 emission factor of the fossil fuel type used in the project and the baseline (t CO_2/GJ)
η_{BL}	=	Energy efficiency of the power generation technology that has been identified as the most likely baseline scenario
3.6	=	Unit conversion factor from GJ to MWh

Approach 2: The average emissions intensity of all power plants *j*, corresponding to the power plants whose performance is among the top 15 % of their category, using data from the reference year *v*, and taking into account the technological development that would likely have occurred in the time between the investment decision on the power plants *j* and the investment decision on the project activity, as follows:

$$EF_{BL,CO2} = \frac{EF_{FF,CO2}}{\eta_{avg,j} + \Delta\eta} \times 3.6 \quad \textbf{(5)}$$

with

$$\eta_{avg,j} = 3.6 \times \frac{\sum_{j} EG_{j,v}}{\sum_{j} \left(FC_{j,v} \times NCV_{j,v} \right)} \quad \textbf{(6)}$$

$EF_{BL,CO2}$	=	Baseline emission factor (t CO_2/MWh)
$\eta_{avg,j}$	=	Weighted average efficiency of power plants *j* (dimensionless)
$\Delta\eta$	=	Efficiency improvement for newly constructed power plants that would likely have occurred due to technical development in the time between the investment decisions made for the power plants *j* and the investment decision made for the proposed project activity (dimensionless)
$FC_{j,v}$	=	Amount of fuel consumed by power plant *j* in the reference year *v* (Mass or volume unit per year)
$NCV_{j,v}$	=	Average net calorific value of the fossil fuel type consumed by power plant *j* in the reference year *v* (GJ/Mass or volume unit)
$EF_{FF,CO2}$	=	CO_2 emission factor used in the project and the baseline (t CO_2/GJ)

$EG_{j,v}$	=	Net electricity generated and delivered to the grid by power plant *j* in the reference year *v* (MWh/yr)
j	=	The top 15% performing power plants as identified below, among all power plants in the geographical area as identified in Step 1.3

In the following steps, the parameters $\eta_{avg,j}$ and $\Delta\eta$ are determined. In applying these steps, all underlying data, the data sources and all calculations shall be transparently documented in the CDM-PDD, in a manner that the reader can re-produce the calculations.

Step 1:-Determination of $\eta_{avg,j}$

Steps 1.1 to 1.3 may need to be applied in an iterative manner until the set of the similar plants is finally identified.

Step 1.1: Definition of similar plants to the project activity

The cohort of similar power plants used to calculate $\eta_{avg,j}$ should consist of all power plants (including all power plants registered as CDM project activities, requesting registration as CDM project activities, or under validation) that fulfill all of the following conditions:

- That use the same fossil fuel category (as the main fuel) as the project activity. This should include power plants which use small amounts of fuels within another fossil fuel category than the main fuel for start-up or auxiliary purposes, but these other fuels shall not comprise more than 3% of the total fuels used annually by the power plant on an energy basis;
- That started commercial operation within the four year period preceding the reference year *v* , which is initially set as the calendar/fiscal year prior to the date of publication of the CDM-PDD for global stakeholder consultation;
- That are not co-generation plants;
- That have a comparable size to the project activity, defined as the range from 50% to 200% of the rated capacity of the project plant;
- That are operated in the same load category, i.e. at peak load (defined as a load factor of less than 3,000 hours per year) or base load (defined as a load factor of more than 3,000 hours per year), as the project activity; and
- That have supplied electricity to the grid in the reference year *v*.

Step 1.2: Determination of the reference year v

If the necessary data for all similar power plants within the electric grid[7] to which the project plant will be connected are not available for the calendar/fiscal year prior to the date of publication of the CDM-PDD for global stakeholder consultation, then the previous calendar/fiscal year should be selected as the reference year *v* and Step 1.1 shall be applied for this year. If the necessary data for that year is also not available, then this step can be repeated for the next previous year, until either the necessary data is available or until the reference year *v* is the calendar/fiscal year that starts between three and four years prior to the date of publication of the CDM-PDD for global stakeholder consultation. If the necessary data is also not available for this calendar/fiscal year, then the methodology is not applicable.

Step 1.3: Identification of the cohort of power plants and the geographical area

Identify all power plants *n* that are to be included in the cohort of plants used to determine $\eta_{avg,j}$ by applying the criteria in Step 1.1 and using the reference year *v* as determined in Step 1.2. Determine

the total number *N* of all identified similar power plants that are connected to the grid[7] to which the project plant will be connected.

If the number of similar plants within the electric grid to which the project plant will be connected is less than 10, then the geographical area should be extended to the country and Steps 1.1 and 1.2 should be iterated for the country. If the number of similar plants is still less than 10, the geographical area should be extended by including all neighboring non-Annex I countries and Steps 1.1 and 1.2 should be iterated accordingly. If the number remains to be less than 10, all non-Annex I countries in the continent should be considered and Steps 1.1 and 1.2 should be reiterated accordingly.

If the necessary data on the similar power plants in the relevant geographical area are not available, or if there are less than 10 similar power plants in all non-Annex I countries in the continent, then the methodology is not applicable.

Step 1.4: Determination of the plant efficiencies

Calculate the operational efficiency of each power plant *n* identified in the previous step. For each plant, the one-year data from the reference year *v* shall be used, excluding the period when testing of the plant was conducted. The operational efficiency of each power plant *n* in the cohort is calculated as follows:

$$\eta_{n,v} = 3.6 \times \frac{EG_{n,v}}{FC_{n,v} \times NCV_{n,v}} \qquad \textbf{(7)}$$

Where:

$\eta_{n,v}$	=	Operational efficiency of the power plant *n* in the reference year *v*
$EG_{n,v}$	=	Net electricity generated and delivered to the grid by the power plant *n* in the reference year *v* (MWh/yr)
$FC_{n,v}$	=	Quantity of fuel consumed in the power plant *n* in the reference year *v* (Mass or volume unit/yr)
$NCV_{n,v}$	=	Average net calorific value of the fuel type fired in power plant *n* in the reference year *v* (GJ/mass or volume unit)
3.6	=	Unit conversion factor from GJ to MWh
v	=	Reference year *v*
n	=	All power plants identified in Step 1.3

Step 1.5: Identification of the top 15% performer plants j

Sort the cohort of *N* plants in a decreasing order of the operational efficiency. Identify the top performer plants *j* as the plants with the 1^{st} to j^{th} highest operational efficiency, where the *j* (the total number of plants *j*) is calculated as the product of *N* (the total number of plants *n* identified in Step 1.3) and 15%, rounded down if it is decimal.[8] If the generation of all identified plants *j* (the top performers) is less than 15% of the total generation of all plants *n* (the whole cohort), then the number of plants *j* included in the top performer group should be enlarged until the group represents at least 15% of total generation of all plants *n*.

7 The grid boundary is defined as per the latest version of the "Tool to calculate the emission factor for an electricity system" approved by the Board.

8 This is conservative as this limits the number of the top 15% performer plants, which will always lead to exclusion of the least efficient plant among them.

Step 2: Determination of $\Delta\eta$

If the time difference between yr_{proj} (the envisaged start date of commercial operation of the proposed project activity) and yr_j (the average start date of commercial operation of power plants *j)* is determined to be less than 1 year, $\Delta\eta$ is set at zero; otherwise, the project participants may choose between the following two options to determine $\Delta\eta$*:*

Option A: Determine $\Delta\eta$ based on historical data

Calculate $\Delta\eta$ based on the historical technical development observed in the applicable geographical area as defined in Step 1.3. Determine $\Delta\eta$ based on the improvement in the efficiency of newly constructed power plants observed over a period of 10 years in the applicable geographical area by applying a trend analysis. The last year of the trend analysis shall be the calendar/fiscal year prior to the reference year *v*. The first year of the trend analysis shall be the calendar/fiscal year 10 years prior to the reference year *v*.

Apply and document in the CDM-PDD the following steps:

- Step 2.A.1: identify all power plants *m* within the applicable geographical area, as determined in Step 1.3 above:
    - That use the same fossil fuel category (as the main fuel) as the project activity. This should include power plants which use small amounts of fuels within another fossil fuel category than the main fuel for start-up or auxiliary purposes, but these other fuels shall not comprise more than 3% of the total fuels used annually by the power plant on an energy basis;
    - That are not co-generation plants;
    - That started commercial operation within the ten year period preceding the reference year *v* (i.e. that started commercial operation within the years v-10 to v-1);
    - That have a comparable size to the project activity, defined as the range from 50% to 200% of the rated capacity of the project plant;
    - That are operated in the same load category, i.e. at peak load (defined as a load factor of less than 3,000 hours per year) or base load (defined as a load factor of more than 3,000 hours per year), as the project activity;
    - That have supplied electricity to the grid in the reference year *v*.
- Step 2.A.2: determine for each plant *m* the operational efficiency $\eta_{m,v}$ in the year *v*, by applying the equation in Step 1.4 above for all power plants *m* and for the year in which the plant started commercial operation;
- Step 2.A.3: plot the efficiency of all power plants *m* over the date in which the power plants started commercial operation and apply a trend analysis and determine the efficiency as a function of the year when commercial operation is started. The function f(yr) is a best fit linear or exponential curve using the method of least squares;
- Step 2.A.4: if the trend is determined to be statistically insignificant with a student test, i.e. rejecting at 5% significance level the hypothesis that the efficiency of the newly constructed power plant during the last 10 years does not depend on the start date of commercial operation of the plants, then a value of 0.2% is assumed for the annual efficiency improvement and $\Delta\eta$ is determined as follows:[9]

[9] According to the 2005 IEA report, "Reducing Greenhouse Gas Emissions. The Potential of Coal", "under ideal conditions, modern coal-fired power plants are capable of achieving efficiency levels of more than 40% on a higher heating value basis. This is about a 30% improvement on plants built in the 1950s and 1960s".

$$\Delta\eta = 0.2\% \times (yr_{proj} - yr_j) \quad \textbf{(8)}$$

If the trend analysis is statistically significant with a student test and determines $\Delta\eta$ to be less than zero when applying equation (9) below, then $\Delta\eta$ is conservatively assumed to be zero. Otherwise, $\Delta\eta$ is calculated as follows:

$$\Delta\eta = f(yr_{proj}) - f(yr_j) \quad \textbf{(9)}$$

Where:

$\Delta\eta$	=	Efficiency improvement for newly constructed power plants that would likely have occurred due to technical development in the time between the investment decisions made for the power plants *j* and the investment decision made for the proposed project activity (dimensionless)
yr_{proj}	=	Envisaged start date of commercial operation of the proposed project activity
yr_j	=	Average start date of commercial operation of power plants *j*

Option B: Assume a conservative default value of 0.3% for annual efficiency improvement and $\Delta\eta$ is calculated as follows:[10]

$$\Delta\eta = 0.3\% \times (yr_{proj} - yr_j) \quad \textbf{(10)}$$

Where:

$\Delta\eta$	=	Efficiency improvement for newly constructed power plants that would likely have occurred due to technical development in the time between the investment decisions made for the power plants *j* and the investment decision made for the proposed project activity (dimensionless)
yr_{proj}	=	Envisaged start date of commercial operation of the proposed project activity
yr_j	=	Average start date of commercial operation of power plants *j*

All the underlying data, data sources, calculations and steps to estimate $\eta_{avg,j}$ and $\Delta\eta$ shall be documented transparently in the CDM-PDD, including, inter alia, a list of the plants identified in Steps 1.3 and 1.5 for $\eta_{avg,j}$ and a list of the plants identified in Step 2.A.1 for $\Delta\eta$, as well as relevant data on the fuel consumption and electricity generation of all identified power plants. The DOE shall check the fuel consumption and electricity generation against records on purchased fuel and sold electricity for all identified power plants; if such information is not available, the DOE may check against government publications provided that the data are collected and verified by a governmental organization and they are based on the actual fuel consumption and electricity generation of the plants and not derived from other data (e.g. regulations).

Leakage

No leakage emissions are to be considered.

Therefore, the increase in efficiency during 50 years since 1960 was about 10 percentage points which corresponds to an average annual efficiency improvement of about 0.2 percentage point.

[10] This is the upper end of the values assumed for the average annual efficiency improvement in the information note prepared by the Methodologies Panel at its 53rd meeting.

Emission reductions

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

$$ER_y = BE_y - PE_y \quad \textbf{(11)}$$

Where:

ER_y	=	Emission reductions in year y (t CO_2/yr)
BE_y	=	Baseline emissions in year y (t CO_2/yr)
PE_y	=	Project emissions in year y (t CO_2/yr)

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

The required changes should be assessed using the tool for "Assessment of the validity of the current/original baseline and update of the baseline at the renewal of the crediting period".

The baseline emission factor ($EF_{BL,CO2}$) shall be updated, applying both Approaches 1 and 2 and choosing for the subsequent crediting period again the lower value among the two approaches. For Approach 1, the most likely power plant technology identified in the application of the procedure to select the baseline scenario should be used. For Approach 2, at the first renewal of the renewal crediting period, the baseline emission factor should be recalculated using a new reference year *v*. The new reference year *v* shall be the calendar/fiscal year which is two years after the actual start of commercial operation of the project activity. This provision aims to reduce the data vintage (between the start of commercial operation of the proposed project activity and the average start time of commercial operation of power plants *j*) to less than one year for second and third crediting periods.

Data and parameters not monitored

Data / Parameter:	η_{BL}
Data unit:	-
Description:	Energy efficiency of the power generation technology that has been identified as the most likely baseline scenario
Source of data:	This parameter is determined as part of the baseline scenario selection procedure
Measurement procedures (if any):	-
Any comment:	As a conservative approach, the efficiency should be determined as the efficiency at optimum load, as provided in the feasibility study(ies) conducted for the identified baseline power generation technology and for the project site. The efficiency shall be derived on a net basis, taking into account auxiliary equipment. The efficiency shall not be derived from any historical operational data from existing power plants. In addition, the adopted value shall not be lower than the minimum efficiency (if available) specified for the respective baseline technology in the appendix

Data / Parameter:	$FC_{j,v}$, $FC_{m,v}$, and $FC_{n,v}$
Data unit:	Mass or volume unit/yr
Description:	Amount of fuel consumed by power plant *j, m* or *n* in the reference year *v,* where: • *j* are the top 15% performer plants among all power plants in a defined geographical area as defined in Step 1.3 under "Baseline emissions" section; • *m* are all power plants in the defined geographical as defined in Step 2.A.1 to determine Δη under "Baseline emissions" section; • *n* are all power plants in the defined geographical area as defined in Step 1.3 under "Baseline emissions" section
Source of data:	Measurements of the fuel consumption in each power plant *j* or *n*, e.g. provided in statistics from central/regional regulatory authorities
Measurement procedures (if any):	-
Any comment:	The DOE should verify that the data on fuel consumption is based on first-hand measurements of the actual quantity of fuel consumed by each power plant, and is not based on second-hand calculations or estimations

Data / Parameter:	$NCV_{j,v}$, $NCV_{m,v}$, and $NCV_{n,v}$
Data unit:	GJ/Mass or volume unit
Description:	Average net calorific value of the fossil fuel type consumed by power plant *j, m* or *n* in the reference year *v,* where: • *j* are the top 15% performer plants among all power plants in a defined geographical area as defined in Step 1.3 under the "Baseline emissions" section; • *m* are all power plants in the defined geographical as defined in Step 2 in Option A to determine Δη under the "Baseline emissions" section; • *n* are all power plants in the defined geographical area as defined in Step 1.3 under the "Baseline emissions" section
Source of data:	Use plant-specific data if available (e.g. from national energy balances if the fuel consumption of the plant is provided on an energy basis). Otherwise use well-documented and reliable regional or national average values. If such data are not available, IPCC default values may be used
Measurement procedures (if any):	-
Any comment:	-

Data / Parameter:	$EF_{FF,CO2}$
Data unit:	tCO_2/GJ
Description:	CO_2 emission factor of the fossil fuel type used in the project and the baseline (tCO_2/GJ)
Source of data:	IPCC default values of the fuel type used in the project plant 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. In the case that several fuel types may be used in the project plant according to the technology provider's designs, use the fuel type with the lowest IPCC default value at the lower limit of the uncertainty
Measurement procedures (if any):	-
Any comment:	-

Data / Parameter:	$EG_{j,v}$, $EG_{m,v}$, and $EG_{n,v}$
Data unit:	MWh/yr
Description:	Net electricity generated and delivered to the grid by power plant *j*, *m* or *n* in the reference year *v,* where: • *j* are the top 15% performer plants among all power plants in a defined geographical area as defined in Step 1.3-under the “Baseline emissions” section; • *m* are all power plants in the defined geographical as defined in Step 2 in Option A to determine Δη under the “Baseline emissions” section; • *n* are all power plants in the defined geographical area as defined in Step 1.3 under the “Baseline emissions” section
Source of data:	Electricity generation statistics, e.g. from central-/regional regulatory authorities
Measurement procedures (if any):	-
Any comment:	-

Data / Parameter:	yr_{proj}
Data unit:	-
Description:	The envisaged start date of commercial operation of the proposed project activity
Source of data:	Determined as per Step 2 of the “Baseline emissions” section above. Documented evidence on the envisaged start of commercial operation of the proposed project activity shall be provided
Measurement procedures (if any):	-
Any comment:	

Data / Parameter:	yr_j
Data unit:	-
Description:	The average start date of commercial operation of power plants *j*
Source of data:	Determined as per Step 2 of the “Baseline emissions” section above
Measurement procedures (if any):	-
Any comment:	

III. MONITORING METHODOLOGY

All data collected as part of monitoring plan should be archived electronically and be kept at least for two years after the end of the last crediting period. One hundred per cent of the data should be monitored if not indicated otherwise in the comments in the tables below. All measurements should use calibrated measurement equipment according to relevant industry standards.

Data and parameters monitored

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh/yr
Description:	Total net quantity of electricity generated in the project plant and fed into the grid in year *y*
Source of data:	Measurements by project participants
Measurement procedures (if any):	Electricity meters

Monitoring frequency:	Continuously
QA/QC procedures:	The metered net electricity generation should be cross-checked with receipts from sales
Any comment:	Ensure that $EG_{PJ,y}$ is the net electricity generation (the gross generation by the project plant minus all auxiliary electricity consumption of the plant). If the actual average load factor during a monitoring period increases above the value of the load factor assumed for the proposed project activity in the CDM-PDD by more than 5% (or the upper end of the load factor values tested in the sensitivity analysis, if it is higher than 5%), then a request for approval of post-registration changes shall be submitted following the CDM "Project Cycle Procedure"

Data / Parameter:	$FC_{p,y}$
Data unit:	Mass or volume unit per year (e.g. ton/yr or m^3/yr)
Description:	Quantity of fossil fuel type *p* consumed by the project plant in year *y*
Source of data:	Onsite measurements
Measurement procedures (if any):	• Use either mass or volume meters. In cases where fuel is supplied from small daily tanks, rulers can be used to determine mass or volume of the fuel consumed, with the following conditions: The ruler gauge must be part of the daily tank and calibrated at least once a year and have a book of control for recording the measurements (on a daily basis or per shift); • Accessories such as transducers, sonar and piezoelectronic devices are accepted if they are properly calibrated with the ruler gauge and receiving a reasonable maintenance; • In case of daily tanks with pre-heaters for heavy oil, the calibration will be made with the system at typical operational conditions
Monitoring frequency:	Continuously
QA/QC procedures:	The consistency of metered fuel consumption quantities should be cross-checked by an annual energy balance that is based on purchased quantities and stock changes. Where the purchased fuel invoices can be identified specifically for the CDM project, the metered fuel consumption quantities should also be cross-checked with available purchase invoices from the financial records
Any comment:	Fossil fuel types *p* are those used in the project plant and that belong to the main fossil fuel category

Data / Parameter:	$FC_{q,y}$
Data unit:	Mass or volume unit per year (e.g. ton/yr or m^3/yr)
Description:	Quantity of fossil fuel type *q* consumed by the project plant in year *y*
Source of data:	Onsite measurements

Measurement procedures (if any):	Use either mass or volume meters. In cases where fuel is supplied from small daily tanks, rulers can be used to determine mass or volume of the fuel consumed, with the following conditions: • The ruler gauge must be part of the daily tank and calibrated at least once a year and have a book of control for recording the measurements (on a daily basis or per shift); • Accessories such as transducers, sonar and piezoelectronic devices are accepted if they are properly calibrated with the ruler gauge and receiving a reasonable maintenance; • In case of daily tanks with pre-heaters for heavy oil, the calibration will be made with the system at typical operational conditions
Monitoring frequency:	Continuously
QA/QC procedures:	The consistency of metered fuel consumption quantities should be cross-checked by an annual energy balance that is based on purchased quantities and stock changes. Where the purchased fuel invoices can be identified specifically for the CDM project, the metered fuel consumption quantities should also be cross-checked with available purchase invoices from the financial records
Any comment:	Fossil fuel types *q* are those used in the project plant and that belong to another fossil fuel category than the main fossil fuel category (i.e. auxiliary and start-up fuels)

Data / Parameter:	$FF_{i,y}$
Data unit:	Mass or volume unit per year (e.g. ton/yr or m^3/yr)
Description:	Quantity of fuel type *i* combusted in the project plant in year *y*
Source of data:	Onsite measurements
Measurement procedures (if any):	• Use either mass or volume meters. In cases where fuel is supplied from small daily tanks, rulers can be used to determine mass or volume of the fuel consumed, with the following conditions: The ruler gauge must be part of the daily tank and calibrated at least once a year and have a book of control for recording the measurements (on a daily basis or per shift); • Accessories such as transducers, sonar and piezoelectronic devices are accepted if they are properly calibrated with the ruler gauge and receiving a reasonable maintenance; • In case of daily tanks with pre-heaters for heavy oil, the calibration will be made with the system at typical operational conditions
Monitoring frequency:	Continuously
QA/QC procedures:	The consistency of metered fuel consumption quantities should be cross-checked by an annual energy balance that is based on purchased quantities and stock changes. Where the purchased fuel invoices can be identified specifically for the CDM project, the metered fuel consumption quantities should also be cross-checked with available purchase invoices from the financial records
Any comment:	-

Data / Parameter:	$NCV_{i,y}$
Data unit:	GJ per mass or volume unit (e.g. GJ/ton or GJ/m³)
Description:	Weighted average net calorific value of fuel type *i* in year *y*

<table>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>(a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source if the carbon fraction of the fuel is not provided (Option A), if there are many standard, which one is preferred?</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>If (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 upper limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (a) is not available</td></tr>
</table></td></tr>
<tr><td>Measurement procedures (if any):</td><td>For (a) and (b): Measurements should be undertaken in line with national or international fuel standards</td></tr>
<tr><td>Monitoring frequency:</td><td>For (a) and (b): the NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated.
For (c): review appropriateness of the values annually.
For (d): any future revision of the IPCC Guidelines should be taken into account</td></tr>
<tr><td>QA/QC procedures:</td><td>Verify if the values under (a), (b) and (c) are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in (a), (b) or (c) should have ISO17025 accreditation or justify that they can comply with similar quality standards</td></tr>
<tr><td>Any comment:</td><td>-</td></tr>
</table>

<table>
<tr><td>Data / Parameter:</td><td>$NCV_{p,y}$</td></tr>
<tr><td>Data unit:</td><td>GJ per mass or volume unit (e.g. GJ/ton or GJ/m³)</td></tr>
<tr><td>Description:</td><td>Average net calorific value of the fossil fuel type p consumed by the project plant in year y</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 if the carbon fraction of the fuel is not provided (Option A)</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>If (a) is not available

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</table></td></tr>
<tr><td>Measurement procedures (if any):</td><td>For (a) and (b): Measurements should be undertaken in line with national or international fuel standards</td></tr>
<tr><td>Monitoring frequency:</td><td>For (a) and (b): the NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated.
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<tr><td>Any comment:</td><td>Fossil fuel types p are those used in the project plant and that belong to the main fossil fuel category</td></tr>
</table>

<table>
<tr><td>Data / Parameter:</td><td>$NCV_{q,y}$</td></tr>
<tr><td>Data unit:</td><td>GJ per mass or volume unit (e.g. GJ/ton or GJ/m³)</td></tr>
<tr><td>Description:</td><td>Average net calorific value of the fossil fuel type q consumed by the project plant in year y</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 if the carbon fraction of the fuel is not provided (Option A)</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>If (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 upper limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (a) is not available</td></tr>
</table>
</td></tr>
<tr><td>Measurement procedures (if any):</td><td>For (a) and (b): Measurements should be undertaken in line with national or international fuel standards</td></tr>
<tr><td>Monitoring frequency:</td><td>For (a) and (b): the NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated.
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<tr><td>Any comment:</td><td>Fossil fuel types q are those used in the project plant and that belong to another fossil fuel category than the main fossil fuel category (i.e. auxiliary and start-up fuels)</td></tr>
</table>

Appendix

Specifications of power generation technologies

Power generation technology	Specifications	Minimum value of efficiency[11]
Solid fuels		
Subcritical technology	The operating pressure of the main steam boiler is equal to or lower than 22 MPa	38.7% with water cooling and 36.6% with air cooling
Supercritical technology	The operating pressure of the main steam boiler is above 22 Mpa. The operating temperature of the main steam boiler is below 593°C[12]	40.0%
Ultra-supercritical technology	The operating pressure of the main steam boiler is above 22 Mpa. The operating temperature of the main steam boiler is above 593°C	Not available
Gaseous fuels		
Single cycle technology	Includes a gas turbine(s) but no steam turbine	Not available
Combined cycle technology	Includes a gas turbine(s) and its exhaust heat is recovered to generate power by a steam turbine(s)	Not available

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History of the document

Version	Date	Nature of revision(s)
05.0.0	13 September 2012	EB 69, Annex 19 The revision: • Incorporates a more objective procedure to identify the baseline scenario; • Provides additional guidance for the investment comparison analysis for the demonstration of additionality; • Improves the procedure to determine the efficiency of the baseline technology; • Clarifies the data requirements and accounts for the potential impact of the data vintage of the plants used to determine the baseline efficiency through Approach/Option 2; • Changes the title from “Consolidated baseline and monitoring methodology for new grid connected fossil fuel fired power plants using a less GHG intensive technology” to “Construction and operation of new grid connected fossil fuel fired power plants using a less GHG intensive technology”.

[11] Calculated as the average of measured efficiencies of the above-average plants of the Chinese coal plants, as reported by the China Electricity Council in 2010. Conservative minimum efficiency values for other countries and other technologies may be proposed with appropriate substantiation through the “Procedure for the submission and consideration of requests for revision of AMs and tools for large scale CDM project activities”.

[12] International Energy Agency. 2010. Power Generation from Coal.

04.0.0	EB 56, Annex 7 17 September 2010	The revision: • Includes a definition for cogeneration plants; • Clarifies that the referential point in time for historical data, required in the calculation of baseline emissions, is the date of submission of the PDD for validation of the project activity; • Expands the applicability of the methodology to power plants that fire other fuel categories, than the main one, for start-up or auxiliary purposes; • Includes minor editorial improvements.
03	EB 53, Annex 7 26 March 2010	The revision concerns mainly the determination of the emission factor under the baseline and under the project scenario to ensure that emission reductions are limited to those resulting from the higher efficiency of the power generation technology used in the project activity as compared to the baseline.
02.1	EB 46, Annex 8 25 March 2009	The methodology was editorially revised: • To correct error in the unit in equation 2 and 3; • To correct unit conversion factor from GJ to MWh in equation 4; • To include $EF_{FF,PJ,CO2,y}$ in the monitoring table under 'data and parameters monitored'; and • To correct other unit inconsistencies and editorial errors.
02	EB 39, Annex 6 16 May 2008	The methodology was revised to clarify that in the fourth applicability condition the geographical area has to be limited by the physical borders of the host country and as such cannot be extended to neighboring non-Annex I countries.
01	EB 34, Annex 2 12 September 2007	Initial adoption.
Decision Class: Regulatory **Document Type**: Standard **Business Function**: Methodology		