CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 26 March 2010

CONTENTS

Annexes

SECTION A. General description of project activity

A.1. Title of the project activity:

>>
Title: Ultra-super-critical Coal Power Project

Version: 1.0

Date: 26 August 2010

A.2. Description of the project activity:

>>

The project participants consider to establish an ultra-super-critical coal power plant (hereinafter referred to as “the project”) with four 500 MW units, providing a total capacity of 2000 MW. The plant has an efficiency of 45%. The proposed project activity will supply the electricity grid to serve base load demand.

The project will contribute to the sustainable development in the Project host country and local area in the following ways:

- protection of climate through a better use of coal;
- conservation of non-renewable natural resources like coal by improving energy efficiency and reducing coal consumption per unit of electricity generated;
- supplying electricity to the local grid to help ease the existing electricity supply shortage, thus
- promoting local economic development;
- reducing SO2, NOx and flue gas dust through installing desulphurization and denitrification facilities.

Please note that this project is an example project for the purpose of demonstrating how the revised methodology is applied in the context of a CDM project activity. Please note further that the form F-CDM-AM-Rev and the “Procedures for the submission and consideration of requests for revision of approved baseline and monitoring methodologies and tools for large scale CDM project actitivites” only require to provide a PDD for an *example* project. Please note further that the above mentioned procedures require only that section B of this form is completed. In this example project additional information is provided in section A and section C.

A.3. Project participants:

>>
Forum Umwelt & Entwicklung (to be referred to as FUE hereafter)
Koblenzer Str. 65, 53173 Bonn, Germany

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

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A.4.1.1. Host Party(ies):

>>
India

A.4.1.2. Region/State/Province etc.:

>>
Still to be determined.

A.4.1.3. City/Town/Community etc.:

>>
Still to be determined.

A.4.1.4. Details of physical location, including information allowing the unique identification of this project activity (maximum one page):

>>
Still to be determined.

A.4.2. Category(ies) of project activity:

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This project falls into Category 1: "Energy industries (non renewable sources)".

A.4.3. Technology to be employed by the project activity:

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The project activity will employ coal fired super-critical technology for thermal power generation which has higher efficiency compared to the prevailing coal fired sub-critical technology. The main pieces of equipment for ultra-supercritical technology include the boiler, the steam turbine and the power generation unit.

A.4.4. Estimated amount of emission reductions over the chosen crediting period:

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Years	**Annual estimation of emission reductions in tonnes of CO2e**
2012	348,000
2013	873,898
2014	873,898
2015	873,898
2016	873,898
2017	873,898
2018	873,898
2019	436,949
Total estimated reductions (tonnes of CO2e)	6,028,334
Total number of crediting years	7 years

For a detailed calculation, please see Section B.6.3

A.4.5. Public funding of the project activity:

>>
No public funding is involved in the project activity.

SECTION B. Application of a baseline and monitoring methodology

B.1. Title and reference of the approved baseline and monitoring methodology applied to the project activity:

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The methodology applied is version 4 of ACM0013: **"Consolidated baseline and monitoring methodology for new grid connected fossil fuel fired power plants using a less GHG intensive technology"**, as included as draft revised methodology in the request for revision

B.2. Justification of the choice of the methodology and why it is applicable to the project activity:

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The methodology is applicable under the following conditions:

- The project activity is the construction and operation of a new fossil fuel fired grid-connected electricity generation plant that uses a more efficient power generation technology than what would otherwise be used with the given fossil fuel category;

- One 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, but they shall not comprise more than 3% of the total fuel used annually on an energy basis;

- The project activity does not include the construction and operation of a co-generation power plant;

- Data on fuel consumption and electricity generation of recently constructed power plants are available;

- The identified baseline fuel category is used in more than 50% of total generation by utilities in the geographical area within the host country, as defined later in the methodology, or in the entire host country. To demonstrate this applicability condition data from the latest three years shall be used. Maximum value of same fossil fuel generation estimated for three years should be greater than 50%.

The project meets all of these conditions:

- The project activity is the construction and operation of a new fossil fuel fired grid-connected electricity generation plant that uses ultra-supercritical technology, a more efficient power generation technology than what would otherwise be used with the given fossil fuel;
- The project activity is not a co-generation power plant;
- Data on fuel consumption and electricity generation of recently constructed power plants is available.
- The identified baseline fuel is coal, used in more than 50% by utilities in the geographical area in the host country.

B.3. Description of the sources and gases included in the project boundary:

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The spatial extent of the project boundary includes the four 500 MW power plants at the project site and all power plants considered for the calculation of the baseline CO_2 emission factor ($EF_{BL,CO2}$).

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

B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

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Step 1: Identify plausible baseline scenarios

As stipulated in the methodology the identification of alternative baseline scenarios includes 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).

The following Alternatives have been identified and analyzed below:

Alternative 1. The project activity not implemented as a CDM project

The alternative is realistic and credible and in compliance with all local and national laws and regulations. ***The alternative will be considered for further assessment.***

Alternative 2. Power generation using coal-fired sub-critical power generation technologies

The alternative is realistic and credible and in compliance with all local and national laws and regulations. ***The alternative will be considered for further assessment.***

Alternative 3. Power generation using natural gas

In the region where the project is established and where the electricity demand must be met, natural gas is not available and is very unlikely to become available in the coming years. In the absence of assured and reliable gas supply, availability of natural gas for power generation is not realistic. ***Hence this alternative is not considered further for arriving at the baseline scenario.***

Alternative 4: Power generation using fuel oil/diesel/naphtha

In the location where the power plant is planned to be constructed, there is not sufficient pipeline capacity to supply the plant with oil, diesel or naphta. Constructing a new pipeline would require many years and is not a feasible option. Road or water transportation are also not feasible to this extent in the area of the power plant. In contrast, coal can be directly mined nearby the place where the power plant is planned to be constructed. ***Hence this alternative is not considered further for arriving at the baseline scenario.***

Alternative 5. Power generation using renewable energy sources

In this alternative scenario, the project proponent could have considered generation of power using renewable energy sources which includes hydro power, wind power, biomass energy etc. In this option there would be no GHG emissions and this alternative is in compliance with all applicable laws and regulations of the country. However, generation of power with a base load capacity of 2000 MW using renewable resources like small hydro, wind, biomass etc is not a technically feasible option: sufficient hydro power capacity is not available in the region. Similarly, the biomass is scarce and sufficient dedicated plantations or biomass residues would not be available in the region. Wind and hydro power can not be used to serve a base load demand and thus would not provide the same service as the project activity. ***Hence this alternative is not considered further for arriving at the baseline scenario.***

Alternative 6. Power generation using nuclear

The government of the host country does not allow the specific project participants to use nuclear energy. Moreover, the construction of nuclear power plants requires many years and the baseline load power demand of the project is needed in the region at an earlier stage. ***Hence this alternative is not considered further for arriving at the baseline scenario.***

Alternative 7: Import of electricity from connected grids, including the possibility of new

The import of power by India has historically been below 0.5% of total power consumption. Considering this historical trend of import of power and also considering the fact that large scale power import in India is constrained by inadequate power transmission infrastructure and lack of grid integration among neighboring countries, it can be concluded that the import of electricity from connected grids is not a realistic and credible alternative and the imported amount of electricity will not be sufficient to meet the power deficit situation in India. ***Hence this alternative is not considered any further.***

Step 2: Identify the economically most attractive baseline scenario alternative

The economically most attractive baseline scenario alternative is identified using investment analysis. As per the guidance of the methodology the levelized cost of electricity generation in INR/kWh has been used as financial indicator for comparison of economic attractiveness of baseline alternatives.
The major assumptions to arrive at the levelized cost of power generation have been tabulated below.

Parameters	Unit	Data for the project plant (alternative 1)	Data source alternative 1	Data for alternative 2	Data source for alternative 2
Project Size	MW	2000	Grid requirement	2000	Grid requirement
Investment Cost	US$ / kW	1600	Manufacturer offer	1200	Manufacturer offer
Debt to Equity	Ratio	75/25	Management requirement for the project company	75/25	Management requirement for the project company
Cost of debt	Percentage	11	Offer by relevant bank	11	Offer by relevant bank
Cost of equity	Percentage	14	This value has consistently been used for other projects	14	This value has consistently been used for other projects
O & M cost (variable)	Percentage of investment per year	5	CERC guideline	2.5	Manufacturer guaranteed service package
Escalation for O & M costs	Percentage	4	Manufacturer guaranteed service package	4	Manufacturer guaranteed service package
Plant life	years	25	Manufacturer information	25	Manufacturer information
PLF	Percentage	86	Manufacturer guaranteed availability	86	Manufacturer guaranteed availability
Net efficiency	Percentage	45	Manufacturer offer	38	Manufacturer offer
Fuel price per tonne of coal	US$ / ton		coal supply agreement		National study on coal prices
Fuel Price Escalation Percentage	% / year	5	National study on coal prices	5	National study on coal prices
NCV of coal	GJ/t	16	Laboratory tests	16	Laboratory tests

Based on the data provided in the table, the weighted average cost of capital used for the analysis corresponds to 11,75%. The table below illustrates costs during the first ten years of operation, including investment costs, fuel costs and operational costs, for both alternatives.

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Alternative 1											
Investment costs	1.000.000 US$	3.200									
Electricity generation	MWh	6.000.000	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200
Fuel consumption	tons	3.000.000	7.533.600	7.533.600	7.533.600	7.533.600	7.533.600	7.533.600	7.533.600	7.533.600	7.533.600
Fuel price	US$ / ton	70	74	77	81	85	89	94	98	103	109
Fuel costs	1.000.000 US$	210	554	581	610	641	673	707	742	779	818
Operational costs	1.000.000 US$	64	166	173	180	187	195	202	211	219	228
Total costs	1.000.000 US$	3.474	720	754	790	828	868	909	953	998	1.046
Net present value of total costs	1.000.000 US$	10.506									
Levelized total costs	1.000.000 US$	1.316	1.316	1.316	1.316	1.316	1.316	1.316	1.316	1.316	1.316
Levelized generation costs	**US$ / MWh**		**87,36**								
Alternative 2											
Investment costs	1.000.000 US$	2.400									
Electricity generation	MWh	6.000.000	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200	15.067.200
Fuel consumption	tons	3.552.632	8.921.368	8.921.368	8.921.368	8.921.368	8.921.368	8.921.368	8.921.368	8.921.368	8.921.368
Fuel price	US$ / ton	70	74	77	81	85	89	94	98	103	109
Fuel costs	1.000.000 US$	249	656	689	723	759	797	837	879	923	969
Operational costs	1.000.000 US$	24	62	65	67	70	73	76	79	82	85
Total costs	1.000.000 US$	2.673	718	753	790	829	870	913	958	1.005	1.054
Net present value of total costs	1.000.000 US$	9.854									
Levelized total costs	1.000.000 US$	1.235	1.235	1.235	1.235	1.235	1.235	1.235	1.235	1.235	1.235
Levelized generation costs	**US$ / MWh**		**81,95**								

The result of the calculation is shown below.

Economic analysis of all the realistic and credible alternatives in absence of the proposed project activity		
Project type:	Alternative 1	Alternative 2
Levelized Cost of Electricity Generation (US$/MWh)	87,36	81,95

Our analysis shows that power generation with alternative 2 is the economically more attractive option than power generation with alternative 1. The following table illustrates the result of a sensitivity analysis undertaken. The only key parameter which is sensitive is the coal price. Investment costs and operational costs are guaranteed by the technology provider in a service package for both options. The table shows the results for a 30% higher and a 30% lower coal price. The result of the analysis that alternative 2 is economically more attractive holds for both higher and lower coal prices.

Results of the sensitivity analysis – Levelized costs of electricity generation (US$/MWh)		
Project type:	Alternative 1	Alternative 2
30 % higher coal price	102,29	99,62
30% lower coal price	72,44	64,27

As the sensitivity analysis confirms the result of the analysis above, alternative 2 represents the baseline scenario.

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity (assessment and demonstration of additionality):

>>

The “Tool for the demonstration and assessment of additionality” (version 05.2) has been used to demonstrate the additionality of the Project.

Step 1 was conducted in section B.4 above. The barrier analysis (Step 2 of the tool) is skipped. Step 3 of the tool largely corresponds to Step 2 in section B.4 and has been conducted in that section. Given that another option (subcritical coal power generation) is economically more attractive, Hence, in this section only step 4 of the tool is applied.

Step 4: Common practice analysis

The plant uses a technology (ultra-super-critical power generation) which has so far not been applied in India. The heat rate is lower than the heat rate of any other coal fired power generation in India. In this regard, the project is the first-of-its-kind and not common practice in the host country.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

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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:

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

Where:

PE_y	=	Project emissions in year *y* (tCO_2)
$FF_{i,y}$	=	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 (tCO_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 ($EG_{PJ,main\_FF,y}$)[1] with a baseline CO_2 emission factor ($EF_{BL,CO2}$), as follows:

$$BE_y = EG_{PJ,main\_FF,y} \times EF_{BL,CO2} \qquad \textbf{(2)}$$

and

[1] 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.

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

Where:

BE_y	=	Baseline emissions in year *y* (tCO_2)
$EG_{PJ,main\_FF,y}$	=	Net quantity of electricity generated in the project plant from using fossil fuel types within the main fossil fuel category in year *y* (MWh)
$EG_{PJ,y}$	=	Total net quantity of electricity generated in the project plant in year *y* (MWh)
$EF_{BL,CO2}$	=	Baseline emission factor (tCO_2/MWh)
$FC_{p,y}$	=	Quantity of fossil fuel type *p* consumed by the project plant in year *y* (Mass or volume unit)
$NCV_{p,y}$	=	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)
$NCV_{q,y}$	=	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 lowest 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 fuel category as the project plant and any technology available in the geographical area as defined in Step 2 below.

Consequently, project participants shall use for $EF_{BL,CO2}$ the lowest value among the following two options:

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

$$EF_{BL,CO2} = 3.6 \cdot \frac{MIN\left(EF_{FF,BL,CO2};EF_{FF,CO2}\right)}{\eta_{BL}} \quad \textbf{(4)}$$

Where:

$EF_{BL,CO2}$	=	Baseline emission factor (tCO_2/MWh)
$EF_{FF,BL,CO2}$	=	CO_2 emission factor of the fossil fuel type that has been identified as the most likely baseline scenario (tCO_2/GJ)
$EF_{FF,CO2}$	=	CO_2 emission factor of the fossil fuel type used in the project and the baseline (tCO_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

Option 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 autonomous technical improvement that that would have occurred between the investment decision on the power plants *j* and the investment decision on the project activity, as follows:

$$EF_{BL,CO2} = \frac{EF_{FF,CO2}}{\left(\eta_{avg,j} + \Delta\eta \cdot d\right)} \cdot 3.6 \qquad \textbf{(5)}$$

with

$$\eta_{avg,j} = 3.6 \cdot \frac{\sum_j EG_{j,v}}{\sum_j FC_{j,v} \cdot NCV_{j,v}} \qquad \textbf{(6)}$$

Where:

$EF_{BL,CO2}$	=	Baseline emission factor (tCO_2/MWh)
$EF_{FF,CO2}$	=	CO_2 emission factor of the fossil fuel type used in the project and the baseline (tCO_2/GJ)
$\eta_{avg,j}$	=	Weighted average efficiency of power plants *j*
$\Delta\eta$	=	Average annual efficiency improvement for newly constructed power plants would likely have occurred due to autonomous 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 (1 / year)
d	=	Data vintage, expressing the time difference between the start of commercial operation of the proposed project activity and the middle point in time within the four year period preceding the reference year *v* in which the power plants *j* started commercial operation (years)
$EG_{j,v}$	=	Net electricity generated and delivered to the grid by power plant *j* in reference year *v* (MWh)
$FC_{j,v}$	=	Amount of fuel consumed by power plant *j* in reference year *v* (Mass or volume unit)
$NCV_{j,v}$	=	Average net calorific value of the fossil fuel type consumed by power plant *j* in reference year *v* (GJ/Mass or volume unit)
j	=	The top 15% performing power plants (excluding cogeneration plants and including power plants registered as CDM project activities), as identified below, among all power plants in a defined geographical area that have a similar size, are operated at similar load and use a fuel type within the same fuel category as the project activity

For determination of the top 15% performer power plants *j*, the following step-wise approach is used:

Step 1: Definition of similar plants to the project activity

The sample group of similar power plants should consist of all power plants (except for cogeneration power plants).

- That use the same fossil fuel category 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 fuel used annually by the sample power plant on an energy basis;
- That started commercial operation within the four year period preceding the reference year *v*, where the last year of this 5 years period should be the reference year *v*;
- That have a comparable size to the project activity, defined as the range from 50% to 150% 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 operated (supplied electricity to the grid) in the reference year *v*.

Step 2: Definition of the geographical area

The geographical area to identify similar power plants should be chosen in a manner that the total number of power plants *N* in the sample group comprises at least 10 plants. As a default, the grid[2] to which the project plant will be connected should be used. If the number of similar plants, as defined in Step 1, within the grid boundary is less than 10, the geographical area should be extended to 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. If the number remains to be less than 10, all non-Annex I countries in the continent should be considered.

If the necessary data on power plants of the sample group 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 data from power plants Annex I or OECD countries can be used instead for the remaining plants required to complete the sample group.

Step 3: Identification of the sample group

Identify all power plants *n* that are to be included in the sample group. Determine the total number *N* of all identified power plants that use the same fuel as the project plant and any technology available within the geographical area, as defined in Step 2 above.

The sample group should also include all power plants within the geographical area registered as CDM project activities, which meet the criteria defined in Step 1 above.

Step 4: Determination of the plant efficiencies

[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.

Calculate the operational efficiency of each power plant *n* identified in the previous step. The most recent one-year data available shall be used. The operational efficiency of each power plant *n* in the sample group is calculated as follows:

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

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)
$FC_{n,v}$	=	Quantity of fuel consumed in the power plant *n* in the reference year *v* (Mass or volume unit)
$NCV_{n,v}$	=	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 in the defined geographical area that have a similar size, are operated at similar load and use a fuel type within the same fuel category as the project activity

Step 5: Identification of the top 15% performer plants j

Sort the sample group of *N* plants from the power 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 3) and 15%, rounded down if it is decimal.[3] 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 sample group), 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*.

All steps should be documented transparently, including a list of the plants identified in Steps 3 and 5, as well as relevant data on the fuel consumption and electricity generation of all identified power plants.

For the determination of $\Delta\eta$, project participants may choose between the following options:

Option A: Calculation based on historical autonomous technical improvements observed in the applicable geographical area. Determine $\Delta\eta$ based on an average annual improvement in the efficiency of newly constructed power plants observed over a period of ten years in the applicable geographical area by applying a regression analysis. This option can only be used if the regression analysis provides a value for $\Delta\eta \geq 0$ and the coefficient of determination $R^2 \geq 0.7$. Apply and document in the CDM-PDD the following steps:

- Identify all power plants *m* within the applicable geographical area, as determined in step 3 above,

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[3] 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.

- that use the same fossil fuel category 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 fuel used annually by the sample power plant on an energy basis;
- 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 150% 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 operated (supplied electricity to the grid) in the reference year *v*.

- Determine for each plant *m* the operational efficiency $\eta_{m,v}$ in the year *v*, by applying equation (7) in step 4 above for all power plants *m*, and the year in which the plant started commercial operation.
- Plot the efficiency of all power plants *m* over the date in which the power plants started commercial operation and apply a linear regression analysis and determine the average annual efficiency improvement $\Delta\eta$ as a function of the date of construction using the method of least squares.
- Determine the data vintage *d*, expressed in years, as the time difference between the start of commercial operation of the proposed project activity and the middle point in time within the four year period preceding the reference year *v* in which the power plants *j* started commercial operation.

Option B: Use a conservative default value. Use for $\Delta\eta$ a conservative default value of 0.5%.

Option B is applied to this example project.

LEAKAGE

No leakage emissions are to be considered.

EMISSION REDUCTIONS

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

$$ER_y = BE_y - PE_y \quad \textbf{(8)}$$

Where:

ER_y	=	Emission reductions in year *y* (tCO_2)
BE_y	=	Baseline emissions in year *y* (tCO_2)
PE_y	=	Project emissions in year *y* (tCO_2)

B.6.2. Data and parameters that are available at validation:

Data / Parameter:	$EF_{FF,BL,CO2}$
Data unit:	tCO_2/GJ
Description:	CO_2 emission factor of the fossil fuel type that has been identified as the most likely baseline scenario
Source of data:	IPCC default values for the respective fuel type 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
Value applied	0.0928
Justification of the choice of data or description of measurement methods and procedures actually applied :	This is the value provided in the 2006 IPCC Guidelines for sub-bituminous coal which is the only fuel that can be used in the project plant and in the baseline plant.
Any comment:	-

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:	Offer by the manufacturer
Value applied	0.38
Justification of the choice of data or description of measurement methods and procedures actually applied :	-
Any comment:	-

Data / Parameter:	$FC_{j,v}$ and $FC_{n,v}$
Data unit:	Mass or volume unit
Description:	Amount of fuel consumed by power plant *j* or *n* in the reference year *v*, where: • *j* are the top 15% performer plants among all power plants in a defined geographical area that have a similar size, are operated at similar load and use a fuel type within the same fuel category as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section; • *n* are all power plants (including power plants registered as CDM project activities) in the defined geographical area that have a similar size, are operated at similar load and use a fuel type within the same fuel category as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section

Source of data:	Electricity authority in the host country
Value applied:	See respective data tabled in section B.6.3 below
Justification of the choice of data or description of measurement methods and procedures actually applied :	-
Any comment:	

Data / Parameter:	$NCV_{j,v}$ and $NCV_{n,v}$
Data unit:	GJ/tonne
Description:	Average net calorific value of the fossil fuel type consumed by power plant *j* or *n* in the reference year *v*, where: • *j* are the top 15% performer plants among all power plants in a defined geographical area that have a similar size, are operated at similar load and use a fuel type within the same fuel category as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section; • *n* are all power plants (including power plants registered as CDM project activities) in the defined geographical area that have a similar size, are operated at similar load and use a fuel type within the same fuel category as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section
Source of data:	Electricity authority in the host country
Value applied:	See respective data tabled in section B.6.3 below
Justification of the choice of data or description of measurement methods and procedures actually applied :	-
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 for sub-bituminous coal at the lower limit of the 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories.
Value applied:	0.0928
Justification of the choice of data or description of	This is the value provided in the 2006 IPCC Guidelines for sub-bituminous coal which is the only fuel that can be used in the project plant and in the baseline plant.

measurement methods and procedures actually applied :	
Any comment:	-

Data / Parameter:	$EG_{j,v}$ and $EG_{n,v}$
Data unit:	MWh
Description:	Net electricity generated and delivered to the grid by power plant *j* or *n* in the reference year *v*, where: • j are the top 15% performer plants among all power plants in a defined geographical area that have a similar size, are operated at similar load and use a fuel type within the same fuel category as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section; • *n* are all power plants (including power plants registered as CDM project activities) in the defined geographical area that have a similar size, are operated at similar load and use a fuel type within the same fuel category as the project activity and any technology available within the geographical area, as defined in Step 2 under "Baseline emissions" section
Source of data:	Electricity authority in the host country
Value applied:	See respective data tabled in section B.6.3 below
Justification of the choice of data or description of measurement methods and procedures actually applied :	-
Any comment:	-

Data / Parameter:	$\Delta\eta$
Data unit:	1 / year
Description:	Average annual efficiency improvement of newly constructed power plants (1 / year)
Source of data:	Option B in ACM0013 version 4
Value applied:	0.5%
Justification of the choice of data or description of measurement methods and procedures actually applied :	Because of lack of data, option B was chosen.
Any comment:	-

Data / Parameter:	d
Data unit:	years
Description:	Vintage between the start of commercial operation of the proposed project activity and the middle point in time within the four year period preceding the reference year *v* (years)
Source of data:	Documented evidence on the planned start of commercial operation of the proposed project activity
Value applied:	6.5
Justification of the choice of data or description of measurement methods and procedures actually applied :	Expected project start July 2012 Reverence year v is 2008 The four year period in which power plants j started commercial operation then corresponds to 1 January 2004 to 31 December 2007. The middle point in time within this period is 1 January 2006. The vintage is 6.5 years (the difference expressed in years between 1 July 2012 and 1 January 2006).
Any comment:	

B.6.3. Ex-ante calculation of emission reductions:

>>

Baseline emissions

The project plant uses only coal and no other start-up or auxiliary fuels. Four units of 500 MW are established as part of the project activity. The plant load factor is expected to be 86%. This results in an annual electricity generation of about 15 TWh. The expected electricity generation from 2012 to 2018 is illustrated in the table below.

Year	**Expected power generation**
2012	6,000,000
2013	15,067,200
2014	15,067,200
2015	15,067,200
2016	15,067,200
2017	15,067,200
2018	15,067,200

In the following, the calculation of the baseline emission factor EF is documented for both options. The reference year *v* for the calculations is 2008, as this is the latest year for which data is available.

Option 1

Under option 1, the baseline emission factor is determined as follows:

$$EF_{BL,CO2} = 3.6 \cdot \frac{MIN\left(EF_{FF,BL,CO2}; EF_{FF,CO2}\right)}{\eta_{BL}}$$

The project activity uses sub-bituminous coal. The same fuel type would be used in the baseline scenario. The CO_2 emission factor for the fuel type is thus for both the project and the baseline 0,0928 t CO2 / GJ. As per the methodology requirements, this corresponds to the lower end of the range of the IPCC default value for sub-bituminous coal in the 2006 IPCC Guidelines.

The efficiency of the baseline power plant, as identified in the procedure to select the baseline scenario, is 38%. The corresponding baseline emission factor for option 1 ($EF_{BL,CO2}$) is then:

$EF_{BL,CO2}$ = 3.6 x 0,0928 / 38% = 0,879 t CO_2 / MWh

<u>Option 2</u>

For determining the power plants j, it is required to identify all similar power plants in the applicable region. In the following example, 10 power plants of similar size of the units (250 to 750 MW) have been identified. The capacity, electricity generation, fuel consumption and net calorific value of the main fuel used are illustrated in the table below. The efficiency is calculated for each plant as per equation (7) in step 4 of the procedure to determine the power plants j.

Name of Plant	**Capacity**	**$EG_{n,v}$**	**$FC_{n,v}$**	**$NCV_{j,v}$**	**$\eta_{n,v}$**
Data Unit	**MW**	**MWh**	**tonnes**	**GJ/tonne**	**GJ/tonne**
Plant 1	670	4.900.547	3.405.786	14	37,0%
Plant 2	670	4.662.935	3.285.042	14	36,5%
Plant 3	700	5.203.415	3.568.056	14	37,5%
Plant 4	260	1.888.901	1.151.769	16,4	36,0%
Plant 5	530	3.774.111	2.657.825	14,4	35,5%
Plant 6	420	2.734.519	1.900.438	14	37,0%
Plant 7	500	3.485.101	2.292.830	14,4	**38,0%**
Plant 8	260	1.656.929	1.060.435	15	37,5%
Plant 9	720	4.868.183	3.291.166	15	35,5%
Plant 10	500	3.531.033	2.671.651	12,2	**39,0%**
TOTAL		36.705.674			

Plant 10 is the most efficient plant. However, this plant only generates only 9.6% of the total electricity generated by the sample plants. Plant 7 is the second most efficient plant. The two plants together generate 19.1% of the total electricity generated by the sample plants. Therefore, these two plants constitute the sub-sample of the top 15% performing power plants j. The weighted average efficiency of these power plants is then calculated as per equation (6) of the methodology, as follows:

$$\eta_{avg,j} = 3.6 \cdot \frac{\sum_j EG_{j,v}}{\sum_j FC_{j,v} \cdot NCV_{j,v}} = 3.6 \cdot \frac{3485101 + 3531033}{292830 * 14.4 + 2671651 * 12,2} = 38,497\%$$

For the determination of Δη, option B is chosen and a value 0.5% is applied. The data vintage d corresponds to 6,5 years. The plant is scheduled to be commissioned on 1 July 2012. The reference year v is 2008. The four year period in which power plants j started commercial operation then corresponds to 1 January 2004 to 31 December 2007. The middle point in time within this period is 1 January 2006.

The emission factor for option 2 is then calculated as per equation (5) of the methodology as follows:

$$EF_{BL,CO2} = \frac{EF_{FF,CO2}}{\left(\eta_{avg,j} + \Delta\eta \cdot d\right)} \cdot 3.6 = \frac{0.0928}{(38{,}497\% + 0{,}5\% * 6.5)} * 3.6 = 0{,}800 \ \text{tCO2/MWh} \qquad \textbf{(9)}$$

The emission factor under option 2 is thus lower than under option 1. Thus, the value from option 2 (0,8 tCO_2/MWh) applies for the baseline emission factor ($EF_{BL,CO2}$).

The project plant has an efficiency of 45% and uses the same fuel type. It has thus an emission factor of 0,742 tCO_2/MWh. The expected baseline emission, project emissions and emission reductions are illustrated in the table below.

Year	$EG_{PJ,y}$	$EF_{BL,CO2}$	BE_y	Emission factor of the project plant	PE_y	ER_y
	MWh	tCO2/MWh	tCO2	tCO2/MWh	tCO2	tCO2
2012	6.000.000	0,800	4.800.000	0,742	4.452.000	348.000
2013	15.067.200	0,800	12.053.760	0,742	11.179.862	873.898
2014	15.067.200	0,800	12.053.760	0,742	11.179.862	873.898
2015	15.067.200	0,800	12.053.760	0,742	11.179.862	873.898
2016	15.067.200	0,800	12.053.760	0,742	11.179.862	873.898
2017	15.067.200	0,800	12.053.760	0,742	11.179.862	873.898
2018	15.067.200	0,800	12.053.760	0,742	11.179.862	873.898
2019	7.533.600	0,800	6.026.880	0,742	5.589.931	436.949
Total			**83.149.440**		**77.121.106**	**6.028.334**

B.6.4 Summary of the ex-ante estimation of emission reductions:

>>

The following table shows a summary of the ex-ante estimation of emission reductions.
Expected start date July 2012

Years	**Annual estimation of emission reductions in tonnes of CO2e**
2012	**348,000**
2013	**873,898**
2014	**873,898**
2015	**873,898**
2016	**873,898**
2017	**873,898**
2018	**873,898**
2019	**436,949**

Total estimated reductions (tonnes of CO2e)	**6,028,334**
Total number of crediting years	**7 years**

B.7. Application of the monitoring methodology and description of the monitoring plan:

All data collected as part of monitoring plan will be archived electronically and be kept at least for 2 years after the end of the last crediting period. One hundred per cent of the data will be monitored if not indicated otherwise in the comments in the tables below. All measurements will use calibrated measurement equipment according to relevant industry standards.

B.7.1 Data and parameters monitored:

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh
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)

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:	Continously
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:	Continously
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:	-

<table>
<tr><td>Data / Parameter:</td><td>$NCV_{i,y}$</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>Weighted average net calorific value of fuel type i 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>
</table>

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

Monitoring frequency:	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

QA/QC procedures:	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
Any comment:	-

Data / Parameter:	$NCV_{p,y}$
Data unit:	GJ per mass or volume unit (e.g. GJ/ton or GJ/m³)
Description:	Average net calorific value of the fossil fuel type *p* consumed by the project plan in year *y*
Source of data:	The following data sources may be used if the relevant conditions apply:

Data source	Conditions for using the data source
(a) Values provided by the fuel supplier in invoices	This is the preferred source if the carbon fraction of the fuel is not provided (Option A)
(b) Measurements by the project participants	If (a) is not available
(c) Regional or national default values	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).
(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	If (a) is not available

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

Monitoring frequency:	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

QA/QC procedures:	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
Any comment:	Fossil fuel types *p* are those used in the project plant and that belong to the main fossil fuel category

<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 plan 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
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>Fossil fuel types q are those used in the project plant and that belong to another</td></tr>
</table>

	fossil fuel category than the main fossil fuel category (i.e. auxiliary and start-up fuels)

B.7.2. Description of the monitoring plan:

>>
The project will be managed by the project proponent who will follow all regulatory and statutory requirements as prescribed under the state and central laws and regulations. A CDM project team will be established at the plant site. The project team will have the responsibility of recording and storing the data related to the project activity. The project team will be also responsible for calculation of actual creditable emission reduction in the most transparent manner. Installed meters will be calibrated according to the maintenance schedule programmed at the start of the operation and will be recalibrated, at regular intervals, according to the plant's performance requirements. Any change within the project boundary, such as change in spare and or equipments will be recorded and any change in the emission reduction due to such alteration will also be studied and recorded.

B.8. Date of completion of the application of the baseline study and monitoring methodology and the name of the responsible person(s)/entity(ies):

>>
25 August 2010
Responsible entity: Forum Umwelt und Entwicklung

SECTION C. Duration of the project activity / crediting period

C.1. Duration of the project activity:

C.1.1. Starting date of the project activity:

>>
1 July 2012

C.1.2. Expected operational lifetime of the project activity:

>>
25 years

C.2. Choice of the crediting period and related information:

C.2.1. Renewable crediting period:

C.2.1.1. Starting date of the first crediting period:

>>
1 January 2011 or the official registration date in UNFCCC, whichever is later

C.2.1.2. Length of the first crediting period:

>>
7 years (to be renewed up to 21 years in total)

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>>
Not applicable

C.2.2.2. Length:

>>
Not applicable

SECTION D. Environmental impacts

>>

D.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:

>>

D.2. If environmental impacts are considered significant by the project participants or the host Party, please provide conclusions and all references to support documentation of an environmental impact assessment undertaken in accordance with the procedures as required by the host Party:

>>

SECTION E. Stakeholders' comments

>>

E.1. Brief description how comments by local stakeholders have been invited and compiled:

>>

E.2. Summary of the comments received:

>>

E.3. Report on how due account was taken of any comments received:

>>

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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URL:	
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Salutation:	Ms
Last name:	Filzmoser
Middle name:	
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Direct FAX:	
Direct tel:	00 32 2 893 08 94
Personal e-mail:	eva.filzmoser@cdm-watch.org

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

Annex 3

BASELINE INFORMATION

Annex 4

MONITORING INFORMATION

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