CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006

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Annexes

Appendices

SECTION A. General description of project activity

A.1. Title of the project activity:

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Title: Natural gas based combined cycle power plant in Tripura, India
Version: 07
Date: 06/12/2012

A.2. Description of the project activity:

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The project activity is a Natural Gas based power plant that utilizes the natural gas resources available in surplus in the state of Tripura, India. The power plant would be a Combined Cycle Gas Turbine (CCGT) power plant with gross generation capacity of 726.6 MW at Pallatana, Tripura. It would be based on ONGC's gas supply and would be implemented through a single Special Purpose Vehicle (SPV) called ONGC - Tripura Power Company Ltd (OTPC) incorporated on 27/09/2004. OTPC is promoted by Government of Tripura (GoT), Infrastructure Leasing & Financial Services Ltd (IL&FS) and Oil & Natural Gas Corporation (ONGC).

The project envisages using two units of capacity 363.3 MW Combined Cycle Gas Based Turbine (CCGT) sets (232.39 MW Gas Turbine and 130.91 MW Steam Turbine Generator). OTPC envisages the sale of its generated electrical power to the North Eastern states viz. Assam, Tripura, Manipur, Meghalaya, Nagaland, Arunachal Pradesh, Mizoram that are connected to the NEWNE grid and 13.5% to any entity in the country through the regional grid. The average net saleable energy exported from the proposed project activity will be 5,197 GWh per annum.

In the baseline scenario, similar quantum of electricity would have been generated from the operation of grid-connected power plants and by the addition of new generation sources that predominantly consist of fossil fuel fired plants. This would consequently have led to the emission of a greater quantum of greenhouse gases.

Contribution of the project activity to sustainable development:

Ministry of Environment and Forests, Govt. of India has stipulated the following indicators for sustainable development in the interim approval guidelines for CDM projects[1]:

⇒ **Social well being**

The CDM project activity should lead to alleviation of poverty by generating additional employment, removal of social disparities and contribution to provision of basic amenities to people leading to improvement in quality of life of people.

- Project developer's contribution will be towards providing employment opportunities during construction stage and operation stage, thereby improving the quality of life of the people in surrounding habitations.
- The project will lead to development of the road and telecommunication network and improvement in the local infrastructure that would boost the development and social upliftment of the region.

[1] http://cdmindia.nic.in/host_approval_criteria.htm

⇒ **Economic well-being**

The CDM project activity should bring in additional investment consistent with the needs of the people.

- The project activity will bring in a substantial investment into the region that will contribute to the local economy as well as set an example to other industries over the suitability of the region for investment.
- The project developer would be directly/indirectly creating business opportunities for stakeholders like bankers, consultants, suppliers, manufacturers, contractors, traders, caterers etc. in the region.
- Project developer's contribution will be towards providing employment opportunities during construction stage and operation stage, thereby improving the quality of the life of people in surrounding habitations.

⇒ **Environmental well being**

This should include a discussion of impact of the project activity on resource sustainability and resource degradation, if any, due to proposed activity; bio-diversity friendliness; impact on human health; reduction of levels of pollution in general.

- Project activity would export around 5,197 GWh of cleaner power to NEWNE grid, thereby eliminating the generation of same quantity of energy from any addition to the grid in the form of more carbon intensive mix.
- It would lead to conservation of coal, making it available for other important applications.

⇒ **Technological well being**

The CDM project activity should lead to transfer of environmentally safe and sound technologies with a priority to the renewable sector or energy efficiency projects that are comparable to best practices in order to assist in up-gradation of technological base.

- The project activity would promote the technology of power generation using Combined Cycle process in Natural Gas based power plants in the region. The technology being utilised is based on advanced class machines of 9FA technology that is environmentally safe and sound and is being used for the first time in the North Eastern region.
- The project is also the first mega power project (>700 MW capacity) in the North Eastern region which would promote further investment in this kind of technology in the region.

A.3. Project participants:

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Name of Party involved ((host) indicates a host Party)	Private and/or public entity(ies) project participants (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
India (Host country)	• ONGC Tripura Power Company Limited (OTPC) • Oil and Natural Gas Corporation Ltd. (ONGC)	No

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.:

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Tripura

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

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Village / City: Pallatana

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

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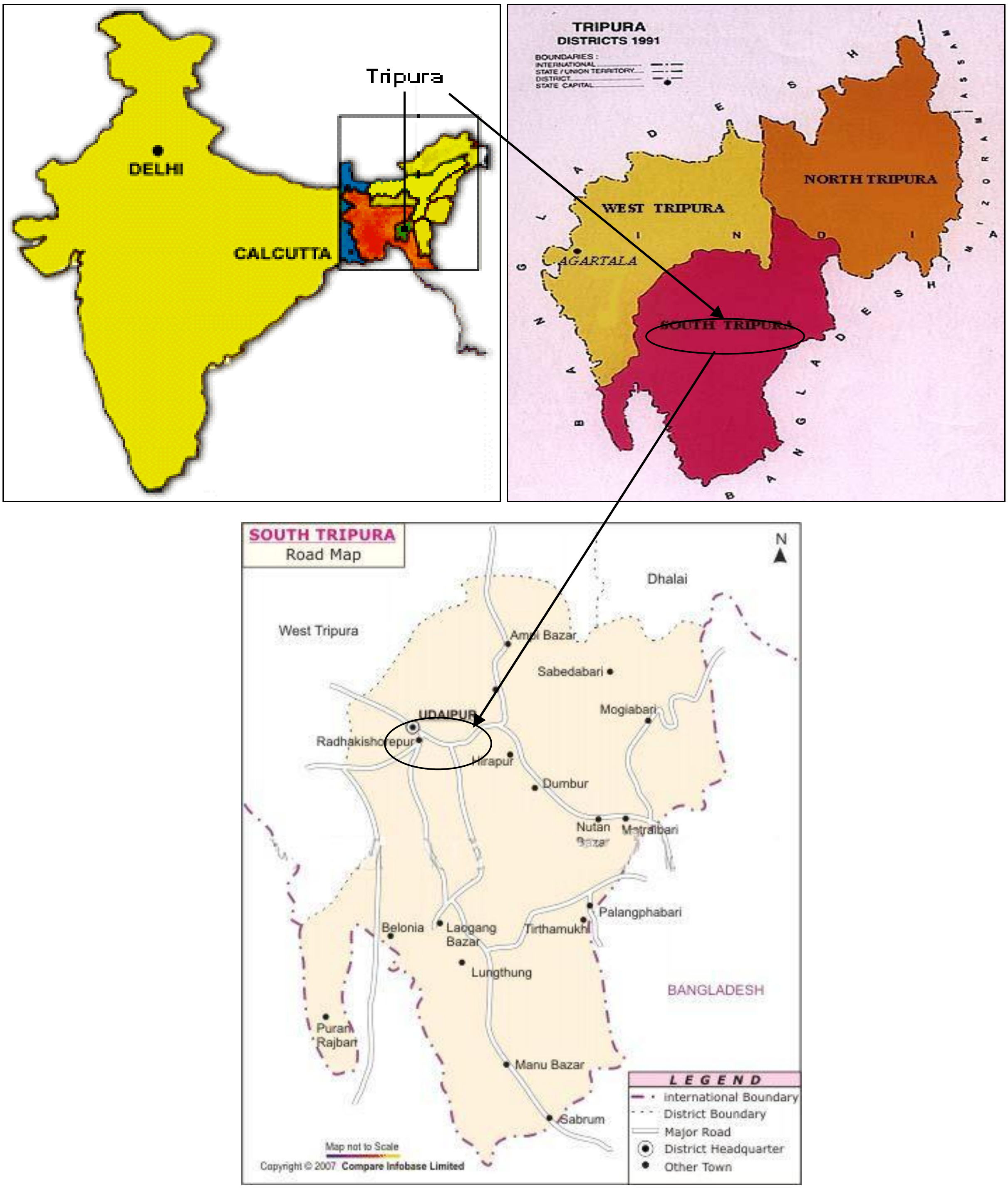
The plant will be located in Pallatana in Tripura. The details of the physical location of the plant are given below:

Plant location data

Village / City	Pallatana
Sub-Division	Udaipur (Head quarters is 9km from Plant site)
District	South Tripura
State	Tripura
Country	India
Latitude	23º 29’ 59.2” N
Longitude	91º 26’ 13.7” E
Power Station Site Elevation	24.3 m Above Mean Sea Level (MSL)
Nearest Railway Station	Manughat
Nearest Town	Udaipur
Road Approach	Udaipur-Kakaraban
Nearest Airport	Agartala (Domestic)
Nearest Seaport	Nearest seaport in Indian territory is Kolkata

The location map is also provided below:



Location map of the project

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

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The project activity is a large scale CDM project for Grid Connected Electricity Generation using Natural Gas. Therefore as per the 'List of sectoral scopes and related approved baseline and monitoring methodologies', the project activity may principally be categorized in:

Scope Number – 1
Sectoral Scope – Energy Industries (renewable/non-renewable sources).
Methodology – AM0029 - "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas" (Version 03)

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

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The proposed project is natural gas based CCGT power plant of gross generation capacity – 726.6 MW. The proposed power plant will consist of two power plant blocks, each with a Gross Rating of 363.3MW (232.39 MW Gas Turbine and 130.91 MW Steam Turbine Generator).

The basic process in generation of power through combined cycle power plant (CCPP) comprises firing of natural gas and using the higher pressure of the expanding hot gases to drive the gas turbine generator (GTG). A gas turbine operates on the thermodynamic principle of Brayton's cycle and is coupled with generator, which produces electricity. The exhaust gases from the gas turbine at a substantial temperature of more than 550 deg centigrade are fed into a Heat Recovery Steam Generator (HRSG), which produces steam. The steam is fed into a steam turbine which when coupled with generator produces electricity. A gas turbine when coupled with a steam turbine produces more electricity with the same quantity of fuel and hence CCPP has a higher efficiency as compared to the average coal fired rankine cycle based thermal power plant.

In order to maximize the efficiency of the machine and minimize the gas consumption, latest technology Advanced Class Machines (ACM) would be deployed for the power plant, which would comprise the latest Frame-IX (or equivalent) gas turbines.

There is no technology transfer involved in the project activity.

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 CO_2 e
1st Jan 2013-31st Dec 2013	1,612,506
1st Jan 2014-31st Dec 2014	1,612,506
1st Jan 2015-31st Dec 2015	1,612,506
1st Jan 2016-31st Dec 2016	1,612,506
1st Jan 2017-31st Dec 2017	1,612,506
1st Jan 2018-31st Dec 2018	1,612,506
1st Jan 2019-31st Dec 2019	1,612,506
1st Jan 2020-31st Dec 2020	1,612,506
1st Jan 2021-31st Dec 2021	1,612,506
1st Jan 2022-31st Dec 2022	1,612,506
Total estimated reductions (tonnes of CO_2e)	**16,125,060**
Total number of crediting years	**10**
Annual average over the crediting period of estimated reductions (tonnes of CO_2 e)	**1,612,506**

A.4.5. Public funding of the project activity:

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No public funding from parties included in Annex I is available to the project.

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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Title: Approved baseline methodology AM0029 (Version 03, 16th May 2008) "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas"

Reference:

- NM0153: "Baseline methodology for grid connected electricity generation plant using Natural gas (NG)/ Liquefied Natural Gas (LNG) as fuels".
- NM0080 (version 3): "Baseline methodology for grid connected electricity generation plant using non-renewable and less GHG intensive fuel"
- This methodology also uses the build margin (BM) and operating margin (OM) approach as specified in "Tool to calculate emission factor for an electricity system" and makes reference to the latest approved version of the "Tool for the demonstration and assessment of additionality".

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

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The approved baseline methodology AM0029 Version 03 is applicable to the project activity. This is justified using the applicability criteria of the methodology as under:

<table>
<tr><th>Applicability criteria</th><th>Justification</th></tr>
<tr><td>The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant</td><td>The project activity is a green-field natural gas fired grid-connected electricity generation plant. Hence this criterion is satisfied.</td></tr>
<tr><td>The geographical/physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available</td><td>The baseline grid is the NEWNE grid and its boundary can be clearly identified. The information pertaining to this grid has been made publicly available by the Central Electricity Authority, Ministry of Power, Government of India.</td></tr>
<tr><td>Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity</td><td>Oil and Natural Gas Corporation Ltd. (ONGC) is the principal supplier of natural gas in the region as well as for the proposed project. They had formed a multi disciplinary team (MDT) in February 2008 to establish the feasibility of augmenting the production of natural for supply to OTPC. The present customers of ONGC have a total demand of 1.78 MMSCMD as shown below:
<table>
<tr><th>Customer</th><th>Demand (MMSCMD)</th></tr>
<tr><td>NEEPCO RC Nagar</td><td>0.75</td></tr>
<tr><td>TSECL Rokhia</td><td>0.58</td></tr>
<tr><td>TSECL Baramura</td><td>0.4</td></tr>
<tr><td>TNGC City</td><td>0.025</td></tr>
</table></td></tr>
</table>

<table>
<tr><td></td><td>
<table>
<tr><td>TNGC Brick kiln</td><td>0.002</td></tr>
<tr><td>TNGC – IGC</td><td>0.016</td></tr>
</table>
In the future, NEEPCO Monarchak is expected to draw 0.5 MMSCMD gas from 2013-14 onwards. OTPC is envisaged to draw another 1.325 MMSCMD in 2011-12 and 2.65 MMSCMD from 2012-13 onwards. Hence, the total demand for natural gas is expected to be 4.93 MMSCMD in the future.
Considering this demand for natural gas, ONGC has taken the decision to augment its gas production potential to cater to the needs of different consumers in the state. They are expanding their gas handling facilities to a capacity of 7.5 MMSCMD in a phased manner. Thus, it can be concluded that natural gas will be sufficiently available in the region and future natural gas based power capacity additions will not constrained by the use of natural gas in the project activity.Natural gas is sufficiently available in the state of Tripura. OTPC has entered into a Gas Sale and Purchase Agreement with ONGC. A Long Term Gas Profile of the region provided by ONGC states that in the year 2011-12 when the project activity is expected to start operation, the total gas availability is likely to be 2,500 million cubic metres as against the annual gas requirement of 1,037 million cubic metres in the project. This total gas reserve is expected to increase upto 6,150 million cubic metres by 2031-32.Hence, future natural gas based power capacity additions, comparable in size to the project activity, would not be constrained by the use of natural gas in the project activity.
</td></tr>
</table>

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

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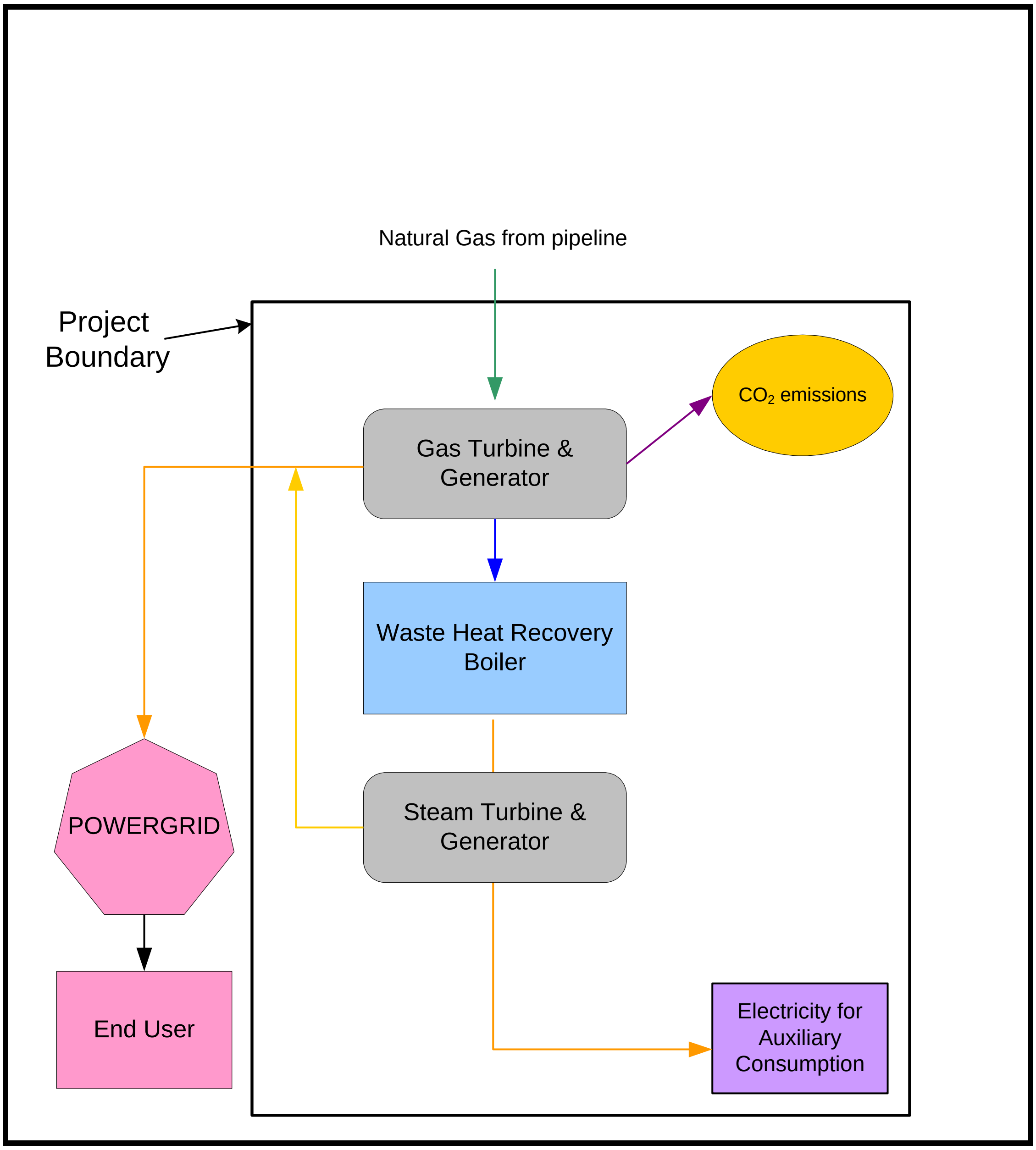
For the proposed project activity, the project boundary is from the point of fuel supply to the point of power export to the grid where the project proponent has full control. Thus, the project boundary covers gas supply and gas compression inside the plant boundary, boiler, gas and steam turbines and all other power generating equipment, captive consumption units and energy consuming equipment, since a part of the electricity generated will be used for auxiliary consumption. A Flow chart indicating the project boundary is illustrated in the diagram below:



Project boundary

As mentioned above, the spatial extent of the project boundary includes the project site and all the power plants connected physically to the baseline grid as defined in ACM0002.

In the calculation of project emissions, only CO_2 emissions from fossil fuel combustion at the project plant are considered. In the 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 below:

Overview of emission sources included or excluded from the project boundary

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

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

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The methodology is based on the approach of "Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment" and requires financial data of the project activity and its alternatives. As per the methodology, the various alternatives to the project activity are identified and analysed below:

The following paragraphs describe in a step by step manner how the methodology is applied in the context of the project activity.

Identification of baseline scenario for the project activity:

Baseline selection guideline as mentioned in the new methodology has been applied.

Step 1: Identification of alternatives to the project activity consistent with current laws and regulations

Sub-step 1a. Define alternatives to the project activity

It is required to identify realistic and credible alternative(s) that were available to project activity. These alternatives are required to be in compliance with all applicable legal and regulatory requirements.

The project developer identified plausible project options, which include all possible courses of actions that could be adopted in order to produce equivalent electricity for the end –users.

There are three plausible options available to meet the power requirement equivalent to the project activity.

Project Option 1 – Present Grid Mix (No project activity)

In this scenario the end user would get electricity from the current grid mix which consists of a mix of thermal (coal and diesel), hydro, nuclear and other renewable energy based power plants and an equivalent amount of carbon dioxide would be emitted at the generation end.

Project Option 2 – Power generation using Coal (fossil fuel) through sub-critical technology

In this scenario the project proponent would have set up a coal based power plant based on sub-critical technology of the closest comparable capacity i.e. 500 MW. Considering the fact that operating a coal based power plant would be the most economical option, this scenario is the most probable alternative available with the project proponent. With an increased thermal capacity addition of 500 MW, coal based power plant would have resulted in an increase in the amount of carbon dioxide generated by the regional grid mix for equivalent electricity.

Technical life time and efficiency coal based power plant (sub critical technology)

The coal based power plant have the technical life time of 25-30 years which is as CERC order dated 09/05/2002 and the average heat rate taken for coal based power plant is 2450 kcal/kWh for subcritical plants which is equivalent to efficiency of 35.1%.

Project Option 3 – Power generation using Coal (fossil fuel) through super-critical technology

In this scenario the project proponent would have set up a coal based power plant based on super-critical technology of the closest comparable capacity i.e. 500 MW. Considering the fact that operating a coal based power plant would be the most economical option, this scenario is the most probable alternative available with the project proponent. With an increased thermal capacity addition of 500 MW, coal based power plant would have resulted in an increase in the amount of carbon dioxide generated by the regional grid mix for equivalent electricity.

Technical life time and efficiency coal based power plant (super critical technology)

The coal based power plant have the technical life time of 25-30 years which is as CERC order dated 09/05/2002 and the average heat rate taken for coal based power plant is 2403 kcal/kWh for supercritical plants which is equivalent to efficiency of 35.79%.

Project Option 4 – Project activity not undertaken as CDM project activity

In this scenario the project proponent would set up the Natural Gas based power plant using Combined Cycle technology without revenue from CDM. This is a possible alternative, however it is not economically attractive for the project proponent.

Project Option 5 – Power generation using hydro power

a) Being dependent on the seasonal flow of water, the nature of operation of hydro power plants in India is mainly as peaking stations rather than base load stations. The methodology requires analysis of alternatives that deliver services similar to the project activity. The OTPC project activity has a plant load factor of 80% whereas hydro power plants generally have an average PLF of 38.1% (http://cea.nic.in/reports/yearly/hyd_perfm_review(summ)_rep/HPR(S)%2007-08.pdf). During lean seasons, when the flow of water is low, hydro power plants are unable to provide the optimum generation which can otherwise be expected from a natural gas power plant that operates consistently throughout the year.

Further the following run-of-the-river projects under implementation in the NEWNE grid also have low values of PLF when compared to the project activity:

- Teesta Stage-VI 500 MW Hydro Electric Project (PLF of 55.73%) (http://cdm.unfccc.int/UserManagement/FileStorage/GIKLRE8MNTXSZAY90F4312WBUVJ6CH)
- 1000 MW Hydroelectric Project by Jaypee Group in Himachal Pradesh (PLF of 50.93%) (http://cdm.unfccc.int/UserManagement/FileStorage/TIJ1RMX9WC5H2UGDPFZQ0EYVSANK3O)
- Teesta Stage – III 1200 MW (PLF of 49.31%) (http://cdm.unfccc.int/UserManagement/FileStorage/15LTVPS76FZKC9XBW8RJH2AY3DM0OQ)

Hydro power plants also face huge problems due to cost overruns, schedule slippages, silt content damaging machinery and damage from floods or loss of generation due to unreliable water flow.

The Tehri Dam in U.P. has been stopped several times, and after a lot of cost addition due to delays. In the state of Kerala, the development of hydro-power has almost come to a standstill due to the strong pressure of environmental lobby. (http://hydropowerstation.com/?tag=hydel-power-projects)

Therefore hydro power plants cannot be considered as viable baseline alternatives to the project activity that faces none of the aforementioned problems..

Project Option 6 – Power generation using wind energy

Wind energy based power generation projects do not qualify for "base-load firm power" because wind power projects are not subject to the dispatch rules like the coal or gas based projects and hence cannot be compared with the proposed project activity in terms of the services that it delivers. Hence this option has been excluded as a baseline scenario.

Project Option 7 – Power generation using nuclear power

The nuclear energy based power generation in India does not fall in the purview of Central Electricity Regulatory Commission (“CERC”) and the State Electricity Regulatory Commissions (“SERC”) and the tariff is unilaterally decided by Nuclear Power Corp. Ltd. Further, this option is not available to a private investor and hence has been excluded as a baseline option.

Project Option 8 – Power generation using diesel/naptha

The highest capacity power plant running on diesel in India is 106.5 MW (Brahmapuram DG), which is not comparable to project activity scale. Also, diesel based power generation is typically used as a peak load station.

With increase in global Naphtha prices and prevailing price differential between export price and domestic price, Naphtha is a predominantly exported commodity and India is a net exporter of Naphtha[2].

Total installed capacity of Naphtha based generation capacity installed in India is 1,822 MW[3] and no Naphtha based generation capacity has been added in India since 2000-01 due to high operational costs. Majority of naphtha based generation capacity commissioned in India is of older generation.

Considering above mentioned constraints with respect to delivery of output & services and fuels used, this alternative is not considered further for arriving at the baseline scenario.

Project Option 9 – Power generation using natural gas as fuel and open cycle technology

The turbine’s energy conversion efficiency typically remains low (@35%-42%[4]) when utilized as an Open (simple) cycle. This very low efficiency makes open cycle gas turbine based power generation less attractive as compared to a combined cycle gas turbine based power generation. Consequently, this option is not a plausible baseline scenario and has not been discussed any further in the PDD.

From the above assessment we may conclude that the project activity has three other project options available

Project Option 2 – Power generation using Coal (fossil fuel) through sub-critical technology
Project Option 3 – Power generation using Coal (fossil fuel) through super-critical technology
Project Option 4 – Project activity not undertaken as CDM project activity.

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[2] Source: Page 16, http://petroleum.nic.in/petstat.pdf

[3] Source: Baseline Carbon Dioxide Emission Database Version 3.0 – LATEST http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

[4] http://www.etsap.org/E-techDS/PDF/E02-gas_fired_power-GS-AD-gct.pdf Page 4

Step 2: Identification of the economically most attractive baseline scenario alternative

Detailed financial analysis of the identified feasible alternatives has been carried out. The methodology prescribes to use investment analysis to identify the economically most attractive baseline scenario alternative. The Project IRR (%) of the alternatives are calculated and used as the financial indicators for comparison in the investment analysis. Detailed financial analysis of the identified feasible alternatives i.e. generation of power using coal has been carried out in a transparent manner and is given below.

	Project cost	**Source**
Gas based Power Plant	23588.7 Millions	Cost of the project plant – Cost of the project plant (23588.7 INR Millions))has been taken from the Detailed project report(DPR) dated October 2005 , the same has been cross checked with the 23rd Meeting of Board of Directors on 18.12.2008 estimated the project cost to be 34,290, INR Millions hence deemed conservative for the analysis of financial calculations
Subcritical Power Plant	40 INR Million/MW	Cost has been taken from the Report of the Expert Committee on Fuels for Power Generation Appendix I the same is cross checked with registered CDM project (Regn. No.4334) which indicates that the cost of sub critical is 40 INRMillion/MW in the project case it is taken as 40 INR Million/MW hence stands justified for comparison of IRR.
Super critical power plant	45.3 INR Million/MW	The cost of the project can also cross checked with another registered CDM project (Regn. No.2915) and which indicates that the cost of super critical is 45.3 INR million/MW), in the project case it is taken as 45.3 INR Million/MW hence stands justified

Assumptions	Gas based Power Plant		Source	Coal based Power Plant		Source
Heat Rate	1850	kcal/kWh	Detailed Project Report(DPR)	2,450 Sub-critical	kcal/ kWh	CERC Tariff Order dated 26 March 2004
				2,403 Super-critical	kcal/ kWh	
Calorific Value	9100	kcal/ m^3	Detailed Project Report(DPR)	5,400	kcal/kg	CEA expert committee report 2004
Price	2.5	USD/MMBTU	Detailed Project Report(DPR)	538	per kg	Report of the Expert Committee on Fuels for Power Generation Appendix I
Capacity of plant	726.6	MW	Detailed Project Report(DPR)	1000	MW	Technical specifications
Increase in O&M cost	0.608	Million pa per MW	DPR	4.0%	per year	CERC Tariff Order dated 26 March 2004
Interest on INR loans	9%	pa	DPR	9%	pa	Same as project activity
Depreciation						
Depreciation rate(SLM)	5.46%	pa	Detailed Project report(DPR)	3.60%	pa	http://www.cercind.gov.in/070104/appendix_2.doc
Plant & Machinery	15%	pa	As per IT Act	15%	pa	As per IT Act
Civil Works	10%	pa	As per IT Act	10%	pa	As per IT Act
Auxiliary consumption	26.6	MW	Detailed Project report(DPR)	9%	%	CERC Tariff Order dated 26 March 2004
Plant Load factor	80	%	Detailed Project report(DPR)	80	%	CERC Tariff Order dated 26 March 2004

Parameter	Gas	Coal - subcritical	Coal - supercritical
Project IRR	9.85%	10.92%	10.87%

The project activity without considering CDM revenues has the lowest project IRR among the alternatives.

The ***option 2***: *“Power generation using Coal (fossil fuel) through sub-critical technology”* has the highest project IRR among all the alternatives. Therefore, it may be concluded that ***option 2***: *“Power generation using Coal (fossil fuel) through sub-critical technology”* is the economically most attractive baseline scenario.

Key parameters of the project activity:

Considering the guidelines of the methodology in view of the site/location- specific conditions of project activity, following are the key parameters and assumptions considered for the project activity which will affect the emission reductions.

- Estimation of present and future generation mix (grid/private supplier)
- IPCC CO_2 Emission Factors
- Cycle efficiency of the system
- Government policies/guidelines for Independent Power Producers (IPP’s)
- As per the Electricity Act 2003, the projects, which have the lowest tariff, will be the preferred ones. Since the cost of power generation with coal as fuel is the lowest, most of the new projects will be set up with coal as fuel

The above parameters /assumptions are appropriately studied and considered for estimation of the emission reduction.

Estimation of Baseline CO_2 emission factor ($EF_{BL,CO2,y}$):

Considering the project situation, formulae are selected from the methodology and applied for estimation of emission reductions by project activity. Further, as suggested in the methodology, emission factor estimation has been carried out using following three methods.

Option 1: The build margin, calculated according to ACM0002; and
Option 2: The combined margin, calculated according to ACM0002, using a 50/50 OM/BM weight.
Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under “Identification of the baseline scenario” above,

S. No.	Option	Value
1	Option 1: The build margin, calculated according to ACM0002	675.2 tCO_2/GWh
2	Option 2: The combined margin, calculated according to ACM0002, using a 50/50 OM/BM weight	840.9 tCO_2/GWh
3	Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under “Identification of the baseline scenario	994.3 tCO_2/GWh

As the BM factor of current generation mix is lower than the other two options, it has been selected as baseline emission factor on conservative basis.

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):

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As per the "*Guidance on the demonstration and assessment of prior consideration of the CDM"* Version 03, for project activities with start date before 02 August 2008, the project participant is required to demonstrate that the CDM was seriously considered in the decision to implement the project activity. This has been demonstrated as below:

(a) The minutes of meeting of the Board of Directors of OTPC dated 06/02/2006 clearly show that the benefits of the CDM were considered in the decision to implement the project activity. This demonstrates awareness of the CDM prior to project activity start date.

(b) The project participant took continuing and real actions to secure CDM status for the project activity in parallel with its implementation and at no point of time has the interval between these events exceeded two years. This is demonstrated through a timeline of events and actions taken for CDM registration and project implementation provided below:

Event	Date	Reference
Incorporation of OTPC as an SPV for implementation of project activity	27-Sep-04	Ref. No. U40101TR2004PLC007544 dated 27/09/2004
Appointment of CDM consultant	18-Oct-05	Engagement Letter dated 18.10.2005
Preparation of Detailed Project Report	Oct-2005	DPR prepared by Fichtner Consulting Engineers (India) Pvt. Ltd.
Certificate of Incorporation consequent on Change of name	20-Dec-05	Certificate Ref. No. STA/02-07544/Section 21/3788 dated 20/12/2005
Resolution by Board of Directors to implement the project activity considering CDM benefits	06-Feb-06	Minutes of Board Meeting dated 06/02/2006
Clearance from Ministry of Environment & Forests for diversion of forest land	25-Apr-06	F. No. 8-60/2005-FC dated 25/04/2006
Finalization of EIA Report for Project Activity	Mar-06	EIA Study carried out by Ghosh, Bose & Associated Pvt. Ltd.
Public Hearing for invitation of comments from Local Stakeholders (for environmental clearance)	19-May-06	Minutes of Public Hearing dated 19/05/2006
Quotations from DOE for validation of project activity	27-Jun-07	Minutes of 17th Board Meeting held on 27/06/2007
Receipt of Host Country Approval from National CDM Authority (MoEF)	06-Jul-07	F. No. 4/2/2007-CCC dated 06/07/2007
Appointment of DOE for validation of project activity	29-Aug-07	Engagement letter with DNV

PDD revised according to new version of methodology AM0029 Version 2	2-Nov-07	http://cdm.unfccc.int/methodologies/DB/WW4I82DG7LJUQE5E5YGT1NZE4PNS60/view.html
MoU with NBCC for boundary wall construction	16-Jan-08	MoU with NBCC Ref. No. 194766 dated 16.01.2008
PDD revised according to new version of methodology AM0029 Version 3	30-May-08	http://cdm.unfccc.int/methodologies/DB/WW4I82DG7LJUQE5E5YGT1NZE4PNS60/view.html
Notice of Award to BHEL (NoA)	23-Jun-08	OTPC Letter Ref. No. OTPC/EPC/GEN/2008
Resolution for changes in Project Boundry (project to not include transmission component)	23-Jun-08	Minutes of 21st Board Meeting held on 23/06/2008
Execution of Supply and Services Contract between OTPC and BHEL	11-Aug-08	Contract Ref. No. OTPC/EPC/GEN/002
Signing of Gas sale and Purchase agreement with ONGC	29-Sep-08	Agreement Ref. No. M479685 dated 29/09/2008
Certificate of Incorporation consequent on Change of name on conversion from Private Limited to Public Limited Company	30-Dec-08	Ref. No. U40101TR2004PLC007544 dated 30/12/2008
Amendment of Engagement with CDM consultant	9-Jun-09	Amendment Letter dated 09.06.2009 with CDM consultant
PDD published for Global Stakeholder Consultation Process	28 Apr 10 - 27 May 10	http://cdm.unfccc.int/Projects/Validation/DB/1PI7WNZZJO04NEOQ8N0VRKFR1KMN79/view.html
Receipt of revised Host Country Approval from National CDM Authority (MoEF)	12-Jul-10	F. No. 4/2/2007-CCC dated 12/07/2010

Thus as demonstrated above in accordance with "*Guidelines on the demonstration and assessment of Prior Consideration of the CDM*" Version 3, CDM was seriously considered in the decision to implement the project activity.

As per the selected methodology, the project proponent is required to establish that the GHG reductions due to project activity are additional to those that would have occurred in absence of the project activity as per the 'Tool for the demonstration and assessment of additionality' Version 05.2. Additionality of project activity is discussed further. As per the methodology the project's additionality has been proved using the following three steps.

Step 1 – Benchmark Investment Analysis:

OTPC has conducted an investment analysis of the project activity with Project Internal Rate of Return (IRR) as the financial indicator and Weighted Average Cost of Capital (WACC) as the benchmark.

'Internal Rate of Return' is one of the known financial indicators used by banks, financial institutions and project developers for making investment decisions. Weighted Average Cost of Capital (WACC) is an appropriate benchmark for Project IRR as per the "Guidance on the

Assessment of Investment analysis", (EB 51, Annex 58) Paragraph 12 which states "*Local commercial lending rates or weighted average costs of capital (WACC) are appropriate benchmarks for a project IRR*".

Benchmark Analysis

WACC methodology is a widely accepted parameter for calculating the cost of capital. It has been calculated by taking the respective proportion of debt and equity in the financing pattern as weights. The benchmark for the project has been derived based on the cost of equity financing representing the required return on capital by investors and the cost of debt financing representing required rate of return on capital by the creditors as illustrated below:

$$WACC = [D/(D+E)] \times [Cost\,of\ Debt] \times [1 - T_c/100] + [E/(D+E)] \times [Cost\,of\ Equity]$$

Where,

D = Debt component of total investment
E = Equity component of total investment
T_c= Corporate tax rate

The project proponent has identified the *Government bond rates, increased by a suitable risk premium to reflect private investment and/or the project type* [paragraph 6(a) of sub-step 2b)] as the **cost of equity** and *Prime lending rate* prevailing at the time of investment decision as the **cost of debt**. The same has been adjusted to tax rate in order to serve as a benchmark comparable to post tax IRR computations.

"Guidance on the Assessment of Investment Analysis" (EB 51, Annex 58), paragraph 13, states, "*In the cases of projects which could be developed by an entity other than the project participant, the benchmark should be based on publicly available data sources which can be clearly validated by the DOE. Such data sources may include local lending and borrowing rates, equity indices, or benchmarks determined by relevant national authorities".* In accordance with this guidance, the benchmark WACC has been calculated taking values from publically available data sources, namely the websites of Reserve Bank of India, Bombay Stock Exchange and Bloomberg. Cost of equity has been calculated based on historical market returns of BSE 500, Beta values for the sector have been referred from Bloomberg, and Interest Rates on Central and State Government Dated Securities have been referred from Reserve bank of India records. Cost of debt has been taken as the Prime Lending rate prevailing at the time of investment decision making as was quoted by RBI. Thus, all the data sources utilized for benchmark computation are publically available and can easily be validated by the DOE.

<u>*Cost of equity*</u>

The Capital Asset Pricing Model (CAPM) approach having a clear theoretical foundation is a widely used methodology for determining the cost of equity and has come to dominate modern financial theory[5]. It asserts that the required rate of return on a risky asset is a function of the risk free rate of return (R_f) plus a risk premium that reflects the return on a well-diversified portfolio of risky assets over the risk free rate ($R_m - R_f$), scaled by the "beta" of the risky asset which is a measure of the systematic risk of the risky asset relative to the market risk as shown below.

$$R_e = R_f + B \times (R_m - R_f)$$

Where:

[5] http://en.wikipedia.org/wiki/Capital_asset_pricing_model

R_e = Rate of return on equity capital
R_f = Risk-free rate of return
B = Beta
R_m-R_f = Market risk premium

The risk-free rate is the interest rate that is assumed and can be obtained by investing in financial instruments with no default risk. The volume weighted average yield on central Government Securities has been taken to represent the risk free return. The risk free rate of return for the year 2005-06 has been considered and is taken as 6.11%

BSE 500 Stock Index has been used to represent the market return. The BSE 500 is a widely used market index in India and Asia. It represents nearly 93% of the total market capitalization on the Bombay Stock Exchange and covers all 20 major industries of the economy. The index was christened on 09 August 1999 with 500 scrips keeping in mind the changing pattern of the economy and that of the market. Prior to investment decision, the historical returns generated by BSE 500 were studied and were found to be 21.94%.

"Guidance on the Assessment of Investment Analysis" (EB 51, Annex 58), paragraph 14, states, "*Risk premiums applied in the determination of required returns on equity shall reflect the risk profile of the project activity being assessed, established according to national/international accounting principles. It is not considered reasonable to apply the rate general stock market returns as a risk premium for project activities that face a different risk profile than an investment in such indices*". In line with this guidance, the risk of the project activity sector has been incorporated in the calculation of risk premium using a Beta value (B) appropriate to the project activity. This beta, accounts for systematic risk by quantifying the sensitivity of the stocks of the companies representing a particular project type/sector with the market portfolio and incorporates the risk of a specific sector in the calculation of the risk premium.

Beta describes how the expected return of a stock is correlated to the return of the financial market and reflects the sensitivity of the company to market risk factors. For companies that are not listed, beta values of publically traded firms whose operations and risk profiles are as similar as possible to the project activity can be considered and used as a measure of the project activity's systematic risk. Therefore, beta values of the listed private companies engaged in similar business as the project activity (i.e. the power sector) at the start of the project activity estimated by regressing returns on stock against local index, using 5 years of data have been utilized. The table below summarizes the equity beta values:

Company Name	**Equity Beta**
CESC Ltd.	0.978
GUJARAT INDS POWER CO LTD	1.360
NTPC	0.953
TATA POWER CO	1.242
Reliance Infra	0.931
Neyveli Lignite Corporation	1.360
Average	**1.1373**

Source: Bloomberg

The measured equity beta for a particular firm relates to the unique capital structure of that firm and that a change in the capital structure will change the degree of financial risk borne by the equity holders and hence the equity beta. Since financial leverage can vary across industries, countries and firms, and, furthermore, financial leverage is a determinant of beta, it is common to de-lever (i.e. stripping out the gearing component) comparable betas to arrive at an un-levered beta then to re-lever at the target financial leverage considered appropriate for the business in question. The asset beta (which is the equity beta that would apply if the assets were financed entirely with equity) is obtained with the following formula:

Modigliani - Miller Formula: $\beta_{asset} = \dfrac{\beta_{equity}}{\left(1+(1-t)\cdot\dfrac{D}{E}\right)}$

Where β_{asset} corresponds to the un-levered β and the β_{equity} to the levered β.

The following table illustrates the asset beta values of the companies estimated using the above formula:

Company Name	Asset Beta
CESC Ltd.	0.43
GUJARAT INDS POWER CO LTD	0.47
NTPC	0.70
TATA POWER CO	0.84
Reliance Infra	0.58
Neyveli Lignite Corporation	1.22
Average	**0.7071**

The average asset beta of companies engaged in power sector is thus 0.7071 and the same has been used to estimate the benchmark cost of equity. Since the un-levered or asset beta is the least and most conservative beta (as opposed to re-levered beta and equity beta), the same has been chosen as a conservative estimate of the risk for the power sector.

Cost of Debt

Cost of debt is defined as the rate at which lender's agree to lend money to a project. The 'Guidance on the Assessment of Investment Analysis' clarifies that, '*In the cases of projects which could be developed by an entity other than the project participant, the benchmark should be based on publicly available data sources which can be clearly validated by the DOE. Such data sources may include local lending and borrowing rates, equity indices, or benchmarks determined by relevant national authorities.'*

Accordingly, the Prime Lending Rate (PLR) quoted by the RBI at the time of decision making is identified as the appropriate yardstick. The PLR was found to range between 10.25 - 10.75%[6] and the average of this range (10.50%) has been taken as the cost of debt, while computing the WACC.

Weighted Average Cost of Capital (WACC)

Market Risk Premium = R_m - R_f
= 21.94% - 6.11%
= 15.83%

Rate of return on equity (R_i) = R_f + β (R_m-R_f)
= 6.11% + 0.71 x 15.83%
= 11.72%

The benchmark rate of return (WACC) for the project activity thus works out to 11.72%. This is the minimum rate of return the project can be expected to generate to be seen as an attractive investment opportunity for the project proponent.

[6] http://rbidocs.rbi.org.in/rdocs/Wss/PDFs/67044.pdf

Calculation and comparison of financial indicators

The IRR analysis has been carried out in accordance with the "Guidance on the Assessment of Investment Analysis" (EB 41, Annex 45) Paragraph 3, which states that for carrying out IRR analysis, "*Both project IRR and equity IRR calculations shall as a preference reflect the period of expected operation of the underlying project activity (technical lifetime), or - if a shorter period is chosen - include the fair value of the project activity assets at the end of the assessment period. In general a minimum period of 10 years and a maximum of 20 years will be appropriate*."

The project IRR is computed for a period of 15 years. The period has also been selected based on the typical life time of gas based power plants as per the Central Electricity Regulatory Commission (CERC).

The following assumptions have been taken for IRR computation:

Assumptions			
Parameter	**Units**	**Value**	**Source**
Project Cost	INR Lakhs	235,887	Volume II DPR
Debt:Equity Ratio	-	2.33	
Percentage of Debt	%	70%	
Percentage of Equity	%	30%	

Operational Parameters			
Plant Load Factor (PLF)	%	80%	Volume II DPR
Auxiliary Power Consumption	MW	26.6	
Gross Heat Rate	kCal/kWh	1850	
Calorific Value of Natural Gas	kCal/Sm3	9100	
Conversion rate between USD and INR	INR/USD	45	
Transmission Service Charges	INR/kWh	0.29	
Cost of fuel	USD/MMBTU	2.5	Volume I DPR
Escalation in Cost of Fuel	%	4%	
Cost of Fuel as on COD	INR/Sm3	4.570	Calculated

Term Loan			
Amount of Debt	INR Lakhs	165,121	Volume II DPR
Interest on Debt	% pa	9%	
Repayment Period	years	10	
Moratorium	years	0.5	

Depreciation			
Companies Act			
Residual value (except land)	%	10%	Volume II DPR
Depreciation Rate	%	5.46%	
IT Act			
Plant & Machinery	%	15%	As per IT Act
Civil Works	%	10%	

Return on Equity	%	14%	CERC Tariff Order
Levellised Tariff (15 Years)	INR	2.02	The tariff used in the financial of the project

			activity is the function of various input parameters, values of which have been taken from the DPR and levelised tariff has been calculated based on those parameters.
Discount Factor for Levellised tariff	%	6.19%	http://www.cercind.gov.in/08022007/Notification_dated_20.9.2005.pdf

Working Capital			
Maintenance and Spares	% Project Cost	1%	Volume II DPR
Escalation in Maintenance & Spares	%	6%	
Receivables for	months	2	
O&M expenses	months	1	
Fuel costs	months	1	
Interest on Working Capital	%	10.25%	

Operation & Maintenance			
Operation & Maintenance	million pa/MW	0.608	Volume II DPR
Escalation in O&M	%	4%	

Taxation			
Corporate Tax Rate	%	33.66%	Volume II DPR
MAT Rate	%	7.84%	

Using the assumptions in the table above, the post-tax project IRR for the project activity works out to be 9.85% which is considerably lower than the benchmark rate of 11.72% adopted by the project. Thus the proposed project activity is not a financially attractive alternative since the returns are lower than the benchmark rate of return expected from the project activity.

Sensitivity analysis:

The project activity was found to be sensitive to the following factors –

1. Change in PLF
2. Change in capital cost
3. Change in O&M cost
4. Change in fuel price

The sensitivity analysis was conducted for scenarios with variations in each one of the above-mentioned factors and for scenarios with variations in all the above-mentioned factors simultaneously in order to assess the financial attractiveness of the project activity under such circumstances.

Sensitivity analysis has been carried out considering variations in PLF, tariff rate, O&M cost, and project cost. In accordance with Paragraph 21 of the guidance, a range of +10% to -10% has been considered as the range of variation.

Upon introducing the variation of 10% in crucial parameters the IRR does not surpass the benchmark. The results of sensitivity analysis for the project activity are as given below:

S. No.	Parameters	Variation	IRR without CDM
1.	PLF	+ 10 %	9.90
		- 10 %	9.79
2.	Fuel cost	+10 %	9.90
		-10 %	9.79
3.	O&M Cost	+10%	9.85
		-10 %	9.84
4.	Project Cost	+10%	9.80
		-10 %	9.90

It is evident from the above that the IRR without CDM benefits is consistently below the benchmark of 11.72 %, even after introducing variation of 10% in the critical parameters.

There is significant risk associated with the project activity that impacts the viability of the project as highlighted through the sensitivity analysis. Hence, it can be justifiably concluded that CDM revenue, that the project activity would obtain through sale of the emission reductions, would lead to a significant increase in the project IRR (IRR for the project with CDM revenue increases to 15.07%), which alleviates the identified benchmark.

As no deviation was observed in IRR with +/- 10% variation in critical parameters, analysis was carried out to understand how much variation is required in each of critical parameter to make project IRR cross benchmark.

S. No.	Parameters	Variation required for IRR to reach benchmark	Comments
The financial internal rate of return of the project activity without CDM revenues			
1.	PLF	363%	The PLF value of 80% has thus been sourced from the Detailed Project Report prepared by a reputed third party engineering consultancy, FICHTNER Consulting Engineers (India) Pvt. Ltd., Chennai, India. A deviation of 360% in this value would be required to reach the benchmark which is physically not possible.
2.	Capital cost	-90%	Considering the inflation in the economy and the rising prices of steel and cement, a decrease of 89% in the capital cost is an unlikely scenario.
3.	O&M Cost	3870%	The O&M cost have been estimated from the Detailed Project Report. An increase of

			3850% in the same is not feasible.
4.	Fuel Price	363%	The project activity has an assured availability of natural gas from ONGC and has entered into a contract for the same that explicitly mentions the price of natural gas and its escalation. Hence, an increase of 360% in the base price of natural gas is not a likely scenario.

The results of the sensitivity analysis conducted confirm that the returns of the project activity without CDM revenues is much lower than the benchmark for the project activity, under circumstances which could bring about variations in the critical factors used for the IRR computations.

The above facts and figures clarifies that the '**project activity is financially non viable**' even with reasonable variations in the critical assumptions and hence CDM revenue is very crucial to sustain the operations of the project activity.

Step 2 – Common Practice Analysis

The project activity is the first-of-its kind in the North Eastern region of the country. The Central Electricity Authority, Ministry of Power has certified that the project is the first mega power project (> 700 MW) in North Eastern India. Mega power projects have not been developed in the region mainly due to the problem of logistics. North Eastern India has a difficult mountainous terrain which when coupled with the underdeveloped status of infrastructure of the region further aggravates the issue.

In the similar project sector, socio-economic environment, geographic conditions and technological circumstances the proposed project activity uses an energy efficient technology with higher costs, which has limited penetration. The unique technological features in the project activity are mentioned below:

- For efficient utilization of natural gas, it is envisaged that power blocks will not be operated in simple cycle mode. Instead the technology employed will be modern Combined Cycle Gas Turbine (CCGT) Technology and the proposed CCGT power plant will operate on Bryaton Cycle at top and Rankine Cycle at bottom.
- OTPC is implementing the proposed natural gas based CCPP in India with installation of the latest proven advanced class heavy duty gas turbine, each of which will comprise of a multistage axial compressors and a turbine including combustors section which will have an efficiency of 55% as against the existing natural gas based CCPP efficiency of around 49% in India[7].
- The gas turbine units will have Dry Low NO_x (DLN) combustors suitable for burning natural gas only.
- The Heat Recovery Steam Generators (HRSG) will have the dry run capability in order to reduce the black-start power consumption.
- In each HRSG, a condensate pre-heater (CPH) has been envisaged to recover the thermal energy of the hot gas to the maximum extent.
- Vent condenser would be provided with the Deaerator to minimise wastage of steam.

[7] Source: Research paper published by Hamburg Institute of International Economics (HWWI) | 2005 on CO2 emission reduction potential of large-scale energy efficiency measures in power generation from fossil fuels in China, India, Brazil, Indonesia and South Africa.
http://www.hwwi.org/publikationen/Dateien/HWWI_Research_Paper_5.pdf

- Logistics is a critical issue in case of the project activity, as the plant is coming up in difficult mountainous terrain of North Eastern India. The underdeveloped status of infrastructure of the region further aggravates the issue. In order to address issues related to logistics arrangements for the project, OTPC had appointed a leading logistics & transportation firm, to prepare a detailed feasibility report and equipment transportation plan for the project taking into consideration the weight and size of generation equipments. Based on the recommendations, OTPC has finalized use of a combination of waterways and roadways for shipment of heavy equipment & machinery to the plant site. To overcome the transportation hurdle the project promoter is considering development of a jetty at Karimganj (lower Assam) for transportation of plant equipment. Further to enable transportation of equipment through road (Karimganj onwards), of strengthening of National Highway no. 44 is being undertaken to widen the curves and improve turning radius. Also construction of bypasses for weak bridges and storage & parking areas along transportation route would be undertaken. However, the plans are yet to be finalized as of date.

However, considering the paragraph one of guidelines on common practice (Annex 12, EB 63) host country India has been selected as the applicable geographical area for the demonstration of the fact that the project activity is not a common practice scenario in the entire India.

Following steps demonstrate stepwise approach used for common practice as per guidelines on common practice (Annex 12, EB 63)

Step 1: Project design capacity is 726.6 MW. As per guidelines on common practice (Annex 12, EB 63)

applicable output range is +/- 50% of the design output or capacity of the proposed project activity . Therfore for the proposed project activity applicable output range is 363.3 MW to 1089.9 MW.

Step 2: Guidelines on common practice (Annex 12, EB 63) recommends identification of all plants in the applicable geographical area that that deliver the same output or capacity, within the applicable output range calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project. Hence, all plants in the applicable geographical area (India) that deliver the same output or capacity, within the applicable output range (363.3 MW to 1089.9 MW) calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project (23/06/2008) are as follows[8]

S_NO	NAME	DT_ COMM o last unit	CAPACITY MW AS ON 11/08/2008	STATE	SECTOR	SYSTEM	TYPE	FUEL 1
1	PATRATU	2-Mar-86	770	JHARKHAND	STATE	JSEB	THERMAL	COAL
2	TENUGHAT	10-Oct-96	420	JHARKHAND	STATE	TVNL	THERMAL	COAL
3	JOJBERA	23-Sep-05	427.5	JHARKHAND	PVT	TATA PCL	THERMAL	COAL
4	CHANDRAPURA	29-Mar-79	750	JHARKHAND	CENTER	DVC	THERMAL	COAL
5	BOKARO B	31-Mar-93	630	JHARKHAND	CENTER	DVC	THERMAL	COAL
6	TALCHER	24-Oct-83	470	ORISSA	CENTER	NTPC	THERMAL	COAL
7	I.B.VALLEY	22-Oct-95	420	ORISSA	STATE	OPGC	THERMAL	COAL

[8] Source: CEA - CO_2 Baseline Database Version 6.0, http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm

8	BANDEL	8-Oct-82	450	WEST BENGAL	STATE	WBPDC	THERMAL	COAL
9	SANTALDIH	7-Nov-07	730	WEST BENGAL	STATE	WBPDC	THERMAL	COAL
10	BAKRESWAR	23-Dec-07	840	WEST BENGAL	STATE	WBPDC	THERMAL	COAL
11	D.P.L.	24-Nov-07	690	WEST BENGAL	STATE	DPL	THERMAL	COAL
12	BUDGE BUDGE	6-Mar-99	500	WEST BENGAL	PVT	CESC	THERMAL	COAL
13	BALIMELA	27-Mar-08	510	ORISSA	STATE	OHPC	HYDRO	
14	UPPAR INDRAVATI	30-Mar-01	600	ORISSA	STATE	OHPC	HYDRO	
15	TEESTA -V	28-Mar-08	510	SIKKIM	CENTER	NHPC	HYDRO	
16	SAGARDIGHI TPP	20-Jul-08	600	WEST BENGAL	STATE	WBPDC	THERMAL	COAL
17	PURULIA PSS	23-Nov-07	900	WEST BENGAL	STATE	WBSEDCL	HYDRO	
18	RANGANADI	29-Mar-02	405	ARUNACHAL	CENTER	NEEPCO	HYDRO	
19	BADARPUR	25-Dec-81	705	DELHI	CENTER	NTPC	THERMAL	COAL
20	F_BAD CCGT	31-Jul-00	431.59	HARYANA	CENTER	NTPC	THERMAL	GAS
21	GNDTP(BHATINDA)	31-Jan-79	440	PUNJAB	STATE	PSEB	THERMAL	COAL
22	GHTP (LEH.MOH.)	31-Jul-08	920	PUNJAB	STATE	PSEB	THERMAL	COAL
23	N.A.P.S	5-Jan-92	440	UTTAR PRADESH	CENTER	NPC	NUCLEAR	NUCLEAR
24	R.A.P.S.	17-Nov-00	1180	RAJASTHAN	CENTER	NPC	NUCLEAR	NUCLEAR
25	ANTA GT	5-Mar-90	419.33	RAJASTHAN	CENTER	NTPC	THERMAL	GAS
26	PARICHA	28-Dec-06	640	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL
27	UNCHAHAR	28-Sep-06	1050	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL
28	TANDA	20-Feb-98	440	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL
29	AURAIYA GT	12-Jun-90	663.36	UTTAR PRADESH	CENTER	NTPC	THERMAL	GAS
30	DADRI GT	26-Feb-94	829.78	UTTAR PRADESH	CENTER	NTPC	THERMAL	GAS
31	DEHAR	10-Nov-83	990	HIMACHAL	CENTER	BBMB	HYDRO	
32	PONG	25-Feb-83	396	HIMACHAL	CENTER	BBMB	HYDRO	
33	SALAL I & II	23-Feb-95	690	JAMMU & KASHMIR	CENTER	NHPC	HYDRO	
34	CHAMERA-I	22-Apr-94	540	HIMACHAL	CENTER	NHPC	HYDRO	
35	URI	31-Mar-97	480	JAMMU & KASHMIR	CENTER	NHPC	HYDRO	
36	RANJIT SAGAR	12-Oct-00	600	PUNJAB	STATE	PSEB	HYDRO	
37	MANERI BHALI	10-Mar-08	394	UTTARAKHAND	STATE	UJVNL	HYDRO	
38	VISHNU PRAYAG	30-Sep-06	400	UTTARAKHAND	PVT	JVNL	HYDRO	
39	DULHASTI	26-Mar-07	390	JAMMU & KASHMIR	CENTER	NHPC	HYDRO	
40	TEHRI ST -1	19-Mar-07	1000	UTTARAKHAND	CENTER	THDC	HYDRO	
41	YAMUNANAGAR TPP	13-Nov-07	600	HARYANA	STATE	HPGCL	THERMAL	COAL
42	UKAI_Coal	30-Jan-85	850	GUJARAT	STATE	GSECL	THERMAL	COAL
43	GANDHI NAGAR	17-Mar-98	870	GUJARAT	STATE	GSECL	THERMAL	COAL
44	ESSAR GT IMP.	10-Aug-95	515	GUJARAT	PVT	ESSAR	THERMAL	GAS
45	TORR POWER SAB.	28-Sep-88	390	GUJARAT	PVT	TORR POWER	THERMAL	COAL
46	PAGUTHAN	11-Dec-98	655	GUJARAT	PVT	GPEC	THERMAL	GAS
47	KAWAS GT	19-Mar-93	656.2	GUJARAT	CENTER	NTPC	THERMAL	GAS
48	GANDHAR GT	30-Mar-95	877.39	GUJARAT	CENTER	NTPC	THERMAL	GAS

49	KAKRAPARA	4-Jan-00	440	GUJARAT	CENTER	NPC	NUCLEAR	NUCLEAR
50	KORBA-EAST	12-Dec-07	940	CHATTISGARH	STATE	CSEB	THERMAL	COAL
51	KORBA-WEST	13-Mar-86	840	CHATTISGARH	STATE	CSEB	THERMAL	COAL
52	AMAR KANTAK	15-Jun-08	510	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL
53	SANJAY GANDHI	23-Nov-99	840	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL
54	NASIK	30-Jan-81	880	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL
55	KORADI	13-Jan-83	1040	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL
56	K_KHEDA II	7-Jan-01	840	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL
57	BHUSAWAL	4-May-82	475	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL
58	PARLI	16-Feb-07	920	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL
59	URAN GT	28-Oct-94	912	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	GAS
60	TROMBAY	23-Mar-90	500	MAHARASHTRA	PVT	TATA PCL	THERMAL	OIL
61	TROMBAY_Coal	25-Jan-84	500	MAHARASHTRA	PVT	TATA PCL	THERMAL	COAL
62	DHANU	29-Mar-95	500	MAHARASHTRA	PVT	REL	THERMAL	COAL
63	S.SAROVAR RBPH	7-Mar-06	1000	GUJARAT	STATE	SSVNL	HYDRO	
64	INDIRA SAGAR	23-Mar-05	1000	MADHYA PRADESH	CENTER	NHDC	HYDRO	
65	SIPAT STPS	27-Dec-08	1000	CHATTISGARH	CENTER	NTPC	THERMAL	COAL
66	RAIGARH TPP	17-Jun-08	1000	CHATTISGARH	PVT	JINDAL	THERMAL	COAL
67	K_GUDEM	11-Jan-78	720	ANDHRA PRADESH	STATE	APGENCO	THERMAL	COAL
68	K_GUDEM NEW	28-Feb-98	500	ANDHRA PRADESH	STATE	APGENCO	THERMAL	COAL
69	RAYAL SEEMA	20-Nov-07	840	ANDHRA PRADESH	STATE	APGENCO	THERMAL	COAL
70	SIMHADRI	24-Aug-02	1000	ANDHRA PRADESH	CENTER	NTPC	THERMAL	COAL
71	KAIGA	11-Apr-07	660	KARNATAKA	CENTER	NPC	NUCLEAR	NUCLEAR
72	ENNORE	2-Dec-75	450	TAMIL NADU	STATE	TNEB	THERMAL	COAL
73	TUTICORIN	11-Feb-92	1050	TAMIL NADU	STATE	TNEB	THERMAL	COAL
74	METTUR	16-Feb-90	840	TAMIL NADU	STATE	TNEB	THERMAL	COAL
75	NORTH CHENNAI	24-Feb-96	630	TAMIL NADU	STATE	TNEB	THERMAL	COAL
76	NEYVELI ST I	21-Feb-70	600	TAMIL NADU	CENTER	NLC	THERMAL	LIGN
77	NEYVELI FST EXT	22-Jul-03	420	TAMIL NADU	CENTER	NLC	THERMAL	LIGN
78	M.A.P.P.	20-Sep-85	440	TAMIL NADU	CENTER	NPC	NUCLEAR	NUCLEAR
79	LOWER SILERU	13-Jun-78	460	ANDHRA PRADESH	STATE	APGENCO	HYDRO	
80	NAGARJUNA SAGAR	24-Dec-85	815.6	ANDHRA PRADESH	STATE	APGENCO	HYDRO	
81	SRISAILAM	15-Mar-87	770	ANDHRA PRADESH	STATE	APGENCO	HYDRO	
82	SRISAILAM LBPH	4-Sep-03	900	ANDHRA PRADESH	STATE	APGENCO	HYDRO	
83	SHARAVATHY	9-Apr-77	1006.2	KARNATAKA	STATE	KPCL	HYDRO	
84	KALINADI	25-Mar-84	855	KARNATAKA	STATE	KPCL	HYDRO	
85	IDUKKI	30-Aug-86	780	KERALA	STATE	KSEB	HYDRO	
86	KUNDAH I-V	28-Sep-88	555	TAMIL NADU	STATE	TNEB	HYDRO	
87	KADAMPARI	12-Apr-89	400	TAMIL NADU	STATE	TNEB	HYDRO	
88	VEMAGIRI CCCP	8-Jun-06	388.5	ANDHRA PRADESH	PVT	VEMAGIRI	THERMAL	GAS
89	BELLARY TPS	3-Dec-07	500	KARNATAKA	STATE	KPCL	THERMAL	COAL

According to the Guidelines on common practice (Annex 12, EB 63), Registered CDM projects are not to be included in this step. None of the aforesaid project is registered CDM project[9] as on the start date of the project. Hence, N_{all}= 89

Step 3: Guidelines on common practice (Annex 12, EB 63) recommends identification of plants (within identified in step 2) those apply technologies different that the technology applied in the proposed project activity.

According to paragraph 4 of Guidelines on common practice (Annex 12, EB 63) Different technologies are defined as are technologies that deliver the same output and differ by at least one of the following

- Energy source/fuel
- Feed stock;
- Size of installation (power capacity):
    - Micro (as defined in paragraph 24 of Decision 2/CMP.5 and paragraph 39 of Decision 3/CMP.6);
    - Small (as defined in paragraph 28 of Decision 1/CMP.2);
    - Large;
- Investment climate in the date of the investment decision, inter alia:
    - Access to technology;
    - Subsidies or other financial flows;
    - Promotional policies;
    - Legal regulations;
- Other features, inter alia:
    - Unit cost of output (unit costs are considered different if they differ by at least 20 %);

Now, in plants identified in step 2, 45 plants are coal based, 26 plants are hydro, 10 are gas based, 5 are nuclear plants, 2 plants are lignite based, and one plant is oil based. As the proposed project activity is gas based plant, hence, on the basis of Energy source / fuel all plants excluding 10 gas based can be classified as based on different technology.

Following plants (within identified in step 2) are gas based

[9] Project VEMAGIRI CCCP has been registered as CDM project on 19 Jul- 11 (http://cdm.unfccc.int/Projects/DB/SIRIM1294135064.04/view). As on the start date of the proposed project activity VEMAGIRI CCCP plant was not registered, hence considered for computation of $N_{all.}$

S_NO	NAME	DT_ COMM o last unit	CAPACITY MW AS ON 11/08/2008	STATE	SECTOR	SYSTEM	TYPE	FUEL 1
1	F_BAD CCGT	31-Jul-00	431.59	HARYANA	CENTER	NTPC	THERMAL	GAS
2	ANTA GT	5-Mar-90	419.33	RAJASTHAN	CENTER	NTPC	THERMAL	GAS
3	AURAIYA GT	12-Jun-90	663.36	UTTAR PRADESH	CENTER	NTPC	THERMAL	GAS
4	DADRI GT	26-Feb-94	829.78	UTTAR PRADESH	CENTER	NTPC	THERMAL	GAS
5	ESSAR GT IMP.	10-Aug-95	515	GUJARAT	PVT	ESSAR	THERMAL	GAS
6	PAGUTHAN	11-Dec-98	655	GUJARAT	PVT	GPEC	THERMAL	GAS
7	KAWAS GT	19-Mar-93	656.2	GUJARAT	CENTER	NTPC	THERMAL	GAS
8	GANDHAR GT	30-Mar-95	877.39	GUJARAT	CENTER	NTPC	THERMAL	GAS
9	URAN GT	28-Oct-94	912	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	GAS
10	VEMAGIRI CCCP	8-Jun-06	388.5	ANDHRA PRADESH	PVT	VEMAGIRI	THERMAL	GAS

- Now, evaluating the gas based plants on the basis of Investment climate in the date of the investment decision, inter alia:
  - Access to technology;
  - Subsidies or other financial flows;
  - Promotional policies;
  - Legal regulations;

Further, the Electricity Act came into effect on 10 June 2003 and this act has introduced a uniform regulation for determination of tariff for generation & sale of power. Thus the projects that got commissioned before the introduction of the Electricity Act 2003 are considered to have a different investment climate, and considered under different technology. All identified gas based plants excluding VEMAGIRI CCCP has been commissioned before 10 June 2003, hence can be classified under different technology as per paragraph 4 of Guidelines on common practice (Annex 12, EB 63).

Hence, N_{diff} = 88 (89- 1)

Step 4: According to paragraph 8 Guidelines on common practice (Annex 12, EB 63).factor F is calculated as 1- (N_{diff}/ N_{all}). For the proposed project activity F= 1- (88/89) = 0.011.

Step 5: According to paragraph 8 Guidelines on common practice (Annex 12, EB 63), the proposed project activity is a common practice within a sector in the applicable geographical area if the factor F is greater than 0.2 and N_{all}-Nd_{iff} is greater than 3. y

As evaluated before for the proposed activity within India (applicable geographic area) F= 0.011 and N_{all}-Nd_{iff} = 1, hence it can be observed that proposed project activity is not a common practice.

Step 3 – Impact of CDM Registration

The project activity would obtain the revenues through sale of the emission reductions which would lead to a significant increase in the project IRR (IRR for the project with CDM revenue increases to 15.07%), which alleviates the identified benchmark.

The IRR computations along with its sensitivity analysis demonstrated in Step 1 clearly show that the '**project activity is financially non viable**' even with reasonable variations in the critical assumptions.

The impact of CDM registration is determined with respect to possible realistic future development in the power sector. The legal framework governing the sector is Electricity Act-2003. As per the act the bulk purchase of power across the country should be done through competitive bidding process. This will have serious implication on financial parameters of all the NG based power plants in India. The principal aspects of concerns are described below.

As per this act, going forward, bulk purchase of power by State Electricity Board's (SEB) should be routed through tendering process with selection of power supplier offering lowest rate on competitive basis. Since this act supports the power generation with lower tariff, the power generated by the cheaper but carbon emissive fossil fuels like coal and lignite will be purchased by the SEB's and individual bulk consumer with preference. As a result, the power generated using cleaner fuels like natural gas will get the second priority from the buyers as its generation cost is higher than the generation cost with conventional fuels like coal and lignite. Without CDM benefit this cost has to be borne by the customer. CDM fund will partially absorb this cost and will help to make the power tariff comparatively competitive.

The present direction of power sector reforms indicates further opening up of the power sector and a gradual shift towards more competitive environment. So in future to be in the competition the developers of NG based power plant may face serious pricing pressure. In this futuristic scenario, where the promoter may be forced to offer lower tariff than the present agreed prices, CDM funds will help to reduce the gap between the tariff offered by the proposed project activity and the other power generators/suppliers which generate power with cheaper but high carbon emissive fuels like coal and lignite. This justifies the need of CDM funds for the project activity. The project activity meets the requirements of all the three steps as described in the approved methodology and thereby is additional and not a business as usual case.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

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Project activity adopted the procedures mentioned in the approved methodology (AM0029) to calculate project emissions, baseline emissions, leakage emissions and emission reductions.

The procedures used for calculating these emissions are described below:

Project emissions:

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

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

Where:

$FC_{f,y}$ = is the total volume of natural gas or other fuel 'f' combusted in the project plant or other start-up fuel (m^3 or similar) in year(s) 'y'

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

$$COEF_{f,y} = \sum NCV_y * EF_{CO2,f,y} * OXID_f \tag{2}$$

Where:

NCV_y = is the net calorific value (energy content) per volume unit of natural gas in year 'y' (GJ/m^3) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

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

$OXID_f$ = is the oxidation factor of natural gas

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

Baseline emissions:

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

$$BE_y = EG_{PJ,y} * EF_{BL,CO2,y} \tag{3}$$

As per the methodology the Baseline emission factor is chosen as the minimum of the following three

Option 1: The build margin, calculated according to ACM0002; and
Option 2: The combined margin, calculated according to ACM0002, using a 50/50 OM/BM weight.
Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above, and calculated as follows:

$$EF_{BL,CO2}(tCO_2 / MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6\,GJ / MWh \tag{4}$$

Estimation of Baseline Emission Factor:

So as to have conservative emissions, lower value of BM, CM and the value as per equation 4 has to be chosen as baseline emission factor.

BEF = lowest of (BM, CM, $EF_{BL,CO2}(tCO_2 / MWh)$) (5)

In accordance with the "Tool to calculate the emission factor for an electricity system" Version 02, combined margin CO_2 emission factor and build margin emission factor for grid connected power generation is calculated stepwise as below:

The data used for the calculation of the baseline emission factor was obtained from the baseline calculations published by the CEA, *CO_2 Baseline Database for the Indian Power Sector – Version 5.0*[10], which uses "Tool to calculate the emission factor for an electricity system" Version 02. The relevant parts of the calculations are referenced in the methodology outline below, with detailed data provided in Annex 3. A complete explanation of the assumptions employed by the CEA can be obtained from the *CO_2 Baseline Database for the Indian Power Sector - Version 5.0*.

Step 1: Identify the relevant electricity systems

For determining electricity emission factors, a **project electricity system** is defined by the spatial extent of power plants that are physically connected through transmission and distribution lines to the project activity (e.g. the renewable power plant location or the consumers where electricity is being saved) and that can be dispatched without significant transmission constraints.

The Indian power system is divided into two regional grids, namely NEWNE and Southern grid. Each grid covers several states. Power generation and supply within the regional grid is managed by Regional Load Dispatch Centre (RLDC). The Regional Power Committees (RPCs) provide a common platform for discussion and solution to the regional problems relating to the grid.

Each state in a regional grid meets their demand with their own generation facilities and also with allocation from power plants owned by the central sector such as NTPC and NHPC etc. Specific quotas are allocated to each state from the central sector power plants. Depending on the demand and generation, there are electricity exports and imports between states in the regional grid. There are also electricity transfers between regional grids, and small exchanges in the form of cross-border imports and exports (e.g. from Bhutan). Recently, the Indian regional grids have started to work in synchronous mode, i.e. at same frequency.

States connected to different regional grids

Regional grid	NEWNE Grid				Southern grid
	Northern	Eastern	Western	North Eastern	Southern
States	Haryana, Himachal Pradesh, Jammu & Kashmir, Punjab, Rajasthan, Uttar Pradesh and Uttarakhand	Bihar, Orissa, West Bengal, Jharkhand and Sikkim	Gujarat, Madhya Pradesh, Maharashtra, Goa and Chattisgarh	Arunachal Pradesh, Assam, Manipur, Meghalaya, Mizoram, Nagaland and Tripura	Andhra Pradesh, Karnataka, Kerala and Tamil Nadu
Union Territories	Delhi and Chandigarh	Andaman-Nicobar	Daman & Diu, Dadar & Nagar Haveli	-	Pondicherry, Lakshadweep

10 http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

The NEWNE grid constitutes several states and union territories including North-Eastern states[11]. These states under the regional grid have their own power generating stations as well as centrally shared power-generating stations. While the power generated by own generating stations is fully owned and consumed through the respective state's grid systems, the power generated by central generating stations is shared by more than one state depending on their allocated share. Presently the share from central generating stations is a small portion of their own generation.

For the purpose of determining the emission reductions achieved by the Project the "Tool to calculate the emission factor for an electricity systems" (Version 2, EB 50) states that the "*project electricity system is defined by the spatial extent of the power plants that can be dispatched without significant transmission constraints*". On this basis the Central Electricity Authority, *CO_2 Baseline Database for the Indian Power Sector - Version 5.0*[12] defines the project electricity systems within India in two regional grids. This is justified "*as electricity continues to be produced and consumed largely within the same region, as is evidenced by the relatively small volume of net transfers between the regions, and consequently it is appropriate to assume that the impacts of CDM project will be confined to the regional grid in which it is located*". The project as per the CEA's grid definitions is within the NEWNE regional grid. Also, it is preferable to take the regional grid as project boundary than the state boundary as it minimizes effect of inter state power transactions, which are dynamic and vary widely. Considering free flow of electricity among member states and the union territory the entire NEWNE grid is considered as a single entity for estimation of baseline.

Step 2: Choose whether to include off-grid power plants in the project electricity system (optional)

Project participants may choose between the following two options to calculate the operating margin and build margin emission factor:

Option I: Only grid power plants are included in the calculation.
Option II: Both grid power plants and off-grid power plants are included in the calculation.

The project participant has chosen Option I for the calculation of the operating and build margin emission factor i.e. off-grid power plants are not being included in the calculation.

Step 3: Select a method to determine the operating margin (OM)

The calculation of the operating margin emission factor ($EF_{grid,OM,y}$) is based on one of the following methods:

(a) Simple OM, or
(b) Simple adjusted OM, or
(c) Dispatch data analysis OM, or
(d) Average OM.

For the proposed project activity, simple OM method (option a) has been chosen to calculate the operating margin emission factor ($EF_{grid,\ OM,\ y}$). However, the simple OM method can only be used if low-cost/must-run resources constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production. The low-cost/must-run resources are defined as power plants with low marginal generation costs or power plants that are dispatched independently of the daily or seasonal load of the grid. They typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation.

[11] http://www.cea.nic.in/planning/c%20and%20e/user_guide_ver4.pdf

[12] http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

Share of Low Cost / Must-Run (% of Net Generation)

Grid	2004-05	2005-06	2006-07	2007-08	2008-09
NEWNE	16.8%	18.0%	18.5%	19.0%	17.3%
South	21.6%	27.0%	28.3%	27.1%	22.8%
India	18.0%	20.1%	20.9%	21.0%	18.6%

Ref: CO_2 Baseline Database for the Indian Power Sector – CEA, Version 03 and 04 and 05.

Percentage of total grid generation by low cost/must run plants (on the basis of average of five most recent years) = 17.94 %

The calculation above shows that the generation from low-cost/must-run resources constitutes less than 50% of total grid generation, hence usage of the **Simple OM method** in the project case is justified.

The Simple OM emission factor can be calculated using either of the two following data vintages for years(s) *y*:

- Ex ante option: If the ex ante option is chosen, the emission factor is determined once at the validation stage, thus no monitoring and recalculation of the emissions factor during the crediting period is required. For grid power plants, use a 3-year generation-weighted average, based on the most recent data available at the time of submission of the CDM-PDD to the DOE for validation. For off-grid power plants, use a single calendar year within the 5 most recent calendar years prior to the time of submission of the CDM-PDD for validation.

or

- Ex post option: If the ex post option is chosen, the emission factor is determined for the year in which the project activity displaces grid electricity, requiring the emissions factor to be updated annually during monitoring. If the data required to calculate the emission factor for year y is usually only available later than six months after the end of year y, alternatively the emission factor of the previous year (y-1) may be used. If the data is usually only available 18 months after the end of year y, the emission factor of the year proceeding the previous year (y-2) may be used. The same data vintage (y, y-1 or y-2) should be used throughout all crediting periods.

The project proponent would estimate the simple OM emission factor *ex post* and use the 3-year generation-weighted average. In case the data required to calculate the emission factor for year y is made available later than six months after the end of year y, the emission factor of the previous year y-1 would be used and if the data is made available 18 months after the end of year y, the emission factor of the year proceeding the previous year y-2 would be used. The same data vintage (y, y-1 or y-2) would be used throughout all crediting periods.

Step 4: Calculate the operating margin emission factor according to the selected method

The simple OM method has been selected as justified above. The simple OM emission factor is calculated based on the net electricity generation of each power unit and a CO_2 emission factor for each power unit, as follows:

$$EF_{grid,OM,simple,y} = \frac{\sum_m EG_{m,y} \cdot EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:

$EF_{grid,OMsimple,,y}$ = Simple operating margin CO_2 emission factor of in year y (tCO_2/MWh)

$EG_{m,y}$	=	Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)
$EF_{EL,m,y}$	=	CO_2 emission factor of power unit m in year y (tCO_2/MWh)
m	=	All power units serving the grid in year y except low-cost / must-run power units
y	=	The relevant year as per the data vintage chosen in step 3 i.e. the three most recent years for which data is available at the time of monitoring (ex post option)

Determination of $EF_{EL,m,y}$

The emission factor of each power unit m has been determined as follows:

$$EF_{EL,m,y} = \frac{\sum_{m} FC_{i,m,y} \cdot NCV_{i,y} \cdot EF_{CO2,i,y}}{EG_{m,y}}$$

$EF_{EL,m,y}$	=	CO_2 emission factor of power unit m in year y (tCO_2/MWh)
$FC_{i,m,y}$	=	Amount of fossil fuel type i consumed by power unit m in year y (Mass or volume unit)
$NCV_{i,y}$	=	Net calorific value (energy content) of fossil fuel type i in year y (GJ / mass or volume unit)
$EF_{CO2,i,y}$	=	CO_2 emission factor of fossil fuel type i in year y (tCO_2/GJ)
$EG_{m,y}$	=	Net electricity generated and delivered to the grid by power unit m in year y (MWh)
m	=	All power units serving the grid in year y except low-cost / must-run power units
I	=	All fossil fuel types combusted in power plant / unit m in year y
y	=	The relevant year as per the data vintage chosen in step 3 i.e. the three most recent years for which data is available at the time of monitoring (ex post option)

Determination of $EG_{m,y}$

Since, the calculations consider only grid power plants, $EG_{m,y}$ should have been determined as per the data provided by the Central Electricity Authority (CEA) CO_2 Baseline Database for the Indian Power Sector.

In India, the Central Electricity Authority (CEA) has estimated the baseline emission factor for the power sector. This data has also been endorsed by the DNA and is the most authentic information available in the public domain. The details of same can be found on CEA website at http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm and have been summarised below:

Operating Margin Estimation for NEWNE Grid (tCO_2 / MWh)		
Year	**Operating Margin (tCO_2e/MWh)**	**Net Generation (GWh)**
2006-07	1.0085	465,361
2007-08	0.9999	496,119
2008-09	1.0066	509,776

Generation Weighted Average OM	1.0049 tCO_2e / MWh

Step 5: Identify the group of power units to be included in the build margin

The sample group of power units *m* used to calculate the build margin consists of either:

a) The set of five power units that have been built most recently, or
b) The set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently.

Project proponents should use the set of power units that comprises the larger annual generation.

Since in India, the installed capacity and corresponding annual generation from power plants is quite high, the sample group containing set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently comprise the sample group with the larger annual generation. Thus the sample group *m* consisting of option (b) is used for the estimation of build margin.

In terms of vintage of data, project proponents can choose between one of the following two options:

Option 1: For the first crediting period, calculate the build margin emission factor ex-ante based on the most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation. For the second crediting period, the build margin emission factor should be updated based on the most recent information available on units already built at the time of submission of the request for renewal of the crediting period to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used. This option does not require monitoring the emission factor during the crediting period.

Option 2: For the first crediting period, the build margin emission factor shall be updated annually, ex-post, including those units built up to the year of registration of the project activity or, if information up to the year of registration is not yet available, including those units built up to the latest year for which information is available. For the second crediting period, the build margin emissions factor shall be calculated ex-ante, as described in option 1 above. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used.

The project proponent wishes to choose option 2.

Step 6: Calculate the build margin emission factor

The build margin emissions factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units m during the most recent year y for which power generation data is available, calculated as follows:

$$EF_{grid,OM,simple,y} = \frac{\sum_m EG_{m,y} \cdot EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:

$EF_{grid,\ BM,\ y}$	=	Build margin CO_2 emission factor in year y (tCO_2/MWh)
$EG_{m,y}$	=	Net quantity of electricity generated and delivered to the grid by power unit *m* in year y (MWh)
$EF_{EL,\ m,\ y}$	=	CO_2 emission factor of power unit *m* in year y (tCO_2/MWh)
m	=	Power units included in the build margin

Y = Most recent historical year for which power generation data is available

Calculations for the Build Margin emission factor $EF_{gid,\ BM,\ y}$ is based on the most recent information available on the plants already built for sample group *m* at the time of PDD submission. The sample group *m* consists of the power plant capacity additions in the electricity system that comprise 20 % of the system generation and that have been built most recently.

In India, the Central Electricity Authority (CEA) has estimated the baseline emission factor for the power sector. This data has also been endorsed by the DNA and is the most authentic information available in the public domain. The details of same can be found on CEA website at http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm and have been summarised below:

Build Margin Estimation for NEWNE Grid (tCO_2e / MWh)	
BM 2008-09 ($EF_{grid,\ BM,\ y}$)	**0.6752**

Step 7: Calculate the combined margin emissions factor

The combined margin emissions factor is calculated as follows:

$$EF_{CO_2} = EF_{grid,OM,y} \times w_{OM} + EF_{grid,BM,y} \times w_{BM}$$

Where:

$EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year y (tCO_2/MWh)
$EF_{grid,OM,y}$ = Operating margin CO_2 emission factor in year y (tCO_2/MWh)
w_{OM} = Weighting of operating margin emissions factor (%)
w_{BM} = Weighting of build margin emissions factor (%)

The following default values should be used for w_{OM} and w_{BM}:

- Wind and solar power generation project activities: w_{OM} = 0.75 and w_{BM} = 0.25 (owing to their intermittent and non-dispatchable nature) for the first crediting period and for subsequent crediting periods.
- All other projects: w_{OM} = 0.5 and w_{BM} = 0.5 for the first crediting period, and w_{OM} = 0.25 and w_{BM} = 0.75 for the second and third crediting period, unless otherwise specified in the approved methodology which refers to this tool.

As mentioned before, the CEA has calculated the baseline emission factors for various regional grids in India according to the formulas specified above. As this is the most authentic information available in the public domain. The baseline emission factor used in the calculation of baseline emissions for the proposed project activity is being referred to the same for transparency and conservativeness[13].

Combined Margin Estimation for NEWNE Grid (tCO_2e / MWh)	
Generation Weighted Average OM ($EF_{grid,\ OM,y}$)	**1.0049**
BM ($EF_{grid,\ BM,\ y}$)	**0.6752**
Combined Margin (EF_{CO2})	**0.8401**

Emission factor of Baseline Technology - Coal based power plant (sub-critical)

Parameter	Value	Units	Source

[13] http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

Emission Factor of Coal ($COEF_{BL}$)	90.6	tCO_2/TJ	CEA CO_2 Baseline Database Version 5.0
Energy efficiency of power generation with coal (sub-critical technology) (η_{BL})	33%[14]	%	
Emission factor of the Baseline Technology $\left(EF_{BL,CO2} = \frac{COEF_{BL}}{\eta_{BL}} * 3.6 \right)$	0.9943	tCO_2e / MWh	Calculated

Since,

BEF = lowest of (BM, CM, $EF_{BL,CO2}\,(tCO_2 / MWh)$) (5)

Emission factor as per Option 1: Build margin calculated according to ACM0002

Build Margin for NEWNE Grid (EF_{CO2}) = 0.6752 tCO_2e / MWh

Emission factor as per Option 2: Combined margin calculated according to ACM0002

Combined Margin for NEWNE Grid (EF_{CO2}) = 0.8401 tCO_2e / MWh

Emission factor as per Option 3: Baseline Technology - Coal based power plant (sub-critical)

Emission factor of the Baseline Technology = 0.9943 tCO_2e / MWh

Baseline Emission factor ($EF_{BL,CO2,y}$) = lowest of (BM, CM, $EF_{BL,CO2}\,(tCO_2 / MWh)$)

Baseline Emission factor ($EF_{BL,CO2,y}$) = Min (0.6752, 0.8401, 0.9943) = 0.6752 tCO_2e / MWh

Leakage:

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

Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, regasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity.

In case LNG is used in the project plant: the CO_2 emissions would be from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH_4,y} + LE_{LNG,CO_2,y} \quad (4)$$

Where,

LE_y = Leakage emissions during the year y in tCO_2e
$LE_{CH4,y}$ = Leakage emissions due to fugitive upstream CH4 emissions in the year y in tCO_2e
$LE_{LNG,CO2,y}$ = Leakage emissions due to fossil fuel combustion/electricity consumption associated

[14] CEA CO_2 Baseline Database Version 5.0 assumes Net Heat Rate of 500 MW coal based power plants as 2,622 kCal/kWh. This is used to calculate efficiency of sub-critical coal based power generation as = $\frac{1}{2622} * \frac{3600}{4.186}$ = 33%

with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in tCO_2e

There will be no LNG consumption in the project activity, so $LE_{LNG,CO2,y}$ will be zero.

Fugitive methane emissions

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

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

Where

$LE_{CH4,y}$	=	Leakage emissions due to fugitive upstream CH4 emissions in the year y in t CO_2e
FC_y	=	Quantity of natural gas combusted in the project plant during the year y in m³
$NCV_{NG,y}$	=	Average net calorific value of the natural gas combusted during the year y in GJ/m³
$EF_{NG,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in tCH_4 per GJ fuel supplied to final consumers
$EG_{PJ,y}$	=	Electricity generation in the project plant during the year in MWh
$EF_{BL,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in tCH_4 per MWh electricity generation in the project plant, as defined below
GWP_{CH4}	=	Global warming potential of methane valid for the relevant commitment period

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL, upstream, CH4}$) has been calculated consistently with the baseline emission factor ($EF_{BL,CO2}$) used in before. The lowest baseline emission factor has been found to be the one calculated as per build margin method, so the same calculation procedure has been adopted to calculate $EF_{BL, upstream, CH4}$. The same has been described below.

$$EF_{BL,upstream,CH4} = \frac{\sum_j FF_{j,k} * EF_{k,upstream,CH4}}{\sum_j EG_j} \quad (8)$$

Where:

$EF_{BL,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant
j	=	Plants included in the build margin
FF_j	=	Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin
$EF_{k,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type) in t CH_4 per MJ fuel produced
EG_j	=	Electricity generation in the plant j included in the build margin in MWh/a plant included in the operating margin

The default values used in the project activity are as follows:

Sl. No	Parameter	Default Value	Remarks
1	Emission factor for fugitive CH_4 upstream emissions for coal	0.8 tCH_4/kt coal	Most of the coal production in India comes from open pit mines contributing over 81% of the total production. A number of large open pit mines of over 10 million tonnes per annum capacity are in operation. Underground mining currently accounts for around 19% of national output. (http://www.mbendi.co.za/indy/ming/coal/as/in/p0005.htm). Hence 0.8 tCH_4/kt coal value is used for surface mining
2	Emission factor for fugitive CH_4 upstream emissions for Oil	4.1 tCH_4/PJ	As per the Table 2 of the methodology. This value includes for oil production, transport, refining and storage.
3	Emission factor for fugitive CH_4 upstream emissions for Natural Gas	160 tCH_4/PJ	As per the Table 2 of the methodology
4	Oxidation factor of natural gas	1.000	CEA CO2 Baseline Database Version 5.0

Emission Reductions:

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

$$ER_y = BE_y - PE_y - LE_y$$

Where:

ER_y = Emission reductions in year y (t CO_2e/y).
BE_y = Baseline Emissions in year y (t CO_2e/y).
PE_y = Project emissions in year y (t CO_2e/y).
LE_y = Leakage emissions in year y (t CO_2e/y).

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

The following are the list of data and parameters that are not monitored throughout the crediting period but that are determined only once and thus remains fixed throughout the credit period and that are available when validation is undertaken.

Data / Parameter:	$OXID_f$
Data unit:	-
Description:	Oxidation factor of natural gas used to estimate project emissions
Source of data used:	CEA CO2 Baseline Database Version 5.0
Value applied:	1.000
Justification of the choice of data or description of measurement methods and procedures actually	IPCC default value of the current year is considered. The same was suggested in the GHG inventory information report submitted by India's Initial National Communication (Chapter 2) wherein it is mentioned that in the case of petroleum products and natural gas, the use of default emissions would be fairly accurate due to relatively low variation in quality of these fuels across the

applied :	globe, as compared to coal.
Any comment:	-

Data / Parameter:	**$EF_{CO2,f,y}$**
Data unit:	tCO_2/TJ
Description:	Emission factor of natural gas used to estimate project emissions
Source of data used:	CEA CO2 Baseline Database Version 5.0
Value applied:	49.4
Justification of the choice of data or description of measurement methods and procedures actually applied :	A gas analysis of Tripura asset installations was done at three different wells. Using the carbon content and NCV of gas, the average CO_2 emission factor of natural gas in the region was found to be 58.51 tCO_2/TJ which is higher than the national value of 49.4 tCO_2/TJ provided in the CEA CO_2 Baseline database Version 5.0. Hence use of the national default value is conservative.
Any comment:	-

Data / Parameter:	**$EF_{NG,Upstream,CH4}$**
Data unit:	tCH_4/GJ
Description:	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution
Source of data used:	Table 2 of methodology ACM0029 Version 3
Value applied:	160 tCH_4/TJ
Justification of the choice of data or description of measurement methods and procedures actually applied :	Since reliable and accurate national data on fugitive CH_4 emissions is not available, the default values provided in table 2 of the methodology have been used.
Any comment:	-

Data / Parameter:	**$EF_{BL,upstream,CH4}$**
Data unit:	tCH_4/MWh
Description:	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in electricity generation in the project plant
Source of data used:	As per data provided by CEA CO_2 Baseline Database for the Indian Power Sector – Version 5.0
Value applied:	0.0006
Justification of the choice of data or description of measurement methods and procedures actually applied :	This value has been calculated based on consumption of coal, lignite, natural gas and naptha in Build Margin Plants using the fugitive emission factors provided in table 2 of AM0029 Version 3. The calculation has also been detailed in section B.6.3.
Any comment:	This value is determined ex-ante and will be fixed for the crediting period.

Data / Parameter:	**GWP_{CH4}**
Data unit:	-

Description:	Global warming potential of methane
Source of data used:	IPCC, FAR WG I Technical Summary, page 33, Table TS.2
Value applied:	21
Justification of the choice of data or description of measurement methods and procedures actually applied :	Not Applicable
Any comment:	This value is determined ex-ante and will be fixed for the crediting period.

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

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Baseline Emissions (BE_y)

Parameter	Value	Units	Source
Baseline Emission factor ($EF_{BL,CO2,y}$)	0.6752	tCO_2/MWh	CEA Database Ver 5.0
Capacity of power plant	726.6	MW	Technical Specifications
Plant Load Factor	80	%	Technical Specifications
Gross electricity generation	5092	GWh	Calculated
Internal electricity consumption (3.95%)	187	GWh	Calculated
Net Energy Generation ($EG_{PJ,y}$)	4,905	GWh	Calculated
Baseline Emissions (BE_y) = EF_{CO2} x $EG_{PJ,y}$	3,311,511	tCO_2e/y	Calculated

Project activity emissions (PE_y)

The CO_2 emissions from electricity generation (PE_y) are calculated as follows:

$$COEF_{f,y} = \sum NCV_y * EF_{CO2,f,y} * OXID_f$$

Where:

NCV_y = is the net calorific value (energy content) per volume unit of natural gas in year ‘y’ (GJ/m^3) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

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

$OXID_f$ = is the oxidation factor of natural gas

For ex-ante calculations,

NCV_y = 8,250 kcal/Sm^3

$OXID_f$ = 0.995 as per IPCC default data

$EF_{CO2,f,y}$ = 49.4 tCO_2/TJ as per IPCC default data

Hence, $COEF_{f,y}$ = 8,250 kcal/Sm^3 x 4.186 x 49.4 tCO_2/TJ x 0.995 x 10^{-9} = 0.002 tCO_2/Sm^3

$$PE_y = \sum FC_{f,y} * COEF_{f,y} \qquad (1)$$

Where:

$FC_{f,y}$ = is the total volume of natural gas or other fuel 'f' combusted in the project plant or other start-up fuel (m^3 or similar) in year(s) 'y'

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

For ex-ante calculations,

PE_y = 966,175,548 Sm^3/yr x 0.002 tCO_2/Sm^3 = 1,648,300 tCO_2/yr

Leakage (LE_y)

Leakage emissions are calculated as follows:

$$LE_y = LE_{CH_4,y} + LE_{LNG,CO_2,y} \quad (4)$$

Where,

LE_y = Leakage emissions during the year y in tCO_2e

$LE_{CH4,y}$ = Leakage emissions due to fugitive upstream CH4 emissions in the year y in tCO_2e

$LE_{LNG,CO2,y}$ = Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in tCO_2e

There will be no LNG consumption in the project activity, so $LE_{LNG,CO2,y}$ will be zero.

Fugitive methane emissions

$$EF_{BL,upstream,CH4} = \frac{\sum_j FF_{j,k} * EF_{k,upstream,CH4}}{\sum_j EG_j} \quad (8)$$

Where:

$EF_{BL,upstream,CH4}$ = Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in tCH_4 per MWh electricity generation in the project plant

J = Plants included in the build margin

FF_j = Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin

$EF_{k,upstream,CH4}$ = Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type) in t CH_4 per MJ fuel produced

EG_j = Electricity generation in the plant j included in the build margin in MWh/a plant included in the operating margin

As per data provided by CEA CO_2 Baseline Database for the Indian Power Sector – Version 5.0

Calculation of fugitive emission factor of build margin									
Fuel	**Emissions (tCO_2e)**	**Net Calorific Value (kcal/kg)**	**Fuel Emission Factor (gCO_2/MJ)**	**Emission factor (tCO_2e/ton)**	**Fuel consumption**		**Fugitive emission factor**		**Fugitive emissions (tCO_2e)**
					(1000 t)	**(PJ)**	**(tCH_4/1000t)**	**(tCH_4/PJ)**	
Coal	65,000,527	3,755.00	90.6	1.424	45,644		0.8		36,515
Lignite	1,943,588	2,842.81	101	1.196	1,625		0.8		1,300
Natural gas	1,046,285	8,800.00	49	1.820		21.18		160	3,389
Naphtha	1,306,987	11,300.00	66	3.122		19.80		4.1	81
Total	**69,297,387**	**-**	**-**	**-**	**-**		**-**		**41,285**

Net electricity generation (GWh) corresponding to build margin from CEA Database	**71,894**

Fugitive emission factor (tCH_4/GWh)	**0.0006**

$$LE_{CH4,y} = \lfloor FC_y * NCV_y * EF_{NG,upstream,CH4} - EG_{PJ,y} * EF_{BL,upstream,CH4} \rfloor * GWP_{CH4} \quad (5)$$

Where

$LE_{CH4,y}$	=	Leakage emissions due to fugitive upstream CH4 emissions in the year y in t CO_2e
FC_y	=	Quantity of natural gas combusted in the project plant during the year y in m³
$NCV_{NG,y}$	=	Average net calorific value of the natural gas combusted during the year y in GJ/m³
$EF_{NG,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in tCH_4 per GJ fuel supplied to final consumers
$EG_{PJ,y}$	=	Electricity generation in the project plant during the year in MWh
$EF_{BL,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in tCH_4 per MWh electricity generation in the project plant, as defined below
GWP_{CH4}	=	Global warming potential of methane valid for the relevant commitment period

Leakage Emission Calculation		
Fugitive Methane Emission from NG consumption		
Quantity of natural gas combusted in the project plant per year	966,175,548	Sm^3/year
Average Net Calorific Value of the natural gas combusted	8,250	kCal/Sm^3
Emission factor for fugitive emission for NG	0.00016	tCH_4/GJ
Fugitive Methane Emission from NG consumption	112,111	tCO_2e/year
Fugitive emission from fossil fuel in absence of the project		
Electricity generation from project per annum	5,092	GWh/year
Combined fugitive emission factor (coal & gas)	0.0006	tCH_4/MWh
Total fugitive emission from fossil fuels in absence of the project	61,406	tCO_2e/year
Global Warming Potential of methane	21	
Net leakage attributable to the project activity	50,705	tCO_2e/year
Effective leakage emissions	**50,705**	**tCO_2e/year**

Emission reductions (BE_y) are calculated as follows:

Baseline Emissions (BE_y)	3,311,511	tCO_2e/year
Project Activity Emissions (PE_y)	1,648,300	tCO_2e/year
Leakage (LE_y)	50,705	tCO_2e/year
Emission Reductions (ER_y) = BE_y - PE_y - LE_y	**1,612,506**	**tCO_2e/year**

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

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Year	Estimation of Project activity emissions (tonnes of CO_2e)	Estimation of Baseline emissions (tonnes of CO_2e)	Estimation of Leakage (tonnes of CO_2e)	Estimation of overall emission reductions (tonnes of CO_2e)
1st Jan 2013-31st Dec 2013	1,648,300	3,311,511	50,705	1,612,506

1st Jan 2014-31st Dec 2014	1,648,300	3,311,511	50,705	1,612,506
1st Jan 2015-31st Dec 2015	1,648,300	3,311,511	50,705	1,612,506
1st Jan 2016-31st Dec 2016	1,648,300	3,311,511	50,705	1,612,506
1st Jan 2017-31st Dec 2017	1,648,300	3,311,511	50,705	1,612,506
1st Jan 2018-31st Dec 2018	1,648,300	3,311,511	50,705	1,612,506
1st Jan 2019-31st Dec 2019	1,648,300	3,311,511	50,705	1,612,506
1st Jan 2020-31st Dec 2020	1,648,300	3,311,511	50,705	1,612,506
1st Jan 2021-31st Dec 2021	1,648,300	3,311,511	50,705	1,612,506
1st Jan 2022-31st Dec 2022	1,648,300	3,311,511	50,705	1,612,506
Total (tCO_2e)	**16,483,000**	**33,115,110**	**507,050**	**16,125,060**

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

B.7.1 Data and parameters monitored:

The following tables include specific information on how the data and parameters that need to be the parameters would actually be collected during monitoring for the project activity. Only data that is determined only once for the crediting period but that becomes available only after validation of the project activity are included here.

Data / Parameter:	**$EG_{PJ,y}$**
Data unit:	MWh
Description:	Net electricity exported to grid by the project activity
Source of data to be used:	Invoices raised by OTPC that are based on the data measured and recorded from main energy meter installed at the inter-connection point with the grid
Value of data applied for the purpose of calculating expected emission reductions in section B.5	4,904,627
Description of measurement methods and procedures to be applied:	Monthly Joint Meter readings taken in presence of OTPC and grid officials.
QA/QC procedures to be applied:	Meters will be of accuracy class 0.2s or better and shall be calibrated as per operation best practices at desired frequencies and the documents for the same will be maintained.
Any comment:	The archived data will be kept for 2 years beyond the Crediting Period (CP)

Data / Parameter:	**$FC_{f,y}$**
Data unit:	Thousand SCM (TSCM)

Description:	Annual quantity of fuel "f" consumed in project activity
Source of data to be used:	Fuel flow meter reading at project boundary
Value of data applied for the purpose of calculating expected emission reductions in section B.5	966,175
Description of measurement methods and procedures to be applied:	The total fuel consumption will be monitored both at supplier and project end for cross verification and measured in standard cubic meters
QA/QC procedures to be applied:	Natural gas supply metering to the project will be subject to regular (in accordance with stipulation of the meter supplier) maintenance and testing to ensure accuracy. The readings will be cross-checked by the gas company.
Any comment:	The archived data will be kept for 2 years beyond the Crediting Period (CP)

Data / Parameter:	**NCV_y**
Data unit:	GJ/Sm^3 (or kcal/scm)
Description:	Net calorific value of fuel type f
Source of data to be used:	Fuel supplier
Value of data applied for the purpose of calculating expected emission reductions in section B.5	8,250
Description of measurement methods and procedures to be applied:	The calorific value of the gas would be provided by the supplier and recorded and verified by the project participant. Measurements would be taken on a fortnightly basis.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	The archived data will be kept for 2 years beyond the Crediting Period (CP)

Data / Parameter:	**$EF_{CO2,f,y}$**
Data unit:	tCO_2/m^3
Description:	CO_2 emission coefficient of natural gas
Source of data to be used:	Calculated based on IPCC default data and actual calorific value of natural gas used in project activity
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.002
Description of measurement methods	Will be calculated according to the below formula: $COEF_{f,y} = \sum NCV_y * EF_{CO2,f,y} * OXID_f$

and procedures to be applied:	
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	-

Data / Parameter:	$\mathbf{EF_{BL,CO2,y}}$
Data unit:	tCO_2/MWh
Description:	Baseline CO_2 emission factor
Source of data to be used:	As per data provided by CEA CO_2 Baseline Database
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Lowest of (BM, CM, $EF_{BL,CO2}$) = Build Margin (Option 2) = 0.6752 tCO_2e/MWh
Description of measurement methods and procedures to be applied:	As per the methodology the Baseline emission factor is chosen as the minimum of the following three: Option 1: The build margin, calculated according to ACM0002; and Option 2: The combined margin, calculated according to ACM0002, using a 50/50 OM/BM weight. Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above, and calculated as follows: $$EF_{BL,CO2}\,(tCO_2/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6\,GJ/MWh$$ The CEA calculates Combined Margin and Build Margin Emission Factor as per 'Tool to calculate the emission factor for an electricity system", version 02 for each year. It also provides the data to calculate emission factor for power generation from coal using sub-critical technology.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	For ex-ante estimation, the Build Margin Emission Factor estimated by CEA CO_2 Baseline Database Version 5.0 as per 'Tool to calculate the emission factor for an electricity system", version 02 for the year 2008-09 has been used.

Data / Parameter:	$\mathbf{\eta_{BL}}$
Data unit:	%
Description:	Energy efficiency of power generation in the baseline scenario from coal using sub-critical technology
Source of data to be used:	CEA CO_2 Baseline Database or other third party documentation
Value of data applied for the purpose of calculating expected	33%

emission reductions in section B.5	
Description of measurement methods and procedures to be applied:	The CEA CO_2 Baseline Database may directly provide the efficiency of the baseline scenario i.e. a coal based power generation system based on the sub-critical technology or it may provide the Net Station Heat Rate (Net SHR) that may be used to calculate the baseline efficiency as follows: $\eta_{BL} = \frac{1}{Net\ SHR} * \frac{3600}{4.186}$ In case data is not available in the CEA CO_2 Baseline Database, other third party documentation may be used.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	For ex-ante estimation, the baseline efficiency has been calculated using the Net Station Heat Rate value available in the CEA CO_2 Baseline Database Version 5.0 for a 500 MW coal based sub-critical power plant.

Data / Parameter:	**$COEF_{BL}$**
Data unit:	tCO_2/TJ
Description:	Emission factor of coal
Source of data to be used:	Lower of national values or IPCC default value
Value of data applied for the purpose of calculating expected emission reductions in section B.5	90.6
Description of measurement methods and procedures to be applied:	The national value may be obtained from the CEA CO_2 Baseline Database or other publically available documentation. As a conservative measure, the lower of national value or IPCC default value would be used for determination of baseline emission factor.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	Local values for emission factor of coal are not available. Therefore, for ex-ante estimation, the emission factor of coal has been drawn from the CEA CO_2 Baseline Database Version 5.0. This is a conservative value as compared to the default IPCC value of 94.6 tCO_2/TJ.

B.7.2. Description of the monitoring plan:

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Description of the Monitoring Plan:

Parameters monitored will be quantity and quality of fuel used, total power generated and power exported to the grid. All monitoring and control functions will be done as per the internally accepted standards and norms of OTPC.

The project revenue is based on the units exported as measured by main and check energy meters at the inter-connection point. The monitoring and verification system would mainly comprise of these meters as far as power export is concerned. The export of electricity will be through invoices raised by OTPC.

The natural gas utilized will also be monitored. The measurement of the quantity of natural gas used will produce evidence that the energy is being generated with reduced CO_2 emissions as compared to selected grid emissions.

Project Parameters affecting Emission Reduction:

Total power generated

The total power generated by the power project will be measured in the plant premises to the best accuracy and will be recorded, monitored on a daily basis. All main measurement devices will be calibrated as per best practices at desired frequencies. The parameter will substantiate the smooth operations of the project and can be used for cross-checking of the energy exported to the grid.

Power exported to the grid

The project revenue will depend on net units exported by OTPC. All metering and check metering facilities will be installed at the inter-connection point or delivery point where the power from the Power Station Switch Yard Bus is being injected into the Transmission Network. The actual net quantity of power exported will be arrived at after joint verification of data by both OTPC and grid authorities.

Fuel Parameters of the Combined Cycle Power Plant

Fuel Used

The fuel that has been envisaged for the proposed project is natural gas from gas wells. OTPC has entered into a Gas Sale and Purchase Agreement with ONGC for supply of natural gas to the project activity.

The following parameters will be monitored at the gas receiving station.

Flow of Natural Gas to OTPC

Natural gas will be supplied by ONGC through its pipeline from gas wells up to the proposed power plant boundary. It has been envisaged that, fuel gas supplier will have the necessary pressure regulation, conditioning and tariff gas metering station at their gas supply terminal near proposed power plant to ensure proper monitoring and quantification of gas intake in the power plant.

Quantity of the fuel used in the Gas Turbine

The quantity of NG used in the Gas Turbine would be monitored on a daily basis. Measurement devices will be calibrated in accordance with stipulation of the meter supplier.

Calorific value of Natural Gas

The properties of NG like chemical composition, calorific value etc. varies from well to well. The performance of GTG will also depend on the properties of the NG used as fuel. The properties of the NG including its composition will be analysed using gas chromatography technology. NCV will be calculated based on chemical composition of gas.

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):

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Date of completion of baseline study and monitoring methodology: 10/02/2010

OTPC has determined the baseline and monitoring methodology for the project activity. The entity is a project participant listed in Annex-I where the contact information has also been provided.

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:

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23rd June 2008

According to Paragraph 67 of the Report on 41st meeting of the Executive Board of the Clean Development Mechanism, "*the start date shall be considered to be the date on which the project participant has committed to expenditures related to the implementation or related to the construction of the project activity. This, for example, can be the date on which contracts have been signed for equipment or construction/operation services required for the project activity.*" Hence, the start date of the project activity has been considered as the date of Notification of Award of Turnkey EPC Contract to Bharat Heavy Electricals Limited.

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

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25 years 0 month

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:

>>

NA

C.2.1.2. Length of the first crediting period:

>>

NA

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>> 01/01/2013

(Date when the project will be submitted to UNFCCC for request for registration or Project commissioning date whichever is later)

C.2.2.2. Length:

>>

10 years

SECTION D. Environmental impacts

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

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The project activity has obtained Environmental Clearance from the Ministry of Environment & Forest (MoEF), Government of India (GoI) on 7th February 2007. For this purpose a Rapid Environmental Impact Assessment (REIA) study was conducted to predict the possible environmental impacts due to construction and operation of the project, suggesting environmental remedies/safeguards and formulating an effective Environmental Mitigation Plan to ensure an environmentally sustainable development.

The major environmental disciplines studied include geology, soils, surface and ground water hydrology, meteorology, landuse, surface and ground water quality, air quality, terrestrial and aquatic ecology, demography and socioeconomics and noise. The study consists of field data generated over a two and half month period / one season data (March 27 to 1st week of June, 2005) along with relevant data collected from various agencies on the above disciplines.

The environmental impacts were identified as follows:

Land-use

The land for the project activity mostly comprises of degraded forest land, principally covered by sal species and part of it is private agricultural land. This forest land and agricultural land would be converted to industrial use. To this extent, compensatory afforestation would be taken up.

Air Quality

The fuel for the project would be natural gas, resulting in emissions to ambient air from its combustion. The point source emissions would consist of Oxides of Nitrogen (NOx). The prediction of the atmospheric dispersion of the stack emissions and estimation of the incremental and resultant ground level concentrations of NOx have been predicted with the Industrial Source Complex (ISC) Model.

Surface Water Quality

The quantity of effluent that would be discharged to the river Gumti, due to the power plant operations is about 1.67% of the average flow of the Gumti. The different plant effluents would be subjected to various forms of treatment and would be monitored to conform to more than the applicable discharge standards. As the river flow is almost 60 times the wastewater flow, there would be no tangible change in the water quality of the river Gumti, due to dilution, which would maintain its present quality.

Ground Water Quality

As regards ground water, about 12 tonnes of sludge per day from the dewatering system would need to be disposed. This sludge would have to be disposed in a designated area, to be carefully chosen in consultation with the State Pollution Control Board and the local district administration. The disposal site would be selected downstream of the ground water gradient near to a depression so that the ground water, which is used for drinking purposes by the villagers, is not affected.

Fuel Condensate

The fuel gas sourced from ONGC gas wells in Tripura will have negligible amount of gas condensate as shown in the gas analysis. However, fuel gas condensate will be collected in gas condensate tanks in gas conditioning area and GT Final Filter area in underground tanks separately. It will be periodically disposed offsite.

Ecology

The impact of the construction activities would be primarily confined to the project site. The land for project activity is principally degraded forest land, primarily covered by sal species. This site is surrounded by Reserved Forests and the Trishna Sanctuary is only 8 km away. The resultant ambient air quality is well within the applicable standards and much below the threshold limit for damage to terrestrial flora. As such, the impact on the terrestrial ecosystem would be negligible due to this phenomenon.

As there would not be any tangible change in the water quality of the Gumti river due to the waste water discharges from the plant operations, no adverse effects on the aquatic ecosystem are envisaged.

Social Environment

Very few people would be affected due to the project activity. Most of the landholders are small and the landholding varies from 0.07 acre to 0.52 acre. They also have alternative land or income for sustenance. A socio-economic survey of these persons reveals that the majority would prefer monetary compensation at suitable and commensurate levels. OTPC has agreed to provide adequate compensation to the affected families so as to procure similar land in the adjacent areas without any additional financial contribution from any other sources.

Peripheral development of physical and social infrastructure in the deficient villages would be taken up towards betterment of the overall environment and quality of life of the people in the vicinity, particularly as the area is backward and deprived. Augmentation of infrastructure will be undertaken in this area. Apart from this, projects like child immunization and health care camps would be organized in the villages.

Noise

The major noise generating sources of the power plant are the turbine generators and cooling towers. The noise dispersion model shows that the noise levels from these sources decrease to 40 dB(A) within the plant boundary and is decreasing with the increasing distance from the source of emission. As such, the ambient noise levels would remain unaffected and no disturbances would be caused to the community.

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:

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As discussed above, the project activity would not have any adverse environmental impacts. The project activity has already obtained an Environmental Clearance from the Ministry of Environment & Forest (MoEF), Government of India (GoI). A Rapid Environmental Impact Assessment (REIA) study has been carried out to predict the possible environmental impacts due to construction and operation of the project which also provides suggestions for environmental remedies/safeguards and an effective Environmental Mitigation Plan to ensure an environmentally sustainable development.

SECTION E. Stakeholders' comments

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The proposed 726.6 MW natural gas based combined power plant will be implemented by OTPC. The project will use natural gas as a fuel, which will be supplied by ONGC. The GHG emissions of the combustion process, mainly CO_2, will be substantially less as compared to any other fossil fuel based power plant. The fuel is clean; therefore there is no likelihood of suspended particulates in the stack gases.

The stakeholders identified for the project are as under.

- IL&FS
- ONGC
- Government of Tripura
- Electricity Regulatory Commissions
- Elected body of representatives administering the local area (village Panchayat)
- Statutory environmental and pollution boards of government.
- Non-Governmental Organisations (NGOs)
- Consultants
- Equipment Suppliers/Contractors

Stakeholders list includes the government and non-government parties, which are involved in the project at various stages. OTPC applied / communicated to the relevant stakeholders to get the necessary clearances.

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

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OTPC had conducted a stakeholder consultation meeting in an open and transparent manner on 10 March 2010 to create awareness among the stakeholders. They had invited all identified stakeholder explaining clearly about the project and sought their view on the project. The meeting was attended by the representatives of the identified stakeholders. No adverse comment was received on the said power plant. A brief description of the issues raised by the stakeholders and the corresponding explanation by the project participants are described in brief in section E.2.






E.2. Summary of the comments received:

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Presented below in brief the issues raised by the stakeholders and the clarification provided by project promoters.

Shri Ranjit Paul Choudhury, Head Project, (Head Project, OTPC), welcomed the participants to the Meeting. Mr. Alok Mukherjee, (Director & CEO, OTPC) addressed the gathering and explained the purpose of the meeting. He appraised the gathering about the essentials of the project and its relevance for the region. He also informed the gathering about the global warming and its menace and how the said project would be beneficial to the environment and its importance for sustainable development of the locality.

Mr. Amit Kumar, (GM (P), ONGC) in his address, explained the importance of the gas based power project for the region and its utility for sustainable development.

Mr Rajat Majumdar, village head Palatana enquired about the water requirement for the project and its likely impact on the water level of the Gomti river. Mr Ranjit Paul Choudhury satisfactorily answered his query. Mr Subhash Debroy, Village Head nimpara village and Ms Shipra Majumdar, Chairperson Gram panchayat samity, raised issues related to the sustainable development of the project. Mr Alok Mukherjee and Mr Ranjit Paul Choudhury replied to their queries satisfactorily. Mr Sumanta Chakraborty, Executive Engineer, Tripura State Pollution Control Board, hailed OTPC's effort for the project and assured the gathering about its favourable environmental, societal and financial impacts over the region.

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

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There were no adverse comments received from the stakeholders and the beneficial effects of the project activity were acknowledged by the stakeholders present.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

There is no public funding involved in the proposed project activity. The total investment in the project has been accrued from internal sources.

Annex 3

BASELINE INFORMATION

The Central Electricity Authority (CEA) under the Ministry of Power, Government of India, has estimated the Operating Margin, Build Margin and Combined Margin emission factor for the NEWNE grid, the details of which are available on the following website:
http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

The procedures and formulas used for estimation of the baseline factor and the assumptions made have also been detailed in there.

Annex 4

MONITORING INFORMATION

The monitoring plan has already been discussed in detail in Section B.7.2

Appendix 1

Action plan for expenditure on Sustainable Development

In keeping with the requirement of the NCDMA, OTPC shall commit a minimum of 2% of the annual CDM revenue from the project activity towards sustainable development including society/community development at the local level of the project. OTPC shall monitor the progress of these activities through its Corporate Social Responsibility (CSR) group. The activities proposed to be carried out in future are as follows:

- Training on weaving/ tailoring for ladies from weaker section
- Formation of Self Help Groups (SHGs)
- Marketing support for sustainable income generation
- Ground Water Re-charging
- Infrastructure facilities at schools
- Training to unemployed youth
  - Dress making
  - Driving
  - Computer applications
- Construction of community halls in each village
  - Skill development
  - Vocational training
  - Production center for the inhouse products
  - Social functions
  - Awareness programmes

The Project is expected to generate 1,612,506 CERs per annum upon registration. However, the net realization that is likely to accrue to OTPC from selling CERs would be based on actual energy generation and prevailing market price for CERs after meeting statutory tax requirements. OTPC shall commit 2% of this realisation towards community development activities.

If the activities undertaken involve capital expenditure exceeding the minimum requirement of 2%, the additional expenditure made would be set off against the requirements for the subsequent years. Such expenditure would be made within one year after the realization of revenues from the sale of the CERs. The details of such expenditure made would be included in the monitoring report for the period following the transaction. The same can be verified through the Annual Report of the Company/ a certificate from the statutory auditor/ a certificate from a Chartered Accountant.

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