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

CONTENTS

SECTION A. General description of project activity

A.1 Title of the project activity:

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Title: "100 MW Malana – II, Hydro – Electric Power Project (Malana – II HEP)" at Kullu district of Himachal Pradesh State, India, by M/s Everest Power Private Limited.

Version: 11
Date: 28/ 10/ 2009

A.2. Description of the project activity:

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The Malana – II Hydro Electric Power Project is a Run-of-the-river Hydro Power project, located in the Malana Nallah, a tributary of Parbati River in the Beas Basin, near the Malana village of Kullu District, State of Himachal Pradesh, India. The purpose of the project activity is to supply clean and environment friendly power to feed the Northern Region Grid (NR Grid). The electricity to be generated will be replacing the thermal energy dominated Grid Power in the NR Grid by environment friendly hydro power and will improve the supply quality of power.

This Project envisages an exploitation of hydro power potential in the upper reaches of Malana Nallah, to produce environment friendly power with Run-of-the-river technology to feed up the NR Grid of India. The Malana-II hydroelectric project is proposed to generate (2 x 50) 100 MW of power, with an energy generation of 428 GWh (Equivalent to 428, 000 MWh/ year) at 90% dependable year. The proposed project will develop a concrete gravity dam of 45 m height, above the river bed, which will serve as diurnal storage of about 0.2875 Million cum, with an area of submergence of 3.5 hectare. The power density of the project is calculated 2857 watt/m^2.

Contribution towards Sustainable Development:

- The proposed project will employ approximately 800 people during the construction stage and 100 people during the operation stage. Most of the labour forces, except the very skilled and technical labour, will be comprised from the local habitat. This will help in employment generation and poverty alleviation in the remote region.
- The project will facilitate development of communication infrastructure like Road, Telecommunication, Post-office, Medical Camp, Training centres etc. in the area, which will improve the economical index and help in livelihood generation.
- The power generation from the project activity will be used by the State / Region, to enhance the access of power to the remote villages like Malana, help in developing small / cottage industries and stop rural to urban migration.
- This project will conserve conventional resources like coal/gas/oil and will promote renewable primary natural resources, thus addressing the energy security of India.
- The project will help in land price appreciation; hence will provide benefits to the landowners and local community.
- The project activity will help in mitigating the substantial energy & peaking power deficit in the NR Grid, through environment friendly technology.

- The generated electricity from the project will help in reducing the carbon intensity in Indian power sector.
- Successful implementation of the project will attract the business sectors & Financial Institutions and will enhance their participations in similar types of projects.
- The project being Run-of-the-river hydro with small diurnal reservoirs, will be having minimum impacts on the local environment and the community living around.
- The project developers proposed to take up substantive plantation activities which will further contribute to enhance the environmental and economical well being of the area.
- A detailed Environmental Impact Assessment (EIA) and Environmental Management Plan (EMP) has been prepared and approved by the Ministry of Environment & Forests, Government of India, with sufficient, planned measures to mitigate the whatsoever small environmental impacts which may take place during the construction and operation of the project.
- Highly efficient vertical axis Pelton turbine and generators are being used in the project and further the power transmission will be at high voltage to ensure low losses.

A.3. Project participants:

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Please refer to the Table A.1 below:

Table A 1: Parties Involved in the Project

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)	Private Entity: Everest Power Private Limited (EPPL)	No
(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party (ies) involved is required.		

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

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Country:	India
State:	Himachal Pradesh
River:	Malana Nallah, a tributary of Parbati River in the Beas Basin.
Vicinity:	Weir site located in Malana valley (3 Km upstream of Malana village) at EL $\pm$ 2500 m and Power House on the left bank of Malana Nallah, at EL $\pm$ 1910 m.
Location:	Latitude – between $32^0$5’06” N to $32^0$02’15” N Longitude – between $77^0$16’51” E to $77^0$15’26” E

A.4.1.1.	Host Party (ies):

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India

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

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Region:	Northern India
State:	Himachal Pradesh
District:	Kullu

A.4.1.3.	City/Town/Community etc:

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Village:	Malana Village (3 km)

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

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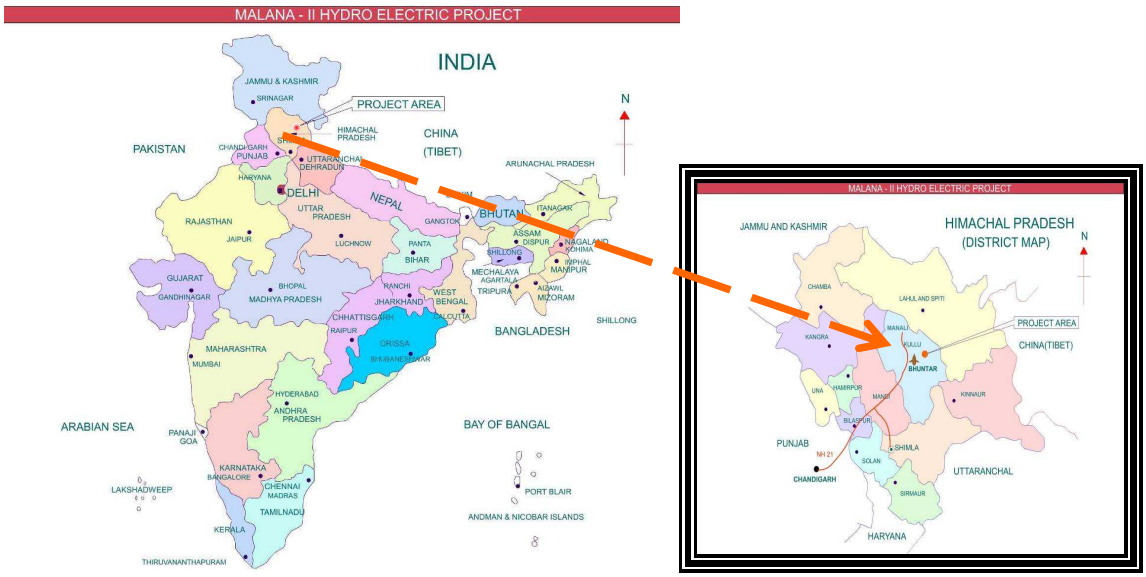
The 100 MW Malana – II Hydro Electric Power Project (Malana – II HEP) is located in District Kullu of Himachal Pradesh and envisages exploitation of Hydro Power Potential in the Upper Reaches of Malana Nallah, a tributary of the Parbati River which in turn flows into Beas River below Bhunter. The project site is approached by road about 10 Km from Jari Village on Bhuntar Manikiran road at a distance 22 Km from Bhunter. The nearest rail head is Kiratpurshahib about 200 Km from the project site. There is an air field at Bhunter, about 22 Km from project site. The details of the physical location of the project are shown below:

Location



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

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100 MW Malana – II Hydroelectric Project is a run-of-the-river hydro – electric power project, and categorized in Scope 1, Sectoral Scope: Energy Industries (renewable / non-renewable sources).

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

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The main component of the project comprises a concrete gravity dam of 45 m high. A 3 m dia and 100 m long intake is there from the non overflow section of the dam to Desilting Basin. A surface Desilting Tank, of size 8 m x 6 m and 130 m long, has been designed to exclude silt particles down to 0.2 mm size. A 3 m x 2.75 m D shaped, (+/-) 4.847 Km long Head Race Tunnel (HRT) on the left bank of Malana Nallah, designed to carry 20 cumecs discharge at 2.75 m/sec velocity. An underground surge shaft with 6 m dia and 90 m depth is there at the end of HRT and a Valve chamber of size 6 m x 10 m x 10 m is located between the Surge Shaft and the Pressure Shaft for emergency closure of the flow. A single Pressure Shaft of 2.5 m dia and (+/-) 646 m long, designed to carry 20 cumecs discharge into the Power House. An underground Power House, of size 20.25 m wide, 68 m long and 31 m high on left bank of the Malana Nallah, exists with two nos. of Vertical Axis Pelton wheel driven generating units of 50 MW each, with an energy generation capacity of 428 GWh (Equivalent to 428, 000 MWh/ year) at 90% dependable year.

The power generated would be evacuated through one double circuit 220KV transmission line taking off Malana-II HEP and fed into 400KV substation of Power Grid Corporation of India Limited (PGCIL) at Panarsa. The power would be further transmitted to other states of Northern Region through Power Grid/ respective state transmission systems. Power Line Carrier Communication (PLCC) system would be established between Malana-II HEP and Parbati's PGCIL substation. In line with the modern practice, each of the 220KV transmission lines will be provided with high speed distance protection as primary protection and back up protection as well. Some part of the transmission line would be passing through the area which experience snowfall in the winter season. This part of the transmission line would be suitably designed considering snow loading. The length of the transmission line between Malana – II and Panarsa PGCIL substation is expected to be about 38 km.

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

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The emission reduction crediting period selected as a single span of ten years. The project is expected to start generation by April, 2009 and likely to reduce 345, 622 tonnes of $CO_{2\,e}$ per year over the crediting period 2009 to 2019. This value is based on the projected power generation of 428 GWh / year (Equivalent to 428, 000 MWh/ year) and a Combined Margin emission factor of 0.80753 t CO_2 / MWh.

Table A 2: Emission reductions during the crediting period

Year	Annual Estimation of Emission Reduction in tones of CO_2 Equivalent
2009	345, 622
2010	345, 622
2011	345, 622
2012	345, 622
2013	345, 622
2014	345, 622
2015	345, 622
2016	345, 622
2017	345, 622
2018	345, 622
Total Estimated Reduction (tonnes of $CO_{2\,e}$)	3,456,220
Total Number of Crediting Years	10 Years
Annual average over the crediting period of estimated reductions (tonnes of CO_2e)	345, 622

A.4.5. Public funding of the project activity:

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The project is not utilizing any public funding from Annex I Countries. Only term loans from various Indian Financial Institutions and banks have been received for the project activity. The total project cost is INR 5,988 Million with a debt equity ratio of 70:30. The contributions of loan have been received from Rural Electrification Corporation (REC), State Bank of Patiala and Punjab National Bank. All the above funds do not create any diversion of Official Development Assistance (ODA).

SECTION B. Application of a baseline and monitoring methodology

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

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The baseline methodology selected for this project is

Title:	"Consolidated baseline methodology for grid-connected electricity generation from renewable sources"
Sectoral Scope:	1
Reference:	ACM 0002
Version:	"Version 07", 14th December, 2007.

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

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As specified in the methodology ACM0002, Version 07, of 14th December, 2007, in the "Applicability" Section, this project is applicable under the following conditions:

Applicability Conditions in the ACM0002/Version 07	Position of the project activity
Applies to electricity capacity additions from: Run-of- river hydro power plants; hydro power projects with existing reservoirs where the volume of the reservoir is not increased.	The project activity is a grid connected run-of-the-river hydro power project
New hydroelectric power projects with reservoirs having power densities (installed power generation capacity divided by the surface area at full reservoir level) greater than 4 $W/m^{2.}$	The project is ideally addressing the point; being a totally new project of 100 MW capacity, with diurnal storage, resulting 3.5 hectare of submergence at the Full Reservoir Level (FRL), with power density 2857 Watt / m^2, which is much above the specified lower limitation of 4 Watt / m^2. The project activity also envisages using the approved monitoring methodology of ACM 0002, as stipulated in the provision of ACM0002, Version 07, 14th December, 2007.
This methodology is not applicable to project activities that involve switching from fossil fuels to renewable energy at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels at the site;	It is a renewable energy project with no fuel-switch involved.
The geographic and system boundaries for the relevant electricity grid can be clearly identified and information on the characteristics of the grid is available;	The project activity supplies power to NR Grid of India which manages the supply of electricity among the Northern States of India. It is connected to all the power plants supplying power to the state grids of Delhi, Haryana, Himachal Pradesh, Jammu & Kashmir, Punjab, Rajasthan, Uttar Pradesh, Uttaranchal and Union Territory of Chandigarh. Adequate data and information are available to estimate the grid emission factor. Central Electricity Authority (CEA) of India, has already compiled and published *"CO_2 Baseline Database of Indian Power Sector"* and whose

	latest version 3.0 has been out for public consumption on December 15, 2007.

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

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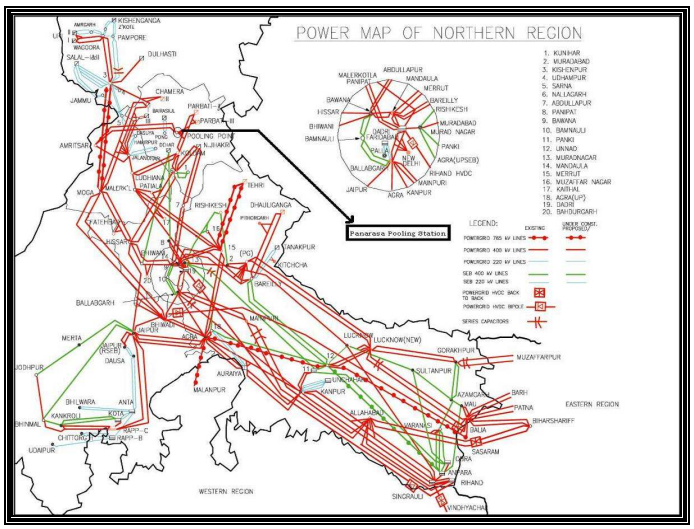
As per the instruction provided in the Consolidated Methodology ACM 0002, Version 07, 14th December, 2007, for the baseline emission factor, the spatial extent of the project boundary includes the project site and all power plants connected physically to the electricity system that the CDM project power plant is connected to and the project will account only the following emission sources for the project activity:

1. As the project does not consume any fuel in its operation the project is not having any Greenhouse Gas (GHG) emission from its operation.

2. The project has a diurnal storage (storage capacity for 4 hrs) concrete gravity dam, which will create a submergence of 3.5 hectare. The submergence area is having a vegetation cover, with species like Rai, Tosh, Chimmu, Mapple Kail, Khanor, Walnut, Moharu, Jammu Popular, Tharbal etc. Total 91 trees in these species category will be cut before the submergences and an compensatory afforestation as proposed in the Environment Management Plan (EMP), approved by Ministry of Environment & Forest, Government of India. Total 62.6 hectare of degraded land will be taken for new plantation which will materialize development of fresh forest amounting more than 93 thousand trees in major species categorization. It is also proposed to develop greenbelt around the periphery of various project activities along with the reservoir periphery. About 1100 trees per hectare are to be planted. The maintenance of the plantation area will be also be done by the project proponent. The above information establishes that the emission of GHGs like Carbon-di-oxide (CO2) and Methane (CH4) due to enumerations of 91 trees and the submergences, will be many fold compensated by the afforestation activity by the project proponent.

	Source	Gas	Included?	Justification/ Explanation
Baseline	Grid electricity generation in Baseline	CO_2	Yes	Main emission source
		CH_4	No	Excluded (conservative approach)
		N_2O	No	Excluded (conservative approach)
Project Activity	Emission of CH_4 from the reservoir	CH_4	No	Excluded as power density factor is 2857 Watt / m^2

Northern Region Grid Layout:



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

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As the project is a New, Grid connected Hydroelectric Project (HEP), the Baseline Methodology applied is ACM0002, Version 07, of 14th December, 2007, "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" and the baseline is defined as: "Electricity delivered to the grid by the project would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources."

During the project planning stage, NR Grid was facing substantial power shortage and at present also, there is a gap between the demand – supply scenario in the Northern region. As per the agenda of Ministry of Power (MoP), Government of India, to provide power to all by the year 2012 and to meet the national power deficit of 12.2 %, new capacity needs to be added to the existing installed capacity.
(Source:http://www.cea.nic.in/planning/POWER%20SCENARIO%20AT%20A%20GLANCE/POWER%20SCENARIO%20AT%20A%20GLANCE.pdf).

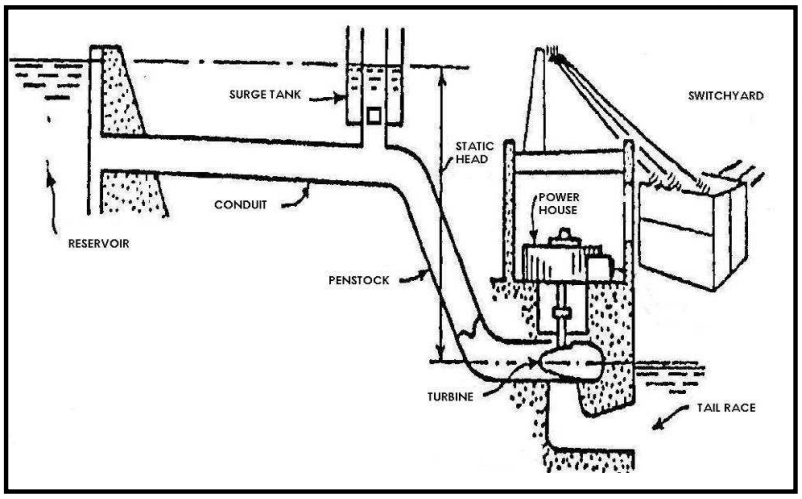
To push forward the power sector reforms further, the Government of India has opened up the coal sector for private participation. Captive coal mining is allowed by the Ministry of Coal to facilitate coal mining by power generating units for their fuel needs. In addition, coal imports are allowed for power projects. This has significantly strengthened the preference of the private sector investors for coal-based mega power projects compared to other energy sources. Therefore, to compensate the power demand supply gap, there is an emphasis on coal based power projects, hence, maximum of present and future capacity addition will be possibly based on coal.

Thus, the present grid mix will continue with the existing power plants connected to the NR Grid, which are mainly fossil fuel based power projects (mainly coal). This option will not reduce the GHG emissions from the grid but is likely to exist as the most plausible alternative in the absence of the project activity, hence can be considered as the baseline scenario for the

proposed project. Detailed analysis of the selection of the baseline scenario has been done in section B.5. as per which , the baseline scenario for the project is the continued generation of power from all the (grid connected) power plants of the NR Grid of India. According to the methodology ACM0002 Version 07, the baseline emissions are the amount of electricity produced times the grid emission factor which is the Combined Margin (CM), calculated as the simple average of the Operating Margin (OM) emission factor and the Build Margin (BM) emission factor.

The electricity transmission & distribution system in India are divided into five regions, Northern, Southern, Eastern, Western, and North Eastern. This project is connected to the Northern Regional Grid, which comprises of the states Delhi, Haryana, Himachal Pradesh, Jammu & Kashmir, Punjab, Rajasthan, Uttar Pradesh, Uttaranchal, and Union Territory of Chandigarh, which shares the Grid Power generated in the area through NR Grid. This network also obtains proportions of the electricity from the Central sector.

Physical Layout of the Project



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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In the absence of the project activity, an equivalent amount of electricity would be produced by other power plants in the NR Grid of India. The baseline scenario is therefore, increased rate of thermal generation in the NR Grid, as this grid is heavily dominated by coal-fired stations, contributing 60.3 % (and total thermal contribution is 71.86 % ~ 72%) of the total generation with a trend towards further increase (Source: www.cea.nic.in). Consequently, the project activity results in displacement of a carbon-intensive grid-mix through generation of electricity using a renewable source. Hence, it is clearly indicated that the emission reductions would not occur in the absence of the project activity.

Additionality:

The project activity is additional compared to the baseline scenario, which is discussed by using the "Tool for the demonstration and assessment of additionality - version 05.2" in the following paragraphs:

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

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

The alternatives available for this project activity which are realistic, credible and provide outputs comparable with this activity are

1. The project activity not undertaken as a CDM project;
2. A gas based power project with equivalent power output;
3. Power generation technology using wind, biomass, geo-thermal etc;
4. Continuation of the current situation in the Northern Grid with no project activity or alternatives undertaken and through its currently running power plants (which are mostly thermal) and or by new capacity addition to the grid;

Alternative 1: The project activity not undertaken as a CDM project

As the project is not financially attractive without CDM consideration, as discussed in the investment analysis, this alternative cannot be undertaken without CDM consideration.

Alternative 2: A gas based power project with equivalent power output

This alternative can meet the same load output in comparison with the proposed project activity but with a higher GHG emission contributing towards the grid. But, due to insufficient gas availability, lack of supply infrastructure and huge uncertainty of gas price and its dependency on the vulnerable International Crude Oil market, this cannot be considered as a feasible and realistic alternative. Further, during the planning stage of the proposed project, gas accessibility was not sufficient in the Northern region. New gas pipelines are being planned to set up presently in the Northern region by GAIL and other suppliers, which will be having its own

gestation time and will not be available with immediate effect, which further illustrates the non – feasibility of the gas projects in the Northern region during the planning stage of the proposed project *(Source: Ministry of Petroleum and Natural gas) (http://petroleum.nic.in/ng.htm).*

Therefore, Gas based power projects cannot be considered as a realistic alternative in the Eastern and Northern region during the planning stage of the project.

Alternative 3: Power generation technology using wind, biomass, geo-thermal etc.

Wind and Biomass power projects cannot be considered as realistic plausible alternatives for such large scale of power generation.

Biomass plants are mainly small scale plants and not comparable with large scale plants like the project activity. In the Northern region, there is no commercial grid connected biomass based plant till date as per CEA database (Source: http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm). Again, Bagasse is the main biomass-fuel available for power generation in the region whose availability is seasonal and does not have an organised market. Therefore, it can be concluded that biomass based power generation units cannot be considered as realistic alternative for the proposed project activity.

Though wind speed required for power generation is available in the western part of the Northern Grid but because of the intermittent nature of wind and resulting low Capacity Utilization factor, such large scale power generation from wind projects cannot be considered as realistic alternative for the proposed project activity (Source: WPD Map; http://www.cwet.tn.nic.in/html/departments_wpdmap.html).

In case of Geo-thermal technology base power projects, it is still not a proven technology in India till date as no commercially operating project is there. (Source: http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm).

Alternative 4: Continuation of the current situation in the Northern Grid with no project activity or alternatives undertaken and through its currently running power plants (which are mostly thermal) and or by new capacity addition to the grid

In this scenario, the present grid mix will continue with the existing power plants connected to the NR grid, which are mainly fossil fuel based power projects. This option will not reduce the GHG emissions from the grid but is likely to exist as the most credible and realistic alternative in the absence of the project activity.

During the project planning stage, NR Grid was facing substantial power shortage and at present also, there is a gap between the demand – supply scenario in the Northern region. As per the agenda of Ministry of Power (MoP), Government of India, to provide power to all by the year 2012 and to meet the national power deficit of 12.2 %, new capacity needs to be added to the existing installed capacity.
(Source:http://www.cea.nic.in/planning/POWER%20SCENARIO%20AT%20A%20GLANCE/POWER%20SCENARIO%20AT%20A%20GLANCE.pdf).

To push forward the power sector reforms further, the Government of India has opened up the coal sector for private participation. Captive coal mining is allowed by the Ministry of Coal to facilitate coal mining by power generating units for their fuel needs. In addition, coal imports are allowed for power projects. This has significantly strengthened the preference of the private sector investors for coal-based pit head mega power projects compared to other energy sources. Therefore, to compensate the power demand supply gap, there is an emphasis on coal based power projects, hence, maximum of present and future capacity addition will be possibly based on coal.

In line with the Five Year Plan system being followed by the Planning Commission of India, the Ministry of Power (MoP) decided to add about 46,000 MW during the period 2002-2007 and about 61,000 MW during the period 2008-2012. Emphasis has been laid on setting up mostly thermal projects with large pithead stations to avoid high costs associated with transporting high ash bearing Indian coal and over-straining the already stretched rail network (www.cea.nic.in).

Thus, the present grid mix, which is dominated by fossil fuel based (mainly coal) power generation, will continue with the existing power plants connected to the Northern grid. This option will not reduce the GHG emissions from the grid but is likely to exist as the most realistic alternative in the absence of the project activity.

Outcome of Step 1a:

From the above discussions, it is clear that the realistic and credible alternative option to the project activity, i.e. the baseline scenario is:

Alternative 4 – Continuation of the current situation in the Northern Grid with no project activity or alternatives undertaken and through its currently running power plants (which are mostly thermal) and or by new capacity addition to the grid.

Sub-step 1b. Consistency with mandatory laws and regulations:

The alternatives mentioned above are in compliance with all mandatory applicable laws and regulations and are in no way violating any applicable legal and regulatory requirements.

Outcome of Step 1b:

The above identified realistic and credible alternatives to the project activity are in compliance with mandatory legislation and regulations taking into account the enforcement in the region and the country and EB decisions on national and/or Sectoral policies and regulations.

Step 2. Investment analysis

The proposed project activity is not as much economically or financially attractive than other identified alternatives due to the risks associated, such as; the project activity comes under Seismic Zone IV, therefore, installation of civil structure in such hilly region creates substantive amount of uncertainty. To make the civil structure earthquake resistant, an additional investment is highly essential which makes the project capital intensive. As there is no approach infrastructure to the project site, development of the overall infrastructure and communication facilities in the project site causes an additional amount of investment.

Sub-step 2a. Determination of appropriate analysis method

According to the "Tool for the demonstration and assessment of additionality - version 05.2", the Sub-step 2b. – Option III. Apply benchmark analysis has been followed for additionality analysis.

As per EB 41 report, Annex 45, "Guidance on the Assessment of Investment Analysis", (Version 02), point 15, page no. 4), if the proposed baseline scenario leaves the project participant no other choice than to make an investment to supply the same (or substitute) products or services, a benchmark analysis is not appropriate and an investment comparison analysis shall be used. If the alternative to the project activity is the supply of electricity from a grid this is not to be considered an investment and a benchmark approach is considered appropriate.

The purpose of an investment analysis in the context of the CDM is to determine whether the project is less financially attractive than at least one alternative in which the project participants could have invested. In cases where the alternative requires investment anyhow and baseline emissions are based on that alternative, the only means of determining that the project activity is less financially attractive than at least one alternative is to conduct an investment comparison analysis. The benchmark approach is therefore suited to circumstances where the baseline does not require investment or is outside the direct control of the project developer, i.e. cases where the choice of the developer is to invest or not to invest. In case of this project activity, the baseline scenario is the continuation of the current situation in the Northern Grid with no project activity or alternatives undertaken and through its currently running power plants (which are mostly thermal) and or by new capacity addition to the grid. Therefore, benchmark analysis has been followed for additionality analysis.

The Prime Lending Rate (PLR) as recorded by Reserve Bank of India's Cash Reserve Ratio and Interest Rate statements, represent the average prevailing lending rate of major banks and financial institutions in India. During the financial closure of the project (during the time of Common Loan Agreement execution) the PLR has been recorded as 11.00% to 11.50% by Reserve Bank of India (*Source: Reserve Bank of India; webpage: http://www.rbi.org.in/Scripts/WSSView.aspx?Id=10371)*. The project Management, during the Financial Closure of the project, has been able to negotiate the Commercial Lending Rate (CLR) of 11.25% from Punjab National Bank, 10.5% from State Bank of Patiala (SBoP) and 10.5% from Rural Electrification Corporation limited (REC). Considering the most conservative CLR of 10.5%, i.e. CLR of SBoP and REC, which is also conservative in comparison to the prevailing PLR, has been taken as Benchmark for Investment Analysis. Therefore, for investment analysis, Sub-step 2b. Option III has been used as referred in the "Tool for the demonstration and assessment of additionality - version 05.2".

Sub-step 2b. – Option III. Apply benchmark analysis

Total cost of setting up of the project is estimated at Rs.5, 988 Millions. The project is funded by way of term loan to an extent of 70% and share capital to an extent of 30%. The Project IRR, calculated as per the EB 41, Annexure 45, "Guidance on the Assessment of Investment Analysis", without CDM revenue is 10.41. The Project IRR has been increased to 12.26 % considering CDM revenue. This is compared to the benchmark, taken as the Commercial Lending Rate (CLR), as has been recorded in the Common Loan Agreement indicating that CDM revenues enable the project to achieve justifiable return on the investment.

Therefore, it is evident that the Malana – II HEP becomes financially attractive only with CDM revenues. To address this investment hurdle, a Board Meeting was held to consider CDM revenue in a serious manner prior to project implementation to make the project financially attractive. Also, a table has been attached separately as Appendix I showing the CDM consideration at various stages of the project activity as per the "GUIDANCE ON THE

DEMONSTRATION AND ASSESSMENT OF PRIOR CONSIDERATION OF THE CDM" in Annex 46 in EB 41 Report.

Sub-step 2c. Calculation and comparison of financial indicators

The Project IRR of Malana II HEP is 10.41 % without considering the revenue from the sale of CERs, which is lower than the selected benchmark, i.e. Commercial Lending Rate (CLR), as recorded in the Common Loan Agreement of the project activity. The major financial assumptions that have been taken into consideration while calculating the project IRR is as follows:

Assumptions for Investment Analysis:

Particulars	Value	Unit	Assumptions
Unit Capacity	50.00	MW	DPR; Power Potential Studies; P-VI-5
No of Units	2	No	DPR; Power Potential Studies; P-VI-5
Plant Gross Capacity	100	MW	DPR; Power Potential Studies; P-VI-5
Auxiliary Consumption	0.70%	MU	CERC Tariff Guideline
Transformation Loss	0.50%	MU	CERC Tariff Guideline
Transmission Loss	1.00%	MU	CERC Tariff Guideline
Royalty payable to GOHP till year 12	*12.00%*	MU	As per Implementation Agreement
Royalty payable to GOHP afterward	*18.00%*	MU	As per Implementation Agreement
Primary Generation *(90% Dependable Year)* in MU	428.00	MU	As per DPR
Total Energy Generated in MU	428.00	MU	As per DPR
Basic Tax	30%	Basic tax and surcharge	As applicable in Income Tax Rule
Dividend Distribution Tax	15.00%		
Minimum Alternate Tax	10%		
Tax Exemption u/s 80 I	10	Consecutive Years During first 15 Years of Operation	
	6	Start year as assumed in the model	
Interest on Working Capital	12.5%		Market Rate Prevailing during Financial Closure
Annual O&M as a % of Project Cost	1.5%		CERC Tariff Guideline
Annual O&M Escalation	4.00%		CERC Tariff Guideline
Tariff of 1st Five Years	2.64	Rs/kwh	As per Executed PPA
Tariff from 6 to 11 Years	2.47	Rs/kwh	As per Executed PPA
Tariff after 11 Years	2.31	Rs/kwh	As per Executed PPA
Levelised Tariff of Forty Years	2.5	Rs/kwh	As per Executed PPA
Secondary Gen Tariff	0.75	Rs/kwh	As per Executed PPA
Rebate on Bills	2%		As per Executed PPA

Depreciation			CERC Tariff Guideline
Book (90% of the completion cost)	5389	INR Million	
Depreciable Value			
Method of Depreciation 1= SLM; 2=WDV	1		As applicable in Companies Act
Annual Depreciation Rate	2.50%		
Life of the Asset	40	years	As per Implementation Agreement
Method of Depreciation 1= SLM; 2=WDV	2		As applicable in Income Tax Rule
Annual Depreciation Rate	15.00%		

Sub-step 2d. Sensitivity analysis

As per the sensitivity analysis for all the alternatives, considering reasonable variations in the critical assumptions like total annual electricity generation (+/-10%) and Project hard costs (+/-10%), it can be concluded that the Project IRR can marginally achieve the benchmark value in favourable scenario, justifying that the CDM revenue helps the project to become financially attractive from investment perspective.

The variation of Electricity tariff and O & M costs have not been shown in the sensitivity analysis, as the tariff is fixed tariff and the variation of O & M cost is not applicable as per EB 41, Annex 45, Page 4, Sensitivity analysis (Point No. 16).

For variation of the above mentioned parameters by (+/-10), the impact on Project IRR has been shown:

Sl. No.	***Indicators***		***Project IRR***
1.	Base case		10.41%
2.	Total annual electricity generation	(+)10%	10.83 %
		(-) 10%	8.94 %
3.	Project Hard costs	(+)10%	9.06%
		(-) 10%	10.57%

Outcome of Step 2:

From the Investment analysis, it can be clearly shown that the proposed project without CDM consideration is not financially attractive and CER revenue will make it investment friendly and will have a positive impact on project IRR and. Therefore, Step 3 – Barrier Analysis is not required.

Step 4. Common Practice analysis

Sub-step 4a. Analyze other activities similar to the proposed project activity:

Malana- II hydro power project is one of the large hydro power projects in the Northern Grid and is promoted by private developer. The main reason behind the lack of private participation is due to the difficulties in arranging finance for their project due to large amount of uncertainty in the project execution and operation and low rate of return etc.

As per Sub-step 4.a. under Common Practice analysis test, projects are considered similar if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc. Considering all these factors, some projects have been identified in the region, e.g. Vishnu –prayag HEP and Baspa HEP and have been discussed in details under Sub-step 4b (Source: http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm).

Sub-step 4b. Discuss any similar options that are occurring:

The project is located in the lesser Himalayan within the Banjar and Jutogh formations. Due to the extreme complex terrain around the project site, the proposed project is facing major financial burden compared to the other similar projects occurring in the region. The factors that add burden to investment is as follows:

- The dam complex and part of Head Race Tunnel fall within the Kullu and Khamrada member of Jutogh Formation. The Jutogh and the Banjar formation are separated by a regional tectonic feature known as the Jutogh thrust. This project activity comes under Seismic Zone IV. Therefore, installation of equipments for such a project of this type is a very risky affair and very much prone to demolition of civil structure due to earthquakes. Further, the Geo-technical Note (has been attached separately) on the proposed project establishes the complexity of the project.

- The 4.5 km long Head Race Tunnel will go through a 1.5 km very poor tunnelling strata which need higher support for maintaining stability. These will increase the overall project cost.

- The proposed powerhouse is underground in nature. The power house complex will be excavated in very strong rock structure which is abrasive in nature. Drilling in this rock structure will result high wear and tear for drill bits which increases the drilling cost.

- The approach road from the power house to the dam site has been excavated across steep escarpment. All these zones would be unstable during monsoons and will need regular treatment and maintenance.

- The project requires approximately 12 km new motorable road construction to connect the wire and power site. This road also helps the local inhabitant of Malana Village (Total population approx. 2000 people) to get connected with the main stream of the state.

- **Power Evacuation System:**

  This project is located at the hilly region and surrounded by the forest also. The generated power is fed into Power Grid Corporation of India Limited (PGCIL) sub-station at Panarsa. This sub-station is under Northern Grid. The project proponent has to set up 38 Km long, 220 KV transmission line in such hilly region, which automatically produces a burden to the project developer.

- **Power Purchase Agreement:**

  The Power Purchase Agreement the project has executed with Power Trading Corporation (PTC) shows major investment risks has not been passed on and will be borne by the project proponent are as follows:

  - PPA of Malana - II pays tariff which is Minimum of CERC Tariff + Tariff credit and Capped tariff. Under no scenario the project company would recover anything more than CERC tariff. Also, under the present tariff conditions the project company would not recover any amount more than the capped tariff. This may lead to shortfall in cash for maintaining the DSCR requirements, delay in creating the Debt service reserve during the repayment period and also investors of the project will have a long gestation before getting any dividends.

  - Capped tariff is calculated considering the overall completion cost of INR 598 crores with INR 558 crores as hard cost. With the increased interest rates the IDC component of the project is expected to go up and the capped tariff would not be increased to accommodate the same. Also, the PPA does not accommodate any increase in hard cost which may occur on account of any increase in tax rates or any geological surprises or change in scope of works.

  - Any increase or decrease in costs on account of change in law is accommodated in the CERC Tariff but capped tariff will not be modified. At the time of signing of the PPA the MAT rate applicable was 8% and the education CESS was 2%. As on date the MAT rate has been increased to 10% and the Education cess has been increased to 3%.

Higher elevation, extreme difficult terrain, various difficult constructions aspects with maximum underground component has made the project more capital intensive and geological risk prone in comparison with the other similar projects. The other project existing in the region is not facing the above – mentioned risks associated with the project activity and are having advantages like higher head, lesser cost/ MW generation etc. (has been mentioned below).

Project Name	Installed Capacity	Yr. of Comm.	Project Dev.	Cost/MW (INR. in Crores)	Gross Head	Source
Baspa HEP 300 MW	Unit-I 100 MW	24th Jan, 03	Jaiprakash Hydro Power Limited	5.41	702 m	http://www.jhpl.com/pdfs/tariffpetition.pdf http://www.jhpl.com/baspa-techinfo.htm
	Unit-II 100 MW	8th Jan, 03				
	Unit-III 100	27th May,				

	MW	03				http://www.cea.nic.in
Vishnu - prayag HEP 400 MW	Unit-I 100 MW	3rd Jun, 06	JAYPEE Groups	2.96	947.5 m	www.jilindia.com http://www.uttaranchalirrigation.com/hydro/projects_vishnuprayag.htm http://www.cea.nic.in
	Unit-II 100 MW	23rd Jun, 06				
	Unit-III 100 MW	16th Aug, 06				
	Unit IV 100 MW	30th Sep., 06				
Malana I (Merchant Hydro Plant)	86 MW	July, 2001	Malana Power Company Limited (MPCL)	3.75	480 m	http://www.malanapower.com/technical_info.aspx
Malana II HEP	Stage II 100 MW	April, 2009	Everest Power Private Limited (EPPL)	5.98	626 m	N/A

Another large scale hydro project from the same region, registered as a CDM project (Project Reference No. : 0862, Allain Duhangan Hydroelectric Project (ADHP)), further establishes that without CDM revenue, Malana II HEP is not financially attractive.

Hence, all the steps to address the Additionality tool – Version 05.2 have been satisfied.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

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The project activity is a run-of-the-river hydro electric project with reservoir, located in the state of Himachal Pradesh of India and will supply power to the Northern Regional (NR) Grid of India, which is highly dominated by thermal power plants with further plans for fossil fuel based generating projects.

Therefore, the applicable baseline is "Consolidated Baseline Methodology for Grid-connected electricity Generation from Renewable Sources" - ACM 0002 / Version 07/ Sectoral Scope 1, December 14, 2007". To calculate the emission factor, the "CO_2 Baseline Database of Indian Power Sector", version 03. 15th December, 2007, published by Central electricity Authority (CEA), Government of India, has been used, which is based on the "Tool to calculate the emission factor for an electricity system" *(Source: http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm).*

Application of Baseline Methodology

The following six steps have been followed as per "Tool to calculate the emission factor for an electricity system":

STEP 1. Identify the relevant electric power system.
STEP 2. Select an operating margin (OM) method.
STEP 3. Calculate the operating margin emission factor according to the selected method.
STEP 4. Identify the cohort of power units to be included in the build margin (BM).
STEP 5. Calculate the build margin emission factor.
STEP 6. Calculate the combined margin (CM) emissions factor.

STEP 1. Identification of the Relevant Grid System

The Indian power system is divided into five independent regional grids, namely Northern, Eastern, Western, Southern, and North-Eastern as mentioned below as per CO_2 Baseline Database for the Indian Power Sector User Guide, Version 3.0, December 2007, Central Electricity Authority, Ministry of Power, Government of India.

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

The project activity is located at Himachal Pradesh, which comes under Northern Grid of India. Therefore, Northern Grid has been used as the reference grid system for estimating the baseline emission.

STEP 2. Selection of an operating margin (OM) method

For calculation of operating margin four options are available:

Option 1. Simple operating margin;
Option 2. Simple adjusted operating margin;
Option 3. Dispatch data analysis operating margin;
Option 4. Average operating margin.

CO_2 Baseline Database, Version 3, 15th December, 2007, published by Central Electricity Authority (Source: http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm.) has been referred for the values of Operating Margin. As per the "Tool to calculate the emission factor for an electricity system" (Version 01), any of the four methods can be used, however, the simple OM method can be used only if the low-cost/must run resources constitute less than 50% of the total grid generation in: 1) average of the five most recent years, or 2) based on long term averages for hydroelectricity production.

The amount of power supplied by low cost/ must-run power plants to the Northern Regional Grid in the last three years ranges from 26% to 29% and is clearly below 50%. Therefore, the **Simple OM method** has been opted.

Selected Years	2004-05	2005-06	2006-07
Low cost/ must-run power plants to the Northern Regional Grid	26.8%	28.1%	27.1%

(Source: CO_2 baseline database published by Central Electricity Authority; Source: http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm.)

STEP 3. Calculation the operating margin emission factor according to the selected method

The Central Electricity Authority (CEA) of India has published the official emission factors for all regional grids in India, in order to facilitate CDM project and offer consistent data for all project developers. Application of this officially published database represents the most accurate approach, and hence, has been applied in this project activity.

As per the "Tool to calculate the emission factor for an electricity system" (Version 01), the calculation of OM has been done as per ex - ante based approach on the basis of most recent 3 years data as available at the time of PDD submission.

Table B 1: Average Operating Margin (OM)

Selected Years	2004-05	2005-06	2006-07
Operating Margin (OM) in tonnes CO_2 / MWh	0.97448	0.99365	0.99202
Average of the Three years in t CO_2 / MWh	0.98672		

(Source: *Carbon Dioxide Baseline Data base, Version 3,* 15th December, 2007*;* http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm)

STEP 4. Identification of the cohort of power units to be included in the build margin (BM)

The Build Margin emission factor has been considered as per fixed ex ante approach, based on most recent information available on plants already built at the time of PDD submission. This simplifies the monitoring procedures and offers a conservative approach of BM calculation.

STEP 5. Calculation of the Build Margin Emission Factor

The officially published database by Central Electricity Authority (CEA) has been used for Build Margin Emission Factor, which reflects best and accurate practice *(Source: Carbon Dioxide Baseline Data base, Version 3,* 15th December, 2007*;* http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm.)

Build Margin (BM)	0.62834 tonnes CO_2 / MWh

STEP 6. Calculation of Combined Margin (CM) Emissions Factor - Emission factor for the Grid electricity

The baseline emission factor in year y is calculated as the simple average of the OM and BM emission factors, i.e. OM and BM are each weighted with 50%. As noted above, the resulting Combined Margin is fixed ex ante for the duration of the crediting period:

$EF_y = W_{OM} \times EF_{OM, y} + W_{BM} \times EF_{BM, y}$

Where
- EFy Combined Margin Emission Factor determined above
- W_{OM} Weight Operating Margin
- $EF_{OM, y}$ Operating Margin Emission Factor
- W_{BM} Weight Build Margin
- $EF_{BM, y}$ Build Margin Emission Factor

Combined Margin (CM)	0.80753 (For Northern Grid)	tonnes CO_2 / MWh

Calculation of the Baseline Emission

The baseline emission in year y is calculated as:

BEy = EFy x EGy

Where
- BEy is the baseline emission for the year y (Combined Margin)
- EGy is the electricity generation by the project activity in year y,
- EFy is the baseline emission factor determined above.

Calculation of the Project Emissions (PEy)

With the reference of the installed capacity ($Cap_{BL;}$ the value is zero, as this is a new power project) of the hydro power plant before implementation of the Malana-II hydro-electric project, the project emission has been considered as zero.

The project being a new project of 100 MW capacity with diurnal storage, resulting 3.5 hectare of submergence at the Full Reservoir Level (FRL), therefore, the power density that has been estimated is as follows:

Total project capacity (MW) =100

Total Submergence Area at Full Storage (hectare) = 3.5

Power Density (watt/m^2) = 100 MW/ 3.5 hectare

$$= \frac{100 \text{ X } 1000 \text{ X } 1000 \text{ W}}{3.5 \text{ X } 10,000 \text{ m}^2}$$

= 2857 Watt / m^2, which is greater than 10 W/m^2.

Hence, PEy = 0 as per the methodology ACM 0002, Version 07, Sectoral Scope 1, December 14, 2007; page no. 8/19; hydro power plants (b). In line with this, there is no requirement of monitoring of the total electricity produced by the project activity, including the electricity supplied to the grid and the electricity supplied to internal loads, in year y (MWh), i.e. TEGy during the crediting period (Please refer to the calculation of the power density in the methodology ACM 0002 / Version 07/ Sectoral Scope 1, December 14, 2007; page no. 8/19; Hydro power plants; (b). Therefore, TEGy has not been incorporated in the data and parameters monitored under the monitoring methodology.

Leakage (LEy):

As per the methodology ACM 0002, Version 07, Sectoral Scope 1, December 14, 2007 (page no. 10/19; Leakage), no leakage has been applied for the project activity.

Hence, LEy = 0.

Calculation of Emission Reduction

The project activity reduces carbon dioxide through substitution of grid electricity generation with fossil fuel fired power plants by generation of electricity using a renewable source. The emission reductions for a given year are calculated as baseline emissions minus the project emissions and leakage:

ERy = BEy – PEy – Ly

Where ERy is the Emission Reduction for the year y
BEy is the baseline emission for the year y (Combined Margin)
PEy is the Project Emissions
Ly is the Leakage

As per the latest version of the methodology used, ACM0002, version 07, 14th December, 2007, (page no. - 8), if the power density (PD) of the power plant is greater than 10 W/m^2, the project Emission will be zero. As the power density calculated for the project is calculated as 2857 watt/m^2, greater than 10 W/ m^2, the project emission has been taken as zero. The leakage (Ly) has also been taken zero as mentioned above as per the methodology. Therefore the emission reductions (ERy) are equal to the (BEy) baseline emissions.

ERy = BEy = EFy x EGy (As PEy = Ly = 0)

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

Data / Parameter:	EFy
Data unit:	tCO_2/ MWh
Description:	CO_2 emission factor of the grid
Source of data used:	Baseline Carbon Dioxide Emission Database/ Version 3.0 dated 15th December, 2007, as published by Central Electricity Authority of Government of India
Value applied:	0.80753
Justification of the choice of data or description of measurement methods and procedures actually applied :	Information available from Central Electricity Authority of Government of India has been used. The same is calculated as a weighted sum of Operating margin emission factor and Build Margin emission factor as per the methodology of ACM0002. Recording frequency – Once at the time of the submission of PDD.
Any comment:	Total data is archived both electronically and on paper.

Data / Parameter:	EF_{OM},y
Data unit:	tCO_2/ MWh
Description:	CO_2 Simple Operating Margin emission factor of the grid
Source of data used:	Baseline Carbon Dioxide Emission Database/ Version 3.0 dated 15th December, 2007, as published by Central Electricity Authority of Government of India
Value applied:	0.98672
Justification of the choice of data or description of measurement methods and procedures actually applied :	Calculated based on the 3-year average data, available at the time of the PDD submission. Recording frequency – Once at the time of PDD submission.
Any comment:	Total data is archived both electronically and on paper.

Data / Parameter:	EF_{BM},y
Data unit:	tCO_2/ MWh
Description:	CO_2 Build Margin emission factor of the grid
Source of data used:	Baseline Carbon Dioxide Emission Database/ Version 3.0 dated 15th December, 2007, as published by Central Electricity Authority of Government of India
Value applied:	0.62834
Justification of the choice of data or description of measurement methods and procedures actually applied :	Information available from Central Electricity Authority of Government of India has been used. The Build Margin emission factor is based on the most recent information available on plants already built at the time of PDD submission. Recording frequency – Once at the time of the PDD submission.
Any comment:	Total data is archived both electronically and on paper.

Data / Parameter:	Cap_{BL}
Data unit:	W
Description:	Installed capacity of the hydro power plant before implementation of the project activity..
Source of data used:	Project site.
Value applied:	Zero
Justification of the choice of data or description of measurement methods and procedures actually applied :	For Malana-II hydro Electric Project this value is zero, as this is a new power project.
Any comment	-

Data / Parameter:	AP_J
Data unit:	M^2
Description:	Area of the reservoir measured in the surface of the water, after the Implementation of the project activity, when the reservoir is full.
Source of data used:	Project site
Value applied:	Zero
Justification of the choice of data or description of measurement methods and procedures actually applied :	For this project activity, the value is zero as there is a new reservoir.
Any comment:	-

B.6.3 Ex-ante calculation of emission reductions:

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As the project is a run-of-the-river hydro-electric project, which supplies electricity to the respective grid, the methodology chosen is ACM0002/ Version 7, 14th December, 2007. To calculate the Baseline emission factor, the "CO_2 Baseline Database of Indian Power Sector", version 03, 15th December, 2007, which is based on the "Tool to calculate the emission factor for an electricity system" and published by Central electricity Authority (CEA), Government of India has been used. The Emission Reductions have been estimated as follows:

Calculation the operating margin emission factor according to the selected method Average Operating Margin (OM):

Selected Years	2004-05	2005-06	2006-07
Operating Margin (OM) in tonnes CO_2 / MWh	0.97448	0.99365	0.99202
Average of the Three years in t CO_2 / MWh	0.98672		

Calculation of the Build Margin Emission Factor:

Build Margin (BM)	0.62834 tCO_2 / MWh

Calculation of Combined Margin (CM) Emissions Factor - Emission factor for the Grid electricity:

The baseline emission factor (EF_y) is calculated using the Operating Margin emission factor (*EFOM,y*) and the Build Margin emission factor (*EFBM,y*). The baseline emission factor is the weighted average of the Operating Margin emission factor (*EFOM,y*) and the Build Margin emission factor (*EFBM,y*) .

So, $EF_y = W_{OM} \text{ X } EF_{OM,\,y} + W_{BM} \text{ X } EF_{BM,\,y}$

Where
EFy = Combined Margin emission factor
W_{OM} = Weight Operating Margin
$EF_{OM,\,y}$ = Operating Margin Emission Factor = 0.98672 tCO_2 / MWh
W_{BM} = Weight Build Margin
$EF_{BM,\,y}$ = Build Margin Emission Factor = 0.62834 tCO_2 / MWh

Where, the values of W_{OM} and W_{BM}, by default, are 50% (i.e., $W_{OM} = W_{BM} = 0.5$)

So, $EF_y = 0.5 \text{ X } 986.72 + 0.5 \text{ X } 628.34 = 0.80753\ tCO_2$ / MWh

Calculation of Baseline Emission:

The baseline emissions in year y are calculated as:

BEy = EFy x EGy

Where
BEy is the baseline emission for the year y (Combined Margin)
EGy is the electricity generation by the project activity in year y,
EFy is the baseline emission factor determined above.

The amount of electricity generated (EGy), has been sourced from Chapter VI: detailed Power Potential Studies, page number (VI -9) of the Detailed Project Report (DPR), which has been approved by the Central Electricity Authority, Government of India. The value has been taken from the DPR; Salient features; page no. s-(iv); 1.4 as 428 GWh, which is equivalent to 428, 000 MWh. The estimation has been shown as below:

The design energy means the quantum of energy which could be generated in a 90% dependable year with 95% plant availability as per Central Electricity Regulatory Commission (CERC) guideline (Source: Page No. : 172; Power: who's who in India - by Federation of Indian Chambers of Commerce and Industry, website: **http://books.google.com/books?id=2wAi374AAfAC&pg=PA173&lpg=PA17&ots=JFfpQNUidZ&dq=definition,+dependable+year,+hydro#PPA172,M1).**

90% dependable year is a year in which the annual energy generation has the probability of equal to or excess of 90% of the expected period of operation of the scheme.

While planning hydro projects, daily discharge data of the river at the project diversion dam site for about continuous 20 years is taken into consideration.

If discharge data for N years is available, the 90% dependable year defined as (N+1) × 90% in the table arranged in descending-discharge order.

If the discharge data of the river for 20 years have been considered, then the 90% dependable year will be

= (20+1) × 90%
= 21 × .9 = 18.9 ~ 19^{th} year

Therefore, 19^{th} year's discharge data, as arranged in descending order will be considered.

The available daily discharge data of the 19^{th} year are converted into '10 daily discharge data' by averaging the daily discharge data for each 10 days. Therefore, there are 36 readings of such '10 daily discharge data' for the year. This '10 daily discharge data' are used for further calculations of power (MW) and design energy generation (MUs) during each of the 10 daily periods. (Please refer to the Detailed Project Report; Chapter VI; Power Potential studies; Annexure 6.2; page no. VI- 9).

The formula that has been used for power (MW) calculation is as follows:

$$P\ (MW) = \frac{nTG \times 9.81 \times Q \times H}{1000}$$

Where,
P is the power generation in MW
nTG is the combined efficiency of the turbine and generator = 90%
Q is the discharge in cum/ sec.
H is the head in meter available for power generation = Rated head as 608 M

However, the power is restricted to 95% of the installed capacity as per CERC Regulation. If the power from the above formula comes out more than 95% of the installed capacity, the restricted power is considered in energy calculations (Please refer to the excel spreadsheet as provided on Design energy).

The Energy is calculated as follows:

$E = P \times T$

Where,

E = Energy in kWh
T = Time in hours

Therefore, the estimation of the 10 day energy value is:

$E^{10} = P \times 10 \times 24 = P \times 240$ hours

The summation of 36 readings of the 10 daily energy values of 90% dependable year is the design energy for the project (Please refer to the excel spreadsheet as provided on Design energy).

Again, considering the different discharge values as referred above, the annual generation for different installed capacities has been shown below (Reference: Detailed Project Report; Chapter VI; Power Potential studies; Point 6.3.2; page no. VI-3).

Installed Capacity (MW)	90% Dependable year Energy (GWh)	Incremental Energy Generation /MW Increase of Installed Capacity
70	360.30	
75	372.78	2.50
80	385.84	2.61
85	397.67	2.37
90	409.15	2.30
95	419.60	2.09
100	428.00 (Conservative value)	1.60
105	431.60	0.80
110	433.48	0.38
115	434.62	0.23
120	434.75	0.03

From the table, it can be shown that with the increase of the installed capacity, this is a steady increase in energy generation from 70 MW to 100 MW. The increase in energy generation gets substantially low and beyond economical consideration with increase in installed capacity from above 100 MW to 120 MW. This implies that 100 MW is the optimum installed capacity with an optimum generation of 428 GWh, which is equivalent to 428, 000 MWh, for the project activity. As the design discharge data, which is individual characteristics of each river or stream specific to a location, makes it project specific.

So, BEy = 0.80753 tCO_2 / MWh X 428,000 MWh = 345, 622 tonnes CO_2 (tCO_2)

Calculation of the Project Emissions (PEy):

PEy = 0 for this project activity; as the value of the power density is 2857 Watt / m^2, greater than 10 W/m^2.

Leakage calculation (LEy):

As per the methodology ACM 0002, Version 07, Sectoral Scope 1, December 14, 2007 (page no. 10/19; Leakage), no leakage has been applied for the project activity.

Hence, LEy = 0.

Calculation of Emission Reduction:

ERy = BEy – PEy – Ly

Where ERy is the Emission Reduction for the year y
BEy is the baseline emission for the year y (Combined Margin)
PEy is the Project Emissions
Ly is the Leakage

As PEy = Ly = 0;

Therefore, ERy = BEy = EFy x EGy = 345, 622 tonnes of $CO_{2\,e}$ (tCO_2) per year.

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

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The project is expected to reduce 345, 622 tonnes of $CO_{2\,e}$ per year over the crediting period of 2009 to 2019. This value is based on the projected power generation of 428, 000 MWh / year and a Combined Margin emission factor of 0.80753 t CO_2 / MWh.

Table B 2: Summary of the Estimated Emission Reduction

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)
2009	0	345, 622	0	345, 622
2010	0	345, 622	0	345, 622
2011	0	345, 622	0	345, 622
2012	0	345, 622	0	345, 622
2013	0	345, 622	0	345, 622
2014	0	345, 622	0	345, 622
2015	0	345, 622	0	345, 622
2016	0	345, 622	0	345, 622
2017	0	345, 622	0	345, 622
2018	0	345, 622	0	345, 622
Total Emission Reduction in the full Crediting Period	0	3,456,220	0	3,456,220

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

B.7.1 Data and parameters monitored:

(Copy this table for each data and parameter)

Data / Parameter:	EGy
Data unit:	MWh
Description:	Amount of electricity supplied to the Northern Region Grid by the project.
Source of data to be used:	Meters installed at the Inter-connection point.
Value of data applied for the purpose of calculating expected emission reductions in section B.5:	The applied value is 428, 000 MWh. The value has been taken from the DPR; Salient features; page no. s-(iv); 1.4 as 428 GWh, which is equivalent to 428, 000 MWh. During the crediting period, the value will be applicable as measured.
Description of measurement methods and procedures to be applied:	Meter reading of the of the Main Meters/ Check Meters installed at the Interconnection Point shall be taken as at 24:00 hours on each day.. Monthly data of the electricity supplied will also be monitored from the Inter-connection point Meter reading as recorded by the company and the power buyer.
QA/QC procedures:	Each Meter shall be of static type of 0.2% accuracy class confirming to latest IEC-687 and shall meet the requirements of IEGC. One complete spare set of tested, calibrated and sealed Meters shall be kept in safe custody of the Company. All such Meters shall be sealed in the presence of the CTU, PTC and the Company, which seal shall remain intact unless it is broken by the Testing Laboratory for testing and calibration. The Meters (and associated circuits, if necessary) shall be tested and calibrated in accordance with the provisions set out in the Connection Agreement and IEGC. At least once in two (2) tariff years, or at any time when the difference between the readings of the Main meter and the corresponding Check meters is found to exceed zero point four percent (0.4%). Monthly bills for electricity supplied will be used to ensure consistency.
Any comment:	The total data is archived both electronically and on paper and will be kept at least for 2 years after the end of the last crediting period.

Data / Parameter:	Cap_{PJ}
Data unit:	MW
Description:	Installed capacity of the hydro power plant after the implementation of the project activity.
Source of data to be	Project site.

used:	
Value of data applied for the purpose of calculating expected emission reductions in section B.5:	Zero;
Description of measurement methods and procedures to be applied:	The project activity is a new project activity, therefore, the value is zero as applicable as per the methodology. Monitoring of the capacity addition will be done based on the information as available at the project site.
QA/QC procedures: -	No separate QC/QA procedure is required.
Any comment	The total data is archived on paper and will be kept at least for 2 years after the end of the last crediting period.

Data / Parameter:	AP_J
Data unit:	M^2
Description:	Area of the reservoir measured in the surface of the water, after the Implementation of the project activity, when the reservoir is full.
Source of data to be used:	Project site
Value of data applied for the purpose of calculating expected emission reductions in section B.5:	The value applied is zero, as there is a new reservoir.
Description of measurement methods and procedures to be applied:	Various topographical surveys, maps etc.
QA/QC procedures	No separate QC/QA procedure is required.
Any comment:	The total data is archived on paper and will be kept at least for 2 years after the end of the last crediting period.

B.7.2 Description of the monitoring plan:

>>

EPPL will form an operational and management structure in order to monitor emission reductions due to project activity. Under this, a CDM project supporting team will be responsible for the overall cross reviewing of the monitoring plan. Based on the amount of the net electricity supplied, monitoring reports will be prepared by the team and will be reviewed by the Project In charge, who is a qualified engineer with 10-15 years of experience. In case of any irregularity observed, immediate action will be taken.

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)

>>

The information on power plants included in the project boundary is available in the public domain on the websites of Central Electricity Authority (www.cea.nic.in), Ministry of Power (www.powermin.nic.in), Government of India.

Date of completing this baseline study: 27/10/2009
Name of person / entity determining the baseline:

Mallika Bose
Senior Executive
Energy Infratech Private Limited

Contact information of the above entity is furnished below:

Organization:	Energy Infratech Private Limited
Street/P.O. Box,	145-146, Udyog Vihar, Phase – IV
City:	Gurgaon
State/Region:	Haryana – 122015
Country:	India
Telephone:	+91-124-4356700
Fax:	+91-124-4356747
Mobile:	+91-9958150102
Email:	mallika.basu@energyinfratceh.com
Represented By:	
Last Name:	Bose
Middle Name:	
First Name:	Mallika
Designation:	Senior Executive

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:

>>

18/10/2006 (As per the E & M Contract between Everest Power Private Limited (EPPL) and Abir Constructions Private Limited).

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

>>

40 Years

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

The project has chosen a fixed crediting period.

C.2.1. Renewable crediting period

Not Applicable

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

>>

Not Applicable

C.2.1.2. Length of the first crediting period:

>>

Not Applicable

C.2.2. Fixed crediting period:

10 Years

C.2.2.1. Starting date:

>>

01/04/2009 (Commercial Operation Date or date of registration, whichever occurs 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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Under the requirement of the regulatory framework on India, the project has carried out comprehensive Environmental Impacts Study of the project area during its construction and operation phase and develops a suitable Environmental Management Plan (EMP) to mitigate the impacts to its minimum level. The detailed Environmental Impact Assessment (EIA) studies were completed after obtaining the "site clearances" of the project from Ministry of Environment and Forest, Government of India, and submitted to the Himachal Pradesh Paryavaran Protection and Pollution Control Board (HPPPPCB), who after being satisfied, convened a Public Hearing on May 18th & 19th, 2004. **The Public Hearing was successfully completed and as per the recommendation of the Government of Himachal Pradesh, the Ministry of Environment & Forests (MoEF), Government of India, has approved the EIA on 21st June 2005, vide letter no: J -12011/21/2005-IA-I.**

Various other statutory and regulatory clearances are obtained as described below in the context of Environment:

- No Objection Certificate (NOC) from Irrigation & Public Health Department of Government of Himachal Pradesh
- No Objection Certificate (NOC) from Himachal Pradesh Paryavaran Protection and Pollution Control Board (HPPPCB)
- Diversion of Forest Land from Ministry of Environment & Forests, Government of India

The Study Area for the EIA study is briefly described below:

1. Upstream of the Dam Site	7 Km on either side from the periphery of the reservoir submergence
2. Downstream of the Dam Site	7 Km on either side of the river up to the Power House
3. Catchment Area	Rivers draining into the reservoir

The mitigation or enhancement measures in this project as found appropriate to the nature of impacts are stated below:

- Environmental Management during construction phase
- Compensatory afforestation for the loss of forests land and cost of trees and NPV for loss of environmental values
- Maintenance of water quality
- Wildlife conservation
- Air pollution control
- Sustenance and enhancement of fisheries potential

- Greenbelt development
- Roadside Plantation
- Biodiversity conservation
- Public health delivery system
- Catchment area treatment plan
- Muck management plan
- Reservoir Rim Treatment Plan
- Forest protection plan
- Disaster Management Plan

A summary of impacts and proposed measures along with the implementing agencies is given below:

Summary of Impacts, suggested management measures and implementing agency

SL. No.	Parameters	Impact	Management Measures	Implementing Agency
1.	**Land Environment**			
	Construction phase	• Soil erosion due to the extraction of construction material from various quarry sites.	• Proper treatment of quarry site with muck, re-vegetation. etc.	• EPPL
		• Increase in turbidity in the river downstream of dam and power house sites	• Proper collection and disposal of construction spoils.	• EPPL
		• Creation of stagnant water pool in the dry stretch of river.	• Minimum flow of water to avoid the stagnation of water.	• EPPL
		• Generation of muck due to tunnelling operations & roads.	• Disposal at designated sites and provision of suitable check dams.	• EPPL
	Operation phase	• Acquisition of forest and pasture lands.	• Compensatory afforestation has been suggested.	• Forest Department/ EPPL
		• Increased incidence of water- related diseases and other health problems	• Development of dispensary, first- aid, post spraying of insecticides, etc.	• EPPL & District Public Health Department
		• Generation of solid	• Disposal at	

SL. No.	Parameters	Impact	Management Measures	Implementing Agency
		wastes from labour camps/colonies.	Designated landfill site.	• EPPL
2.	**WATER RESOURCES**			
	Operation phase	• River stretch from dam site to tail race outfall will have reduced flow during lean season.	• Minimum flow will be released to maintain the riverside ecology & dilution of domestic effluent.	• EPPL
		• Siltation and sedimentation of reservoir storage.	• Catchment Area Treatment	• Forest Department
3.	**WATER QUALITY**			
	Construction phase	• Water pollution due to disposal of sewage from labour colonies.	• Provision of community toilets • Provision of septic tanks & absorption trenches for treatment of effluents from labour camps. • Minimum flow will be released.	• EPPL
	Operation phase	• Deterioration of water quality in the dry stretch of river due to reduced flow during the lean season.	• Provision of Aerated lagoon	• EPPL
		• Disposal of sewage from project colony.		• EPPL
		• Eutrophication problems.	• Eutrophication risks are minimal, hence, specific management measures are not required.	
4.	**TERRESTRIAL FLORA**			
	Construction phase	• Cutting of trees for meeting fuel wood requirements by labour.	• Provision of community kitchen by the contractors engaged in project	• Project Contractor/ EPPL

SL. No.	Parameters	Impact	Management Measures	Implementing Agency
			construction.	
	Operation phase	• Acquisition of 33.7236 ha of forest and pasture land for various project appurtenances • Acquisition of 17.69 ha of forest land for alignment of transmission line. •	• Compensatory afforestation as per the Indian Forest Conservation Act (1980)	• Forest Department
5.	**TERRESTRIAL FAUNA**			
	Construction phase	• Disturbance to wildlife due to operation of various construction equipments.	• No major wildlife is found, hence, impact is not expected to be significant.	
	Operation phase	• Disturbance to wildlife due to increased accessibility in the area.	• No major wildlife is found, hence impact is not expected to be significant.	
6.	**AQUATIC ECOLOGY**			
	Construction phase	• Marginal decrease in aquatic productivity due to increased turbidity and lesser light penetration.	• Marginal impact, hence no specific management measures are suggested.	
	Operation phase	• Obstruction in the path of migratory fishes.	• Development of hatchery for artificial seed production and stocking of reservoir & river stretch	• Department of Fisheries, Govt. of Himachal Pradesh.
		• Profiling of species adapted to the lacustrine environment.	• Release of minimum flow (0.5 cumecs).	• EPPL
		• Drying of river stretch downstream of dam up to tail race outfall.	• Release of minimum flow.	• EPPL

SL. No.	Parameters	Impact	Management Measures	Implementing Agency
7.	**NOISE ENVIRONMENT**			
	Construction phase	• Increase in noise levels due to operation of various construction equipments.	• Marginal impact, hence no management measures are suggested.	
8.	**AIR ENVIRONMENT**			
	Construction phase	• Increase in air pollution due to use of machinery and other civil activities.	• Cyclones will be provided near the power house site and crushers.	• Project contractor/ EPPL
9.	**SOCIO-ECONOMIC ENVIRONMENT**			
	Construction phase	• Increase in employment potential.		
		• Acquisition of land for alignment of transmission lines submergence and other project appurtenances.	• Compensation as per applicable norms	• EPPL
	Operation phase	• Increased power generation		
		• Greater employment opportunities.		

About 1.1741 ha of private land in village Malana needs to be acquired. About 35-40 families are likely to lose land. Adequate compensation @ Rs. 1 million/ ha is proposed to be paid and also 14% registration fees has been taken into consideration. Thus, total amount of approximately Rs. 1.338 million needs to be earmarked for compensation in lieu of acquisition of private land for various project activities.

The total expenditure on land acquisition works out to about Rs. 4.81 million.

For the affected population, the following rehabilitation measures have been proposed:

- Construction of permanent Hospital building at Malana village;
- Construction of storage tank for drinking water at Malana village;
- Strengthening of the existing pathway between Malana village and the dam site;
- Construction of the community toilets in Malana village;
- Renovation of the existing building of Malana Gram Panchayat;
- Construction of sarai for pilgrims to Malana village;

- Promotion of cable network into the village premises;
- Necessary training facilities shall be provided for development of entrepreneurship to take up self-employment projects as part of R&R benefits. For the purpose of creating self-reliance and economic independence among the PAFs, certain economic activities are suggested. Some training options are Bamboo Furniture Making, Dhaba & Restaurant, Fruit & Vegetable shop, Horticulture, Minor Forest Product, Piggery, Poultry, etc. It is also suggested that the project authority makes a sincere effort in this direction;
- One member from each household would be imparted Vocational Training at the project cost to avail training for development of entrepreneurship to take up self-employment projects at the resettlement zone as part of R&R benefits.

An independent Environmental Management group will be developed at the project site by the project proponent. The task of the group will be to coordinate specific studies to carry out environmental monitoring and to evaluate implementation of environmental mitigatory measures. One Environmental Officer can be posted at the project site, who would report to the project in-charge. The Environment Officer would report to the appropriate authority having adequate power to implement the required measures. The other responsibilities include liaison with relevant departments at the state Government level for effective implementation of the Environmental Management Plan.

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:

>>

The environmental impacts as envisaged through the study of EIA for the project construction and operation stage in the project area, has not been substantial and alarming. The design of the EMP has been taken into consideration of all possible mitigative measures to minimize the impacts.

SECTION E. Stakeholders' comments

>>

Proposed project activity is a large scale hydro power project and has drawn attention of a large section of stakeholders. But as it is a run-of-river project, there are no major resettlement and rehabilitation issues involved. But taking on the social responsibility, the project proponent has completed the social impact survey with the help of the consultant with the stakeholders' participation from the society.

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

>>

The mandatory Public Hearings according to Notification No. SO-318 (E) dated 10-04-1997 issued by the Ministry of Environment & Forests, Govt. of India as a requirement for the Environmental Clearance, also been granted by the Ministry of Environment & Forests, Government of India, were convened by the HP State Environmental Protection & Pollution Control Board near the dam site in Ochin area in village Malana, District Kullu, in the state of Himachal Pradesh (H.P.) on 18^{h} May, 2004. Besides the common people of the project area, the public hearing has been attended by experts and officials from Department of Science & Technology, Government of India, District Collector, Fisheries Department of Himachal Pradesh State Government, Himachal Pradesh State Electricity Board, Himachal Pradesh State Pollution Control Board, Group of Senior Citizen, Gram Panchayat (village administration).

E.2. Summary of the comments received:

>>

The detailed of the comments received and responses have been documented and attached separately.

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

>>

The detailed of the comments received and responses have been documented and attached separately.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Everest Power Private Limited
Street/P.O.Box:	Sushant Lok, Phase – I
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E-Mail:	eppl@sify.com
URL:	
Represented by:	Everest Power Private Limited
Title:	Director
Salutation:	
Last Name:	Jamwal
Middle Name:	Singh
First Name:	Sudhir
Department:	
Mobile:	+91 9810137430
Direct FAX:	+91 124 4356757
Direct tel:	+91 124 4356775
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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

The project is not utilizing any public funding from Annex I Countries. Only term loans from various Indian Financial Institutions and banks have been received for the project activity. All the above funds do not create any diversion of Official Development Assistance (ODA).

Annex 3

BASELINE INFORMATION

According to the methodology ACM0002 version 07, the baseline emissions are the amount of electricity produced times the grid emission factor which is the Combined Margin (CM), calculated as the simple average of the Operating Margin (OM) emission factor and the Build Margin (BM) emission factor. The detailed calculations have been shown in the section B.6.1 and B.6.3 respectively. Adequate data and information is available to estimate the grid emission factor. Central Electricity Authority (CEA) of India has already compiled and published *"CO_2 Baseline Database of Indian Power Sector"* and whose latest version 3.0 has been out for public consumption on 15th December, 2007. This has been used for computing the grid emission factor (Source: http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm).

	Simple Operating Margin (tCO2/MWh) (excl. Imports)							
		2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
	North	0.98	0.98	1.00	0.99	0.97	0.99	0.99
	East	1.22	1.22	1.20	1.23	1.20	1.16	1.13
	South	1.02	1.00	1.01	1.00	1.00	1.01	1.00
	West	0.98	1.01	0.98	0.99	1.01	0.99	0.99
	North-East	0.74	0.71	0.74	0.74	0.71	0.70	0.69
	India	1.02	1.02	1.02	1.03	1.03	1.02	1.01
	Build Margin (tCO2/MWh) (excl. Imports)							
		2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
	North					0.53	0.60	0.63
	East					0.90	0.97	0.93
	South					0.70	0.71	0.71
	West					0.77	0.63	0.59
	North-East					0.15	0.15	0.23
	India					0.69	0.68	0.68
	Combined Margin (tCO2/MWh) (excl. Imports)							
		2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
	North	0.76	0.76	0.77	0.76	0.75	0.80	0.81
	East	1.06	1.06	1.05	1.07	1.05	1.06	1.03
	South	0.86	0.85	0.86	0.85	0.85	0.86	0.85
	West	0.87	0.89	0.88	0.88	0.89	0.81	0.79
	North-East	0.44	0.43	0.44	0.44	0.43	0.42	0.46
	India	0.86	0.86	0.86	0.86	0.86	0.85	0.85

For the calculation of grid emission factor (*EFy*) for Northern Region of India, the values of Operating Margin Emission factor and Build Margin Emission factor have been taken from the publicly available Official database "CO_2 Baseline Database of Indian Power Sector" published by Central Electricity Authority (CEA) Ver. 3, 15th Dec, 2007; http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm). Central Electricity Authority is the regulatory body under Ministry of Power, Government of India. As per the published database and subsequent User Guide, "CO_2 Baseline Database for the Indian Power Sector" Version 3.0, December 2007, page – S-1, para 2 & 3 & page -1, para 2 by CEA (Source: http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm),

"In order to facilitate adoption of authentic baseline emissions data and also to ensure uniformity in the calculations of CO_2 emission reductions by CDM project developers, Central Electricity Authority (CEA), in cooperation with GTZ CDM-India, has compiled a database containing the necessary data on CO_2 emissions for all grid-connected power stations in India".

"The Indian electricity system is divided into five regional grids, viz. Northern, Eastern, Western, Southern, and North-Eastern. Each grid covers several states. As the regional grids are interconnected, there is inter-state and inter-regional exchange. A small power exchange also takes place with neighbouring countries like Bhutan and Nepal. For each of the five regions, the main emission factors are calculated in accordance with the relevant CDM methodologies".

"The purpose of the database is to establish authentic and consistent quantification of the CO_2 emission baseline which can be readily used by CDM project developers in the Indian power sector".

Therefore, as the project activity is located in the Northern region of India, the following table provides data for calculating the Simple Operating Margin emission in a step by step approach for Northern Regional electricity Grid for the most recent 3 years at the time of the PDD submission i.e. 2007.

Generation from Northern Region based Thermal Power Plants (state wise) in 2005-2006

(source: www.cea.nic.in)

1) DELHI :

S_NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2005-06 Net Generation GWh
1	**BADARPUR**	**0**		**720**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**4,866**
1	BADARPUR	1	26-Jul-73	100	CENTER	NTPC	THERMAL	COAL	
1	BADARPUR	2	5-Aug-74	100	CENTER	NTPC	THERMAL	COAL	
1	BADARPUR	3	29-Mar-75	100	CENTER	NTPC	THERMAL	COAL	
1	BADARPUR	4	2-Dec-78	210	CENTER	NTPC	THERMAL	COAL	
1	BADARPUR	5	25-Dec-81	210	CENTER	NTPC	THERMAL	COAL	
2	**I.P.STATION**	**0**		**247.5**	**STATE**	**IPGPCL**	**THERMAL**	**COAL**	**838**
2	I.P.STATION	1	31-Dec-67	62.5	STATE	IPGPCL	THERMAL	COAL	
2	I.P.STATION	2	29-Feb-68	62.5	STATE	IPGPCL	THERMAL	COAL	
2	I.P.STATION	3	31-Mar-68	62.5	STATE	IPGPCL	THERMAL	COAL	
2	I.P.STATION	4	31-Dec-71	60	STATE	IPGPCL	THERMAL	COAL	
3	**RAJGHAT**	**0**		**135**	**STATE**	**IPGPCL**	**THERMAL**	**COAL**	**495**
3	RAJGHAT	1	10-Mar-89	67.5	STATE	IPGPCL	THERMAL	COAL	
3	RAJGHAT	2	24-Nov-89	67.5	STATE	IPGPCL	THERMAL	COAL	
4	**I.P.GT**	**0**		**282**	**STATE**	**IPGPCL**	**THERMAL**	**GAS**	**1,697**
4	I.P.GT	1	28-May-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	2	24-Jun-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	3	31-Jul-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	4	10-Sep-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	5	15-Nov-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	6	14-May-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.WHP 1	7	29-Mar-95	34	STATE	IPGPCL	THERMAL	GAS	
4	I.P.WHP 2	8	31-Oct-95	34	STATE	IPGPCL	THERMAL	GAS	
4	I.P.WHP 3	9	26-Mar-96	34	STATE	IPGPCL	THERMAL	GAS	
5	**PRAGATI CCGT**	**0**		**330.4**	**STATE**	**IPGPCL**	**THERMAL**	**GAS**	**2,227**
5	PRAGATI CCGT	1	15-Mar-02	104.6	STATE	IPGPCL	THERMAL	GAS	716
5	PRAGATI CCGT	2	9-Nov-02	104.6	STATE	IPGPCL	THERMAL	GAS	722
5	PRAGATI CCGT	3	31-Jan-03	121.2	STATE	IPGPCL	THERMAL	GAS	789

2) HARYANA:

S_NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2005-06 Net Generation GWh
6	**F_BAD EXTN.**	**0**		**180**	**STATE**	**HPGCL**	**THERMAL**	**COAL**	**696**
6	F_BAD EXTN.	1	15-Nov-74	60	STATE	HPGCL	THERMAL	COAL	
6	F_BAD EXTN.	2	6-Mar-76	60	STATE	HPGCL	THERMAL	COAL	
6	F_BAD EXTN.	3	1-Apr-81	60	STATE	HPGCL	THERMAL	COAL	
7	**PANIPAT**	**0**		**1360**	**STATE**	**HPGCL**	**THERMAL**	**COAL**	**7,330**
7	PANIPAT	1	30-Mar-79	110	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	2	21-Feb-80	110	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	3	1-Nov-85	110	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	4	11-Jan-87	110	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	5	28-Mar-89	210	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	6	1-Apr-01	210	STATE	HPGCL	THERMAL	COAL	1,536
7	PANIPAT	7	26-Sep-04	250	STATE	HPGCL	THERMAL	COAL	839
7	PANIPAT	8	28-Jan-05	250	STATE	HPGCL	THERMAL	COAL	1,668
8	**F_BAD CCGT**	**0**		**430**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**2,885**
8	F_BAD CCGT	1	29-Jun-99	143	STATE	NTPC	THERMAL	GAS	928
8	F_BAD CCGT	2	18-Oct-99	143	STATE	NTPC	THERMAL	GAS	904
8	F_BAD CCGT	3	31-Jul-00	144	STATE	NTPC	THERMAL	GAS	1,053

3) PUNJAB

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2005-06 Net Generation GWh
9	**GNDTP(BHATINDA)**	**0**		**440**	**STATE**	**PSEB**	**THERMAL**	**COAL**	**2,071**
9	GNDTP(BHATINDA)	1	22-Sep-74	110	STATE	PSEB	THERMAL	COAL	
9	GNDTP(BHATINDA)	2	19-Sep-75	110	STATE	PSEB	THERMAL	COAL	
9	GNDTP(BHATINDA)	3	29-Mar-78	110	STATE	PSEB	THERMAL	COAL	
9	GNDTP(BHATINDA)	4	31-Jan-79	110	STATE	PSEB	THERMAL	COAL	
10	**GHTP (LEH.MOH.)**	**0**		**420**	**STATE**	**PSEB**	**THERMAL**	**COAL**	**2,864**
10	GHTP (LEH.MOH.)	1	29-Dec-97	210	STATE	PSEB	THERMAL	COAL	
10	GHTP (LEH.MOH.)	2	16-Oct-98	210	STATE	PSEB	THERMAL	COAL	1,546
11	**ROPAR**	**0**		**1260**	**STATE**	**PSEB**	**THERMAL**	**COAL**	**8,535**
11	ROPAR	1	26-Sep-84	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	2	29-Mar-85	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	3	31-Mar-88	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	4	29-Jan-89	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	5	29-Mar-92	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	6	30-Mar-93	210	STATE	PSEB	THERMAL	COAL	

4) RAJASTHAN:

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2005-06 Net Generation GWh
12	**KOTA**	**0**		**1045**	**STATE**	**RRVUNL**	**THERMAL**	**COAL**	**7,525**
12	KOTA	1	17-Jan-83	110	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	2	13-Jul-83	110	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	3	25-Sep-88	210	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	4	1-May-89	210	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	5	26-Mar-94	210	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	6	30-Jul-03	195	STATE	RRVUNL	THERMAL	COAL	1,543
15	**SURATGARH**	**0**		**1250**	**STATE**	**RRVUNL**	**THERMAL**	**COAL**	**9,041**
15	SURATGARH	1	10-May-98	250	STATE	RRVUNL	THERMAL	COAL	
15	SURATGARH	2	28-Mar-00	250	STATE	RRVUNL	THERMAL	COAL	1,920
15	SURATGARH	3	29-Oct-01	250	STATE	RRVUNL	THERMAL	COAL	1,732
15	SURATGARH	4	25-Mar-02	250	STATE	RRVUNL	THERMAL	COAL	1,761
15	SURATGARH	5	30-Jun-03	250	STATE	RRVUNL	THERMAL	COAL	1,847
16	**RAMGARH GT**	**0**		**113.8**	**STATE**	**RRVUNL**	**THERMAL**	**GAS**	**404**
16	RAMGARH GT	1	15-Nov-94	3	STATE	RRVUNL	THERMAL	GAS	
16	RAMGARH GT	2	12-Jan-96	35.5	STATE	RRVUNL	THERMAL	GAS	
16	RAMGARH GT	3	7-Aug-02	37.5	STATE	RRVUNL	THERMAL	GAS	0
16	RAMGARH ST 1	4	31-Mar-03	37.8	STATE	RRVUNL	THERMAL	GAS	0
17	**ANTA GT**	**0**		**413**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**2,739**
17	ANTA GT	1	20-Jan-89	88	CENTER	NTPC	THERMAL	GAS	
17	ANTA GT	2	4-Mar-89	88	CENTER	NTPC	THERMAL	GAS	
17	ANTA GT	3	4-May-89	88	CENTER	NTPC	THERMAL	GAS	
17	ANTA GT	4	5-Mar-90	149	CENTER	NTPC	THERMAL	GAS	

5) UTTAR PRADESH

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2005-06 Net Generation GWh
18	**OBRA-A**	**0**		**1550**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**4,733**
18	OBRA	1	1-Jul-92	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	2	11-Mar-68	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	3	13-Oct-68	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	4	16-Jul-69	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	5	30-Jul-71	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	6	31-Oct-73	100	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	7	14-Dec-74	100	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	8	15-Sep-75	100	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	9	26-Jan-80	200	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	10	14-Jan-79	200	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	11	31-Dec-77	200	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	12	28-Mar-81	200	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	13	21-Jul-82	200	STATE	UPRVUNL	THERMAL	COAL	
19	**PANKI**	**0**		**252**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**864**
19	PANKI	1	19-Feb-85	32	STATE	UPRVUNL	THERMAL	COAL	
19	PANKI	2	10-Nov-76	110	STATE	UPRVUNL	THERMAL	COAL	
19	PANKI	3	24-Mar-77	110	STATE	UPRVUNL	THERMAL	COAL	
20	**H_GANJ B**	**0**		**450**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**432**
20	H_GANJ B	1	29-Feb-68	50	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	2	1-Jul-92	50	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	3	22-Jan-72	60	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	4	18-Sep-72	60	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	5	21-Mar-77	60	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	6	26-Aug-81	60	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	7	31-Mar-78	110	STATE	UPRVUNL	THERMAL	COAL	

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2005-06 Net Generation GWh
21	**PARICHA**	**0**		**430**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**679**
21	PARICHA	1	31-Mar-84	110	STATE	UPRVUNL	THERMAL	COAL	
21	PARICHA	2	25-Feb-85	110	STATE	UPRVUNL	THERMAL	COAL	
21	PARICHA	3	29-Mar-06	210	STATE	UPRVUNL	THERMAL	COAL	4
22	**ANPARA**	**0**		**1630**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**10,547**
22	ANPARA	1	24-Mar-86	210	STATE	UPRVUNL	THERMAL	COAL	
22	ANPARA	2	28-Feb-87	210	STATE	UPRVUNL	THERMAL	COAL	
22	ANPARA	3	12-Mar-88	210	STATE	UPRVUNL	THERMAL	COAL	
22	ANPARA	4	19-Jul-93	500	STATE	UPRVUNL	THERMAL	COAL	
22	ANPARA	5	4-Jul-94	500	STATE	UPRVUNL	THERMAL	COAL	
23	**SINGRAULI STPS**	**0**		**2000**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**14,401**
23	SINGRAULI STPS	1	13-Feb-82	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	2	25-Nov-82	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	3	28-Mar-83	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	4	2-Nov-83	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	5	26-Feb-84	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	6	23-Dec-86	500	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	7	24-Nov-87	500	CENTER	NTPC	THERMAL	COAL	
24	**RIHAND**	**0**		**2000**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**9,866**
24	RIHAND	1	31-Mar-88	500	CENTER	NTPC	THERMAL	COAL	
24	RIHAND	2	5-Jul-89	500	CENTER	NTPC	THERMAL	COAL	
24	RIHAND	3	31-Jan-05	500	CENTER	NTPC	THERMAL	COAL	2,807
24	RIHAND	4	24-Sep-05	500	CENTER	NTPC	THERMAL	COAL	1,446
25	**UNCHAHAR**	**0**		**840**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**6,451**
25	UNCHAHAR	1	21-Nov-88	210	CENTER	NTPC	THERMAL	COAL	
25	UNCHAHAR	2	22-Mar-89	210	CENTER	NTPC	THERMAL	COAL	
25	UNCHAHAR	3	27-Jan-99	210	CENTER	NTPC	THERMAL	COAL	1,587
25	UNCHAHAR	4	22-Oct-99	210	CENTER	NTPC	THERMAL	COAL	1,619
26	**DADRI (NCTPP)**	**0**		**840**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**6,268**
26	DADRI (NCTPP)	1	21-Dec-91	210	CENTER	NTPC	THERMAL	COAL	
26	DADRI (NCTPP)	2	18-Dec-92	210	CENTER	NTPC	THERMAL	COAL	
26	DADRI (NCTPP)	3	16-Jun-92	210	CENTER	NTPC	THERMAL	COAL	
26	DADRI (NCTPP)	4	24-Mar-94	210	CENTER	NTPC	THERMAL	COAL	
27	**TANDA**	**0**		**440**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**2,935**
27	TANDA	1	23-Jan-88	110	CENTER	NTPC	THERMAL	COAL	
27	TANDA	2	11-Mar-89	110	CENTER	NTPC	THERMAL	COAL	
27	TANDA	3	28-Mar-90	110	CENTER	NTPC	THERMAL	COAL	
27	TANDA	4	20-Feb-98	110	CENTER	NTPC	THERMAL	COAL	
28	**AURAIYA GT**	**0**		**652**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**4,204**
28	AURAIYA GT	1	29-Mar-89	112	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	2	21-Jul-89	112	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	3	9-Aug-89	112	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	4	29-Sep-89	112	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	5	29-Dec-89	102	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	6	12-Jun-90	102	CENTER	NTPC	THERMAL	GAS	
29	**DADRI GT**	**0**		**817**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**5,269**
29	DADRI GT	1	21-Feb-92	131	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	2	26-Mar-92	131	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	3	6-Jun-92	131	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	4	14-Oct-92	131	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	5	26-Feb-94	146.5	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	6	27-Mar-93	146.5	CENTER	NTPC	THERMAL	GAS	

6) JAMMU & KASHMIR :

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2005-06 Net Generation GWh
30	**PAMPORE GT**	**0**		**175**	**STATE**	**JKEB**	**THERMAL**	**DISL**	**9**
30	PAMPORE GT	1	31-Mar-89	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	2	20-Jul-89	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	3	11-Dec-89	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	4	7-Jan-94	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	5	7-Feb-94	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	6	4-Apr-94	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	7	30-Mar-95	25	STATE	JKEB	THERMAL	DISL	

Generation from Northern Region based Thermal Power Plants in 2004-05

1) DELHI :

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2004-05 Gross Generation GWh
1	**BADARPUR**	**0**		**720**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**5,463**
1	BADARPUR	1	26-Jul-73	100	CENTER	NTPC	THERMAL	COAL	685
1	BADARPUR	2	5-Aug-74	100	CENTER	NTPC	THERMAL	COAL	737
1	BADARPUR	3	29-Mar-75	100	CENTER	NTPC	THERMAL	COAL	688
1	BADARPUR	4	2-Dec-78	210	CENTER	NTPC	THERMAL	COAL	1,672
1	BADARPUR	5	25-Dec-81	210	CENTER	NTPC	THERMAL	COAL	1,682
2	**I.P.STATION**	**0**		**247.5**	**STATE**	**IPGPCL**	**THERMAL**	**COAL**	**920**
2	I.P.STATION	1	31-Dec-67	62.5	STATE	IPGPCL	THERMAL	COAL	237
2	I.P.STATION	2	29-Feb-68	62.5	STATE	IPGPCL	THERMAL	COAL	150
2	I.P.STATION	3	31-Mar-68	62.5	STATE	IPGPCL	THERMAL	COAL	284
2	I.P.STATION	4	31-Dec-71	60	STATE	IPGPCL	THERMAL	COAL	249
3	**RAJGHAT**	**0**		**135**	**STATE**	**IPGPCL**	**THERMAL**	**COAL**	**697**
3	RAJGHAT	1	10-Mar-89	67.5	STATE	IPGPCL	THERMAL	COAL	343
3	RAJGHAT	2	24-Nov-89	67.5	STATE	IPGPCL	THERMAL	COAL	354
4	**I.P.GT**	**0**		**282**	**STATE**	**IPGPCL**	**THERMAL**	**GAS**	**1,540**
4	I.P.GT	1	28-May-86	30	STATE	IPGPCL	THERMAL	GAS	230
4	I.P.GT	2	24-Jun-86	30	STATE	IPGPCL	THERMAL	GAS	58
4	I.P.GT	3	31-Jul-86	30	STATE	IPGPCL	THERMAL	GAS	209
4	I.P.GT	4	10-Sep-86	30	STATE	IPGPCL	THERMAL	GAS	236
4	I.P.GT	5	15-Nov-86	30	STATE	IPGPCL	THERMAL	GAS	213
4	I.P.GT	6	14-May-86	30	STATE	IPGPCL	THERMAL	GAS	216
4	I.P.WHP 1	7	29-Mar-95	34	STATE	IPGPCL	THERMAL	GAS	87
4	I.P.WHP 2	8	31-Oct-95	34	STATE	IPGPCL	THERMAL	GAS	152
4	I.P.WHP 3	9	26-Mar-96	34	STATE	IPGPCL	THERMAL	GAS	140
5	**PRAGATI CCGT**	**0**		**330.4**	**STATE**	**IPGPCL**	**THERMAL**	**GAS**	**2,552**
5	PRAGATI CCGT	1	15-Mar-02	104.6	STATE	IPGPCL	THERMAL	GAS	841
5	PRAGATI CCGT	2	9-Nov-02	104.6	STATE	IPGPCL	THERMAL	GAS	796
5	PRAGATI CCGT	3	31-Jan-03	121.2	STATE	IPGPCL	THERMAL	GAS	914

2) HARYANA:

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2004-05 Gross Generation GWh
6	**F_BAD EXTN.**	**0**		**180**	**STATE**	**HPGCL**	**THERMAL**	**COAL**	**868**
6	F_BAD EXTN.	1	15-Nov-74	60	STATE	HPGCL	THERMAL	COAL	286
6	F_BAD EXTN.	2	6-Mar-76	60	STATE	HPGCL	THERMAL	COAL	233
6	F_BAD EXTN.	3	1-Apr-81	60	STATE	HPGCL	THERMAL	COAL	350
7	**PANIPAT**	**0**		**1360**	**STATE**	**HPGCL**	**THERMAL**	**COAL**	**5,757**
7	PANIPAT	1	30-Mar-79	110	STATE	HPGCL	THERMAL	COAL	507
7	PANIPAT	2	21-Feb-80	110	STATE	HPGCL	THERMAL	COAL	572
7	PANIPAT	3	1-Nov-85	110	STATE	HPGCL	THERMAL	COAL	674
7	PANIPAT	4	11-Jan-87	110	STATE	HPGCL	THERMAL	COAL	625
7	PANIPAT	5	28-Mar-89	210	STATE	HPGCL	THERMAL	COAL	1,467
7	PANIPAT	6	1-Apr-01	210	STATE	HPGCL	THERMAL	COAL	1,481
7	PANIPAT	7	26-Sep-04	250	STATE	HPGCL	THERMAL	COAL	431
7	PANIPAT	8	28-Jan-05	250	STATE	HPGCL	THERMAL	COAL	0
8	**F_BAD CCGT**	**0**		**430**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**3,162**
8	F_BAD CCGT	1	29-Jun-99	143	STATE	NTPC	THERMAL	GAS	1,001
8	F_BAD CCGT	2	18-Oct-99	143	STATE	NTPC	THERMAL	GAS	1,028
8	F_BAD CCGT	3	31-Jul-00	144	STATE	NTPC	THERMAL	GAS	1,133

3) PUNJAB

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2004-05 Gross Generation GWh
9	**GNDTP(BHATINDA)**	**0**		**440**	**STATE**	**PSEB**	**THERMAL**	**COAL**	**1,992**
9	GNDTP(BHATINDA)	1	22-Sep-74	110	STATE	PSEB	THERMAL	COAL	631
9	GNDTP(BHATINDA)	2	19-Sep-75	110	STATE	PSEB	THERMAL	COAL	0
9	GNDTP(BHATINDA)	3	29-Mar-78	110	STATE	PSEB	THERMAL	COAL	696
9	GNDTP(BHATINDA)	4	31-Jan-79	110	STATE	PSEB	THERMAL	COAL	667
10	**GHTP (LEH.MOH.)**	**0**		**420**	**STATE**	**PSEB**	**THERMAL**	**COAL**	**3,309**
10	GHTP (LEH.MOH.)	1	29-Dec-97	210	STATE	PSEB	THERMAL	COAL	1,773
10	GHTP (LEH.MOH.)	2	16-Oct-98	210	STATE	PSEB	THERMAL	COAL	1,535
11	**ROPAR**	**0**		**1260**	**STATE**	**PSEB**	**THERMAL**	**COAL**	**9,083**
11	ROPAR	1	26-Sep-84	210	STATE	PSEB	THERMAL	COAL	1,600
11	ROPAR	2	29-Mar-85	210	STATE	PSEB	THERMAL	COAL	1,391
11	ROPAR	3	31-Mar-88	210	STATE	PSEB	THERMAL	COAL	1,502
11	ROPAR	4	29-Jan-89	210	STATE	PSEB	THERMAL	COAL	1,608
11	ROPAR	5	29-Mar-92	210	STATE	PSEB	THERMAL	COAL	1,437
11	ROPAR	6	30-Mar-93	210	STATE	PSEB	THERMAL	COAL	1,545

4) RAJASTHAN:

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2004-05 Gross Generation GWh
12	**KOTA**	**0**		**1045**	**STATE**	**RRVUNL**	**THERMAL**	**COAL**	**7,431**
12	KOTA	1	17-Jan-83	110	STATE	RRVUNL	THERMAL	COAL	783
12	KOTA	2	13-Jul-83	110	STATE	RRVUNL	THERMAL	COAL	847
12	KOTA	3	25-Sep-88	210	STATE	RRVUNL	THERMAL	COAL	1,672
12	KOTA	4	1-May-89	210	STATE	RRVUNL	THERMAL	COAL	1,663
12	KOTA	5	26-Mar-94	210	STATE	RRVUNL	THERMAL	COAL	1,316
12	KOTA	6	30-Jul-03	195	STATE	RRVUNL	THERMAL	COAL	1,470
15	**SURATGARH**	**0**		**1250**	**STATE**	**RRVUNL**	**THERMAL**	**COAL**	**9,362**
15	SURATGARH	1	10-May-98	250	STATE	RRVUNL	THERMAL	COAL	1,876
15	SURATGARH	2	28-Mar-00	250	STATE	RRVUNL	THERMAL	COAL	1,705
15	SURATGARH	3	29-Oct-01	250	STATE	RRVUNL	THERMAL	COAL	1,876
15	SURATGARH	4	25-Mar-02	250	STATE	RRVUNL	THERMAL	COAL	1,951
15	SURATGARH	5	30-Jun-03	250	STATE	RRVUNL	THERMAL	COAL	1,955
16	**RAMGARH GT**	**0**		**113.8**	**STATE**	**RRVUNL**	**THERMAL**	**GAS**	**360**
16	RAMGARH GT	1	15-Nov-94	3	STATE	RRVUNL	THERMAL	GAS	341
16	RAMGARH GT	2	12-Jan-96	35.5	STATE	RRVUNL	THERMAL	GAS	1
16	RAMGARH GT	3	7-Aug-02	37.5	STATE	RRVUNL	THERMAL	GAS	1
16	RAMGARH ST 1	4	31-Mar-03	37.8	STATE	RRVUNL	THERMAL	GAS	17
17	**ANTA GT**	**0**		**413**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**2,785**
17	ANTA GT	1	20-Jan-89	88	CENTER	NTPC	THERMAL	GAS	588
17	ANTA GT	2	4-Mar-89	88	CENTER	NTPC	THERMAL	GAS	568
17	ANTA GT	3	4-May-89	88	CENTER	NTPC	THERMAL	GAS	597
17	ANTA GT	4	5-Mar-90	149	CENTER	NTPC	THERMAL	GAS	1,033

5) UTTAR PRADESH

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2004-05 Gross Generation GWh
18	**OBRA-A**	**0**		**1550**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**5,553**
18	OBRA	1	1-Jul-92	50	STATE	UPRVUNL	THERMAL	COAL	0
18	OBRA	2	11-Mar-68	50	STATE	UPRVUNL	THERMAL	COAL	0
18	OBRA	3	13-Oct-68	50	STATE	UPRVUNL	THERMAL	COAL	0
18	OBRA	4	16-Jul-69	50	STATE	UPRVUNL	THERMAL	COAL	171
18	OBRA	5	30-Jul-71	50	STATE	UPRVUNL	THERMAL	COAL	108
18	OBRA	6	31-Oct-73	100	STATE	UPRVUNL	THERMAL	COAL	142
18	OBRA	7	14-Dec-74	100	STATE	UPRVUNL	THERMAL	COAL	0
18	OBRA	8	15-Sep-75	100	STATE	UPRVUNL	THERMAL	COAL	123
18	OBRA	9	26-Jan-80	200	STATE	UPRVUNL	THERMAL	COAL	1,039
18	OBRA	10	14-Jan-79	200	STATE	UPRVUNL	THERMAL	COAL	1,009
18	OBRA	11	31-Dec-77	200	STATE	UPRVUNL	THERMAL	COAL	737
18	OBRA	12	28-Mar-81	200	STATE	UPRVUNL	THERMAL	COAL	1,169
18	OBRA	13	21-Jul-82	200	STATE	UPRVUNL	THERMAL	COAL	1,054
19	**PANKI**	**0**		**252**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**1,043**
19	PANKI	1	19-Feb-85	32	STATE	UPRVUNL	THERMAL	COAL	0
19	PANKI	2	10-Nov-76	110	STATE	UPRVUNL	THERMAL	COAL	578
19	PANKI	3	24-Mar-77	110	STATE	UPRVUNL	THERMAL	COAL	466

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2004-05 Gross Generation GWh
20	**H_GANJ B**	**0**		**450**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**631**
20	H_GANJ B	1	29-Feb-68	50	STATE	UPRVUNL	THERMAL	COAL	0
20	H_GANJ B	2	1-Jul-92	50	STATE	UPRVUNL	THERMAL	COAL	0
20	H_GANJ B	3	22-Jan-72	60	STATE	UPRVUNL	THERMAL	COAL	104
20	H_GANJ B	4	18-Sep-72	60	STATE	UPRVUNL	THERMAL	COAL	174
20	H_GANJ B	5	21-Mar-77	60	STATE	UPRVUNL	THERMAL	COAL	0
20	H_GANJ B	6	26-Aug-81	60	STATE	UPRVUNL	THERMAL	COAL	0
20	H_GANJ B	7	31-Mar-78	110	STATE	UPRVUNL	THERMAL	COAL	354
21	**PARICHA**	**0**		**430**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**967**
21	PARICHA	1	31-Mar-84	110	STATE	UPRVUNL	THERMAL	COAL	390
21	PARICHA	2	25-Feb-85	110	STATE	UPRVUNL	THERMAL	COAL	576
21	PARICHA	3	29-Mar-06	210	STATE	UPRVUNL	THERMAL	COAL	0
22	**ANPARA**	**0**		**1630**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**11,509**
22	ANPARA	1	24-Mar-86	210	STATE	UPRVUNL	THERMAL	COAL	1,407
22	ANPARA	2	28-Feb-87	210	STATE	UPRVUNL	THERMAL	COAL	1,284
22	ANPARA	3	12-Mar-88	210	STATE	UPRVUNL	THERMAL	COAL	1,474
22	ANPARA	4	19-Jul-93	500	STATE	UPRVUNL	THERMAL	COAL	3,828
22	ANPARA	5	4-Jul-94	500	STATE	UPRVUNL	THERMAL	COAL	3,518
23	**SINGRAULI STPS**	**0**		**2000**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**15,803**
23	SINGRAULI STPS	1	13-Feb-82	200	CENTER	NTPC	THERMAL	COAL	1,671
23	SINGRAULI STPS	2	25-Nov-82	200	CENTER	NTPC	THERMAL	COAL	1,510
23	SINGRAULI STPS	3	28-Mar-83	200	CENTER	NTPC	THERMAL	COAL	1,569
23	SINGRAULI STPS	4	2-Nov-83	200	CENTER	NTPC	THERMAL	COAL	1,659
23	SINGRAULI STPS	5	26-Feb-84	200	CENTER	NTPC	THERMAL	COAL	1,615
23	SINGRAULI STPS	6	23-Dec-86	500	CENTER	NTPC	THERMAL	COAL	3,746
23	SINGRAULI STPS	7	24-Nov-87	500	CENTER	NTPC	THERMAL	COAL	4,036
24	**RIHAND**	**0**		**2000**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**7,988**
24	RIHAND	1	31-Mar-88	500	CENTER	NTPC	THERMAL	COAL	4,066
24	RIHAND	2	5-Jul-89	500	CENTER	NTPC	THERMAL	COAL	3,921
24	RIHAND	3	31-Jan-05	500	CENTER	NTPC	THERMAL	COAL	0
24	RIHAND	4	24-Sep-05	500	CENTER	NTPC	THERMAL	COAL	0
25	**UNCHAHAR**	**0**		**840**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**6,781**
25	UNCHAHAR	1	21-Nov-88	210	CENTER	NTPC	THERMAL	COAL	1,625
25	UNCHAHAR	2	22-Mar-89	210	CENTER	NTPC	THERMAL	COAL	1,718
25	UNCHAHAR	3	27-Jan-99	210	CENTER	NTPC	THERMAL	COAL	1,691
25	UNCHAHAR	4	22-Oct-99	210	CENTER	NTPC	THERMAL	COAL	1,747
26	**DADRI (NCTPP)**	**0**		**840**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**6,831**
26	DADRI (NCTPP)	1	21-Dec-91	210	CENTER	NTPC	THERMAL	COAL	1,748
26	DADRI (NCTPP)	2	18-Dec-92	210	CENTER	NTPC	THERMAL	COAL	1,669
26	DADRI (NCTPP)	3	16-Jun-92	210	CENTER	NTPC	THERMAL	COAL	1,713
26	DADRI (NCTPP)	4	24-Mar-94	210	CENTER	NTPC	THERMAL	COAL	1,700
27	**TANDA**	**0**		**440**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**3,317**
27	TANDA	1	23-Jan-88	110	CENTER	NTPC	THERMAL	COAL	809
27	TANDA	2	11-Mar-89	110	CENTER	NTPC	THERMAL	COAL	841
27	TANDA	3	28-Mar-90	110	CENTER	NTPC	THERMAL	COAL	836
27	TANDA	4	20-Feb-98	110	CENTER	NTPC	THERMAL	COAL	831
28	**AURAIYA GT**	**0**		**652**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**4,118**
28	AURAIYA GT	1	29-Mar-89	112	CENTER	NTPC	THERMAL	GAS	801
28	AURAIYA GT	2	21-Jul-89	112	CENTER	NTPC	THERMAL	GAS	798
28	AURAIYA GT	3	9-Aug-89	112	CENTER	NTPC	THERMAL	GAS	782
28	AURAIYA GT	4	29-Sep-89	112	CENTER	NTPC	THERMAL	GAS	432
28	AURAIYA GT	5	29-Dec-89	102	CENTER	NTPC	THERMAL	GAS	754
28	AURAIYA GT	6	12-Jun-90	102	CENTER	NTPC	THERMAL	GAS	553
29	**DADRI GT**	**0**		**817**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**5,457**
29	DADRI GT	1	21-Feb-92	131	CENTER	NTPC	THERMAL	GAS	962
29	DADRI GT	2	26-Mar-92	131	CENTER	NTPC	THERMAL	GAS	791
29	DADRI GT	3	6-Jun-92	131	CENTER	NTPC	THERMAL	GAS	890
29	DADRI GT	4	14-Oct-92	131	CENTER	NTPC	THERMAL	GAS	823
29	DADRI GT	5	26-Feb-94	146.5	CENTER	NTPC	THERMAL	GAS	1,030
29	DADRI GT	6	27-Mar-93	146.5	CENTER	NTPC	THERMAL	GAS	963

6) JAMMU & KASHMIR :

SI NO	NAME	UNIT NO	DT COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2004-05 Gross Generation GWh
30	**PAMPORE GT**	**0**		**175**	**STATE**	**JKEB**	**THERMAL**	**DISL**	**24**
30	PAMPORE GT	1	31-Mar-89	25	STATE	JKEB	THERMAL	DISL	21
30	PAMPORE GT	2	20-Jul-89	25	STATE	JKEB	THERMAL	DISL	3
30	PAMPORE GT	3	11-Dec-89	25	STATE	JKEB	THERMAL	DISL	0
30	PAMPORE GT	4	7-Jan-94	25	STATE	JKEB	THERMAL	DISL	0
30	PAMPORE GT	5	7-Feb-94	25	STATE	JKEB	THERMAL	DISL	0
30	PAMPORE GT	6	4-Apr-94	25	STATE	JKEB	THERMAL	DISL	0
30	PAMPORE GT	7	30-Mar-95	25	STATE	JKEB	THERMAL	DISL	0

Generation from Northern Region based Thermal Power Plants in 2003-04

1) DELHI :

S_NO	NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2003-04 Net Generation GWh
1	**BADARPUR**	**0**		**720**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**4,943**
1	BADARPUR	1	26-Jul-73	100	CENTER	NTPC	THERMAL	COAL	
1	BADARPUR	2	5-Aug-74	100	CENTER	NTPC	THERMAL	COAL	
1	BADARPUR	3	29-Mar-75	100	CENTER	NTPC	THERMAL	COAL	
1	BADARPUR	4	2-Dec-78	210	CENTER	NTPC	THERMAL	COAL	
1	BADARPUR	5	25-Dec-81	210	CENTER	NTPC	THERMAL	COAL	
2	**I.P.STATION**	**0**		**247.5**	**STATE**	**IPGPCL**	**THERMAL**	**COAL**	**669**
2	I.P.STATION	1	31-Dec-67	62.5	STATE	IPGPCL	THERMAL	COAL	
2	I.P.STATION	2	29-Feb-68	62.5	STATE	IPGPCL	THERMAL	COAL	
2	I.P.STATION	3	31-Mar-68	62.5	STATE	IPGPCL	THERMAL	COAL	
2	I.P.STATION	4	31-Dec-71	60	STATE	IPGPCL	THERMAL	COAL	
3	**RAJGHAT**	**0**		**135**	**STATE**	**IPGPCL**	**THERMAL**	**COAL**	**683**
3	RAJGHAT	1	10-Mar-89	67.5	STATE	IPGPCL	THERMAL	COAL	
3	RAJGHAT	2	24-Nov-89	67.5	STATE	IPGPCL	THERMAL	COAL	
4	**I.P.GT**	**0**		**282**	**STATE**	**IPGPCL**	**THERMAL**	**GAS**	**1,189**
4	I.P.GT	1	28-May-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	2	24-Jun-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	3	31-Jul-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	4	10-Sep-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	5	15-Nov-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.GT	6	14-May-86	30	STATE	IPGPCL	THERMAL	GAS	
4	I.P.WHP 1	7	29-Mar-95	34	STATE	IPGPCL	THERMAL	GAS	
4	I.P.WHP 2	8	31-Oct-95	34	STATE	IPGPCL	THERMAL	GAS	
4	I.P.WHP 3	9	26-Mar-96	34	STATE	IPGPCL	THERMAL	GAS	

2) HARYANA:

S_NO	NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2003-04 Net Generation GWh
5	**PRAGATI CCGT**	**0**		**330.4**	**STATE**	**IPGPCL**	**THERMAL**	**GAS**	**2,345**
5	PRAGATI CCGT	1	15-Mar-02	104.6	STATE	IPGPCL	THERMAL	GAS	
5	PRAGATI CCGT	2	9-Nov-02	104.6	STATE	IPGPCL	THERMAL	GAS	
5	PRAGATI CCGT	3	31-Jan-03	121.2	STATE	IPGPCL	THERMAL	GAS	
6	**F_BAD EXTN.**	**0**		**180**	**STATE**	**HPGCL**	**THERMAL**	**COAL**	**689**
6	F_BAD EXTN.	1	15-Nov-74	60	STATE	HPGCL	THERMAL	COAL	
6	F_BAD EXTN.	2	6-Mar-76	60	STATE	HPGCL	THERMAL	COAL	
6	F_BAD EXTN.	3	1-Apr-81	60	STATE	HPGCL	THERMAL	COAL	
7	**PANIPAT**	**0**		**1360**	**STATE**	**HPGCL**	**THERMAL**	**COAL**	**5,350**
7	PANIPAT	1	30-Mar-79	110	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	2	21-Feb-80	110	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	3	1-Nov-85	110	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	4	11-Jan-87	110	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	5	28-Mar-89	210	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	6	1-Apr-01	210	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	7	26-Sep-04	250	STATE	HPGCL	THERMAL	COAL	
7	PANIPAT	8	28-Jan-05	250	STATE	HPGCL	THERMAL	COAL	
8	**F_BAD CCGT**	**0**		**430**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**2,727**
8	F_BAD CCGT	1	29-Jun-99	143	STATE	NTPC	THERMAL	GAS	
8	F_BAD CCGT	2	18-Oct-99	143	STATE	NTPC	THERMAL	GAS	
8	F_BAD CCGT	3	31-Jul-00	144	STATE	NTPC	THERMAL	GAS	

3) PUNJAB :

S_NO	NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2003-04 Net Generation GWh
9	**GNDTP(BHATINDA)**	**0**		**440**	**STATE**	**PSEB**	**THERMAL**	**COAL**	**2,308**
9	GNDTP(BHATINDA)	1	22-Sep-74	110	STATE	PSEB	THERMAL	COAL	
9	GNDTP(BHATINDA)	2	19-Sep-75	110	STATE	PSEB	THERMAL	COAL	
9	GNDTP(BHATINDA)	3	29-Mar-78	110	STATE	PSEB	THERMAL	COAL	
9	GNDTP(BHATINDA)	4	31-Jan-79	110	STATE	PSEB	THERMAL	COAL	
10	**GHTP (LEH.MOH.)**	**0**		**420**	**STATE**	**PSEB**	**THERMAL**	**COAL**	**3,079**
10	GHTP (LEH.MOH.)	1	29-Dec-97	210	STATE	PSEB	THERMAL	COAL	
10	GHTP (LEH.MOH.)	2	16-Oct-98	210	STATE	PSEB	THERMAL	COAL	
11	**ROPAR**	**0**		**1260**	**STATE**	**PSEB**	**THERMAL**	**COAL**	**7,612**
11	ROPAR	1	26-Sep-84	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	2	29-Mar-85	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	3	31-Mar-88	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	4	29-Jan-89	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	5	29-Mar-92	210	STATE	PSEB	THERMAL	COAL	
11	ROPAR	6	30-Mar-93	210	STATE	PSEB	THERMAL	COAL	

4) RAJASTHAN:

S_NO	NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2003-04 Net Generation GWh
12	**KOTA**	**0**		**1045**	**STATE**	**RRVUNL**	**THERMAL**	**COAL**	**5,792**
12	KOTA	1	17-Jan-83	110	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	2	13-Jul-83	110	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	3	25-Sep-88	210	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	4	1-May-89	210	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	5	26-Mar-94	210	STATE	RRVUNL	THERMAL	COAL	
12	KOTA	6	30-Jul-03	195	STATE	RRVUNL	THERMAL	COAL	
15	**SURATGARH**	**0**		**1250**	**STATE**	**RRVUNL**	**THERMAL**	**COAL**	**7,419**
15	SURATGARH	1	10-May-98	250	STATE	RRVUNL	THERMAL	COAL	
15	SURATGARH	2	28-Mar-00	250	STATE	RRVUNL	THERMAL	COAL	
15	SURATGARH	3	29-Oct-01	250	STATE	RRVUNL	THERMAL	COAL	
15	SURATGARH	4	25-Mar-02	250	STATE	RRVUNL	THERMAL	COAL	
15	SURATGARH	5	30-Jun-03	250	STATE	RRVUNL	THERMAL	COAL	
16	**RAMGARH GT**	**0**		**113.8**	**STATE**	**RRVUNL**	**THERMAL**	**GAS**	**206**
16	RAMGARH GT	1	15-Nov-94	3	STATE	RRVUNL	THERMAL	GAS	
16	RAMGARH GT	2	12-Jan-96	35.5	STATE	RRVUNL	THERMAL	GAS	
16	RAMGARH GT	3	7-Aug-02	37.5	STATE	RRVUNL	THERMAL	GAS	
16	RAMGARH ST 1	4	31-Mar-03	37.8	STATE	RRVUNL	THERMAL	GAS	
17	**ANTA GT**	**0**		**413**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**2,702**
17	ANTA GT	1	20-Jan-89	88	CENTER	NTPC	THERMAL	GAS	
17	ANTA GT	2	4-Mar-89	88	CENTER	NTPC	THERMAL	GAS	
17	ANTA GT	3	4-May-89	88	CENTER	NTPC	THERMAL	GAS	
17	ANTA GT	4	5-Mar-90	149	CENTER	NTPC	THERMAL	GAS	

5) UTTAR PRADESH:

S_NO	NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2003-04 Net Generation GWh
18	**OBRA-A**	**0**		**1550**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**5,509**
18	OBRA	1	1-Jul-92	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	2	11-Mar-68	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	3	13-Oct-68	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	4	16-Jul-69	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	5	30-Jul-71	50	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	6	31-Oct-73	100	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	7	14-Dec-74	100	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	8	15-Sep-75	100	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	9	26-Jan-80	200	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	10	14-Jan-79	200	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	11	31-Dec-77	200	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	12	28-Mar-81	200	STATE	UPRVUNL	THERMAL	COAL	
18	OBRA	13	21-Jul-82	200	STATE	UPRVUNL	THERMAL	COAL	
19	**PANKI**	**0**		**252**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**985**
19	PANKI	1	19-Feb-85	32	STATE	UPRVUNL	THERMAL	COAL	
19	PANKI	2	10-Nov-76	110	STATE	UPRVUNL	THERMAL	COAL	
19	PANKI	3	24-Mar-77	110	STATE	UPRVUNL	THERMAL	COAL	

S_NO	NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2003-04 Net Generation GWh
20	**H_GANJ B**	**0**		**450**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**615**
20	H_GANJ B	1	29-Feb-68	50	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	2	1-Jul-92	50	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	3	22-Jan-72	60	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	4	18-Sep-72	60	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	5	21-Mar-77	60	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	6	26-Aug-81	60	STATE	UPRVUNL	THERMAL	COAL	
20	H_GANJ B	7	31-Mar-78	110	STATE	UPRVUNL	THERMAL	COAL	
21	**PARICHA**	**0**		**430**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**523**
21	PARICHA	1	31-Mar-84	110	STATE	UPRVUNL	THERMAL	COAL	
21	PARICHA	2	25-Feb-85	110	STATE	UPRVUNL	THERMAL	COAL	
21	PARICHA	3	29-Mar-06	210	STATE	UPRVUNL	THERMAL	COAL	
22	**ANPARA**	**0**		**1630**	**STATE**	**UPRVUNL**	**THERMAL**	**COAL**	**10,997**
22	ANPARA	1	24-Mar-86	210	STATE	UPRVUNL	THERMAL	COAL	
22	ANPARA	2	28-Feb-87	210	STATE	UPRVUNL	THERMAL	COAL	
22	ANPARA	3	12-Mar-88	210	STATE	UPRVUNL	THERMAL	COAL	
22	ANPARA	4	19-Jul-93	500	STATE	UPRVUNL	THERMAL	COAL	
22	ANPARA	5	4-Jul-94	500	STATE	UPRVUNL	THERMAL	COAL	
23	**SINGRAULI STPS**	**0**		**2000**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**14,479**
23	SINGRAULI STPS	1	13-Feb-82	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	2	25-Nov-82	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	3	28-Mar-83	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	4	2-Nov-83	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	5	26-Feb-84	200	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	6	23-Dec-86	500	CENTER	NTPC	THERMAL	COAL	
23	SINGRAULI STPS	7	24-Nov-87	500	CENTER	NTPC	THERMAL	COAL	
24	**RIHAND**	**0**		**2000**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**7,347**
24	RIHAND	1	31-Mar-88	500	CENTER	NTPC	THERMAL	COAL	
24	RIHAND	2	5-Jul-89	500	CENTER	NTPC	THERMAL	COAL	
24	RIHAND	3	31-Jan-05	500	CENTER	NTPC	THERMAL	COAL	
24	RIHAND	4	24-Sep-05	500	CENTER	NTPC	THERMAL	COAL	
25	**UNCHAHAR**	**0**		**840**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**5,868**
25	UNCHAHAR	1	21-Nov-88	210	CENTER	NTPC	THERMAL	COAL	
25	UNCHAHAR	2	22-Mar-89	210	CENTER	NTPC	THERMAL	COAL	
25	UNCHAHAR	3	27-Jan-99	210	CENTER	NTPC	THERMAL	COAL	
25	UNCHAHAR	4	22-Oct-99	210	CENTER	NTPC	THERMAL	COAL	
26	**DADRI (NCTPP)**	**0**		**840**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**5,683**
26	DADRI (NCTPP)	1	21-Dec-91	210	CENTER	NTPC	THERMAL	COAL	
26	DADRI (NCTPP)	2	18-Dec-92	210	CENTER	NTPC	THERMAL	COAL	
26	DADRI (NCTPP)	3	16-Jun-92	210	CENTER	NTPC	THERMAL	COAL	
26	DADRI (NCTPP)	4	24-Mar-94	210	CENTER	NTPC	THERMAL	COAL	
27	**TANDA**	**0**		**440**	**CENTER**	**NTPC**	**THERMAL**	**COAL**	**2,650**
27	TANDA	1	23-Jan-88	110	CENTER	NTPC	THERMAL	COAL	
27	TANDA	2	11-Mar-89	110	CENTER	NTPC	THERMAL	COAL	
27	TANDA	3	28-Mar-90	110	CENTER	NTPC	THERMAL	COAL	
27	TANDA	4	20-Feb-98	110	CENTER	NTPC	THERMAL	COAL	
28	**AURAIYA GT**	**0**		**652**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**4,122**
28	AURAIYA GT	1	29-Mar-89	112	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	2	21-Jul-89	112	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	3	9-Aug-89	112	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	4	29-Sep-89	112	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	5	29-Dec-89	102	CENTER	NTPC	THERMAL	GAS	
28	AURAIYA GT	6	12-Jun-90	102	CENTER	NTPC	THERMAL	GAS	
29	**DADRI GT**	**0**		**817**	**CENTER**	**NTPC**	**THERMAL**	**GAS**	**4,930**
29	DADRI GT	1	21-Feb-92	131	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	2	26-Mar-92	131	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	3	6-Jun-92	131	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	4	14-Oct-92	131	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	5	26-Feb-94	146.5	CENTER	NTPC	THERMAL	GAS	
29	DADRI GT	6	27-Mar-93	146.5	CENTER	NTPC	THERMAL	GAS	

6) JAMMU & KASHMIR :

S_NO	NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2006	SECTOR	SYSTEM	TYPE	FUEL 1	2003-04 Net Generation GWh
30	**PAMPORE GT**	**0**		**175**	**STATE**	**JKEB**	**THERMAL**	**DISL**	**29**
30	PAMPORE GT	1	31-Mar-89	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	2	20-Jul-89	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	3	11-Dec-89	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	4	7-Jan-94	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	5	7-Feb-94	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	6	4-Apr-94	25	STATE	JKEB	THERMAL	DISL	
30	PAMPORE GT	7	30-Mar-95	25	STATE	JKEB	THERMAL	DISL	

Both the values of Operating Margin and Build Margin (BM) Emission factors have been considered as below

(Source: Carbon Dioxide Baseline Database, Version 3, 15th December, 2007, published by CEA;http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm).

Calculation the operating margin emission factor according to the selected method Average Operating Margin (OM):

Selected Years	2004-05	2005-06	2006-07
Operating Margin (OM) in tonnes CO_2 / MWh	0.97448	0.99365	0.99202
Average of the Three years in t CO_2 / MWh	0.98672		

Calculation of the Build Margin Emission Factor:

Build Margin (BM)	0.62834 tCO_2 / MWh

Calculation of Combined Margin (CM) Emissions Factor - Emission factor for the Grid electricity:

The baseline emission factor is calculated using the Operating Margin emission factor (*EFOM,y*) and the Build Margin emission factor (*EFBM,y*). The baseline emission factor is the weighted average of the Operating Margin emission factor (*EFOM,y*) and the Build Margin emission factor (*EFBM,y*) .

The applied value of the Operating Margin emission factor and Build Margin emission factor is taken from the section B.6.

So, $EF_y = W_{OM} \text{ X } EF_{OM,\,y} + W_{BM} \text{ X } EF_{BM,\,y}$

Where
- EFy = Combined Margin emission factor
- W_{OM} = Weight Operating Margin
- $EF_{OM,\,y}$ = Operating Margin Emission Factor = 0.98672 tCO_2 / MWh
- W_{BM} = Weight Build Margin
- $EF_{BM,\,y}$ = Build Margin Emission Factor = 0.62834 tCO_2 / MWh

Where, the values of W_{OM} and W_{BM}, by default, are 50% (i.e., $W_{OM} = W_{BM} = 0.5$)

So, $EF_y = 0.5 \text{ X } 986.72 + 0.5 \text{ X } 628.34 = 0.80753 \text{ tCO}_2 / \text{MWh}$

Calculation of Baseline Emission:

The baseline emissions in year y are calculated as:

BEy = EFy x EGy

Where BEy is the baseline emission for the year y (Combined Margin)
EGy is the electricity generation by the project activity in year y,
EFy is the baseline emission factor determined above.

The amount of electricity generated (EGy), has been sourced from Chapter VI: detailed Power Potential Studies, page number (VI -1 to VI 18) of the Detailed Project Report (DPR), which has been approved by the Central Electricity Authority, Government of India. The value has been taken from the DPR; Salient features; page no. s-(iv); 1.4 as 428 GWh, which is equivalent to 428, 000 MWh. The estimation has been shown as below:

The design energy means the quantum of energy which could be generated in a 90% dependable year with 95% plant availability as per Central Electricity Regulatory Commission (CERC) guideline (Source: Page No. : 172; Power: who's who in India - by Federation of Indian Chambers of Commerce and Industry, website: **http://books.google.com/books?id=2wAi374AAfAC&pg=PA173&lpg=PA17&ots=JFfpQNUidZ&dq=definition,+dependable+year,+hydro#PPA172,M1).**

90% dependable year is a year in which the annual energy generation has the probability of equal to or excess of 90% of the expected period of operation of the scheme.

While planning hydro projects, daily discharge data of the river at the project diversion dam site for about continuous 20 years is taken into consideration.

If discharge data for N years is available, the 90% dependable year defined as (N+1) × 90% in the table arranged in descending-discharge order.

If the discharge data of the river for 20 years have been considered, then the 90% dependable year will be

= (20+1) × 90%
= 21 × .9 = 18.9 ~ 19^{th} year

Therefore, 19^{th} year's discharge data, as arranged in descending order will be considered.

The available daily discharge data are converted into '10 daily discharge data' by averaging the daily discharge data for each 10 days. Therefore, there are 36 readings of such '10 daily discharge data' for the year. This '10 daily discharge data' are used for further calculations of power (MW) and design energy generation (MUs) during each of the 10 daily periods. (Please

refer to the Detailed Project Report; Chapter VI; Power Potential studies; Annexure 6.2; page no. VI- 9).

The formula that has been used for power (MW) calculation is as follows:

$$P\ (MW) = \frac{nTG \times 9.81 \times Q \times H}{1000}$$

Where,
P is the power generation in MW
nTG is the combined efficiency of the turbine and generator = 90%
Q is the discharge in cum/ sec.
H is the head in meter available for power generation = Rated head as 608 M

However, the power is restricted to 95% of the installed capacity as per CERC Regulation. If the power from the above formula comes out more than 95% of the installed capacity, the restricted power is considered in energy calculations (Please refer to the excel spreadsheet as provided on Design energy).

The Energy will be calculated as follows:

$E = P \times T$

Where,

E = Energy in kWh
T = Time in hours

Therefore, the estimation of the 10 day energy value is:

$E^{10} = P \times 10 \times 24 = P \times 240$ hours

The summation of 36 readings of the 10 daily energy values of 90% dependable year is the design energy for the project (Please refer to the excel spreadsheet as provided on Design energy).

Again, considering the different discharge values as referred above, the annual generation for different installed capacities has been shown below (Reference: Detailed Project Report; Chapter VI; Power Potential studies; Point 6.3.2; page no. VI-3).

Installed Capacity (MW)	90% Dependable year Energy (GWh)	Incremental Energy Generation /MW Increase of Installed Capacity
70	360.30	
75	372.78	2.50
80	385.84	2.61
85	397.67	2.37
90	409.15	2.30
95	419.60	2.09
100	428.00 (Conservative value)	1.60

105	431.60	0.80
110	433.48	0.38
115	434.62	0.23
120	434.75	0.03

From the table, it can be shown that with the increase of the installed capacity, this is a steady increase in energy generation from 70 MW to 100 MW. The increase in energy generation gets substantially low and beyond economical consideration with increase in installed capacity from above 100 MW to 120 MW. This implies that 100 MW is the optimum installed capacity with an optimum generation of 428 GWh, which is equivalent to 428, 000 MWh, for the project activity. As the design discharge data, which is individual characteristics of each river or stream specific to a location, makes it project specific.

So, BEy = 0.80753 tCO_2 / MWh X 428, 000 MWh = 345, 622 tonnes of CO_2 (tCO_2)

Calculation of the Project Emissions (PEy):

PEy = 0 for this project activity as the value of the power density is 2857 Watt / m^2, greater than 10 W/m^2.

Leakage calculation (LEy):

As per the methodology ACM 0002, Version 07, Sectoral Scope 1, December 14, 2007 (page no. 10/19; Leakage), no leakage has been applied for the project activity.

Hence, LEy = 0.

Calculation of Emission Reduction:

ERy = BEy – PEy – Ly

Where ERy is the Emission Reduction for the year y
BEy is the baseline emission for the year y (Combined Margin)
PEy is the Project Emissions
Ly is the Leakage

According to the ACM0002 methodology, PEy =Ly = 0;

Therefore, ERy = BEy = EFy x EGy = 345, 622 tonnes of $CO_{2\,e}$ (tCO_2) per year.

Annex 4

MONITORING INFORMATION

A CDM project supporting team will be constituted along with participation of Project In charge and plant operators, after suitable training on CDM and its related monitoring activities. The responsibilities of different members of the CDM project supporting team are as follows:

Project In charge	Cross-checking of the report for any requirement of corrective measures.
CDM project supporting team	The monitoring reports will be prepared by the CDM supporting team.

Monitoring:

Monitoring methodology for Electricity generation from the project activities is as below:

Completeness:

One set of Meters comprising (a) a set of Main Meters and (b) a set of Check Meters shall be installed at the interconnection point of the project site and the substation for monitoring of the net amount of electricity supplied to the grid.

Reliability:

All Meters shall be installed by the Company at its own cost. Each Meter shall be of static type. 0.2% accuracy class confirming to latest IEC-687 and shall meet the requirements of IEGC.

One complete spare set of tested, calibrated and sealed Meters shall be kept in safe custody of the Company. All such Meters shall be sealed in the presence of the CTU, PTC and the Company, which seal shall remain intact unless it is broken by the Testing Laboratory for testing and calibration.

Frequency:

Power Trading Corporation (PTC) will conduct the Performance Test as per the Power Purchase Agreement (PPA) during the lifetime, comprising any or all of the following:

(i) Project Capacity Test;
(ii) Maximum Project Capacity Test: and
(iii) Unit Characteristics Test on any Unit but limited to:
  (a) Reactive Power capability: and
  (b) Start up time

All the Main meters, Check Meters and back up meters shall be tested and calibrated by a reputed Testing Laboratory. The Meters (and associated circuits, if necessary) shall be tested and calibrated in accordance with the provisions set out in the Connection Agreement and IEGC. At least once in two (2) tariff years, or at any time when the difference between the readings of the

Main meter and the corresponding Check meters is found to exceed zero point four percent (0.4%). The company shall bear the cost of testing and calibration of the Meters.

Meter reading of the amount of the net electricity supplied from the Main Meters installed at the Interconnection Point shall be taken by the company and the power buyer on monthly basis.

Internal Audit:

A CDM Supporting Team will be responsible for the preparation of the monitoring report based on the net amount of electricity supplied as per the monitoring plan. The monitoring reports will be checked and discussed with the Project In charge, who is a qualified engineer with 10-15 years of experience. In case of any irregularity observed, immediate action will be taken. The monitoring report prepared by the team will be further submitted to the Management on regular basis.

All the above parameters monitored according to the monitoring plan, will be kept for 2 years after the end of crediting period or the last issuance of CERs for this project activity whichever occurs later. The monitored data will be used by the DOE to estimate and verify the emission reductions taking place during the project activity.

Appendix I

As per "GUIDANCE ON THE DEMONSTRATION AND ASSESSMENT OF PRIOR CONSIDERATION OF THE CDM" in Annex 46 in EB 41 Report, proposed project activities with a start date before August 02, 2008, for which the start date is prior to the date of publication of the PDD for global stakeholder consultation, are required to demonstrate that the CDM was seriously considered in the decision to implement the project activity. Malana II satisfies the consideration (Start Date: 18th October, 2006 as per the E & M Contract) and for such demonstration, the following elements need to be satisfied:

Sl No.	**Name of Document**	**Date**	**As per "GUIDANCE ON THE DEMONSTRATION AND ASSESSMENT OF PRIOR CONSIDERATION OF THE CDM" in Annex 46 in EB 41 Report**
1.	Equity Subscription Agreement between Everest Power Private Limited (EPPL) & Green Infrastructure Private Limited (GIPL)	23rd October, 2003	-
2.	Board Meeting Resolutions with CDM Consideration	26th March, 2004	with serious CDM consideration
3.	Publication in Newspaper	8th April, 2004	-
4.	Enquiry placed for providing CDM Consultancy Services	22nd February, 2005	-
5.	Subsequent Agreement to Equity Subscription Agreement signed on 23rd October, 2003	21st March, 2005	with serious CDM consideration
6.	Offer from Prajna Consultancies (PVT) LTD for providing CDM Consultancy Services	15th April, 2005	with serious CDM consideration
7.	Revised Financial Offer from Prajna Consultancies (PVT) LTD	22nd July, 2005	with serious CDM consideration
8.	Work Order issued to Prajna Consultancies (PVT) LTD	12th August, 2005	with serious CDM consideration
9.	Cancellation of Work Order	28th February, 2006	with serious CDM consideration

10.	Board Meeting Resolutions with a mention of hiring EIPL as a Consultant to execute the project	24th March, 2006	Continuation of CDM and real actions taken to secure CDM status
11.	Common Loan Agreement signed between EPPL and all the Lenders based on the Subsequent Agreement to Equity Subscription Agreement. Subsequent Agreement to Equity Subscription Agreement has taken CDM into consideration in a serious manner.	30th August, 2006	with serious consideration of CDM
12.	Consultant Contract between EPPL & EIPL for executing the CDM Project development & Sales of Emission Reductions	18th June, 2007	Continuation of CDM and real actions taken to secure CDM status
13.	Submission of a new methodology to the CDM Executive Board	-	Not Applicable
14.	Interviews with DNA	21st November, 2007	Continuation of CDM and real actions taken to secure CDM status
15.	Earlier correspondence on the project with the DNA or the UNFCCC secretariat	27th December, 2007	Host Country Approval has been achieved from DNA
16.	Evidence of Agreements or negotiations with a DOE for validation services Web hosting of the project	24th January, 2008	Continuation of CDM and real actions taken to secure CDM status
17.	Emission Reduction Purchase Agreements or other documentation related to the sale of the potential CERs (including correspondence with multilateral financial institutions or carbon funds)	31st October, 2008	Negotiation with the Buyers has been completed successfully.