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

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SECTION A. General description of project activity

A.1 Title of the project activity:

Dagachhu Hydropower Project, Bhutan
Version 9.2
Dated 26/08/2013

Revision history of the PDD

Version number	Date of revision made	Remark
7.3	22/02/2010	Final PDD for CDM registration
9.1	12/03/2013	Changed PDD for EB approval (Increase of installed capacity, annual generation and investment costs/schedule)
9.2	26/08/2013	Revised the PLF value from 52% to 46.66%

A.2. Description of the project activity:

The Dagachhu Hydropower Project is a run-of-river hydropower project with an installed capacity of 126 MW (2 units of 63 MW each) with approximate annual energy production of 515 GWh. The overall purpose of the project is the generation of electricity based on renewable energy sources. The electricity will be delivered to the regional grid consisting of Bhutan and the Eastern region of India. The projected income from the sale of CERs will contribute not only to the socio-economic situation of the region but also to sustainable development in Bhutan. Furthermore, the hydro power generated will increase the share of renewable energy in the regional grid.

For Bhutan, the project will add great benefit to the national economy and environmental sustainability through the production and sale of hydropower. Thus, the sale of CERs will contribute to the financial sustainability of Bhutan while reducing CO_2 emissions in the regional grid consisting of the Eastern Indian grid and Bhutan. Furthermore, implementation of this project in Bhutan is carried out within an overall CDM capacity building project, thereby providing the project developer (Dagachhu Hydro Power Corporation Limited – hereafter referred as DHPC) with necessary skills and know-how to utilize its CDM potential for further projects.

At the regional level, the local population currently has limited access to public services, telephone services, roads, water supply and electricity. This project also foresees the construction of a transmission line with a length of 19.5 km as well as new access roads and the upgrading of existing roads. Consequently, a significant improvement of the infrastructure in the region is expected. An improvement in tourism is also anticipated due to these measures. In general, the project will provide significant local social benefits due to additional employment and business opportunities, better road access and electrification of the area.

All of the households in the vicinity of the project area will receive electricity which will drastically improve living conditions. Currently, 91 percent of households use kerosene for lighting and 98 percent use firewood for cooking. According to a study conducted by the FAO Project BHU/99/005 National Strategy for Stoves and Other Alternative Energies, May 2001, the per capita consumption of firewood by

people living between the altitudes ranging from 1200 – 2800m is 3.4kg/head/day. Using this consumption figure, the 4,446 people living within project influence area, which are currently deprived of electricity, roughly consume 15,000 kg of firewood per day. The project will replace firewood consumption and save cutting down of 15 tons of trees per day contributing to the overall environmental sustainability of Bhutan.

The project will also improve sanitary conditions of households through the income generated from the sale of farm products thus improving living conditions. Currently, 99 percent of the households use pit toilets or open defecation which results in a chain of negative effects.

For India, the project will contribute significantly to the achievement of the national sustainability goals:
- Socio-Economic well being: The project will supply power to Eastern Indian grid which will contribute in reducing chronic deficit.
- Environmental well being: The project activity will displace the power which would otherwise be generated from fossil fuel such as coal, diesel, gas etc.

A.3. Project participants:

Name of Party involved	Private and/or public entity (ies) project participants	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Bhutan (host)	Dagachhu Hydro Power Corporation Limited[1]	Yes
India (host)	Tata Power Trading Company Ltd.	No

In its 28th meeting in December 2006, the CDM Executive Board clarified that the word "regional", in the context of "regional electricity system" used in ACM0002, can also be interpreted as extending across several countries. The EB Board further clarified that trans-national electricity systems are eligible under ACM0002 and the DNAs of countries in these regions, across which the electric system spans, shall be considered as host Parties.

In 2006, an agreement was signed between the Royal Government of Bhutan and the Government of India concerning cooperation in the field of hydroelectric power. The two countries shall cooperate in the development of renewable energy and both countries shall support each other to develop projects under the Clean Development Mechanism of the Kyoto Protocol, using a common carbon emission baseline, and any other international mechanisms that may come into force to encourage renewable energy. This agreement therefore provides the basis to support each other in developing CDM projects.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

[1] For the implementation and operation of HPP Dagachhu, the Dagachhu Hydro Power Corporation Limited (DHPC) was founded. The CDM Secretariat was informed accordingly about this change of project participant by sending an updated MoC form.

The Dagachhu Hydropower Project is located in Dagana Dzongkhag (district) in Bhutan, on the Dagachhu River.

A.4.1.1. Host Party(ies):

Bhutan

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

Dagana Dzongkhag (district)

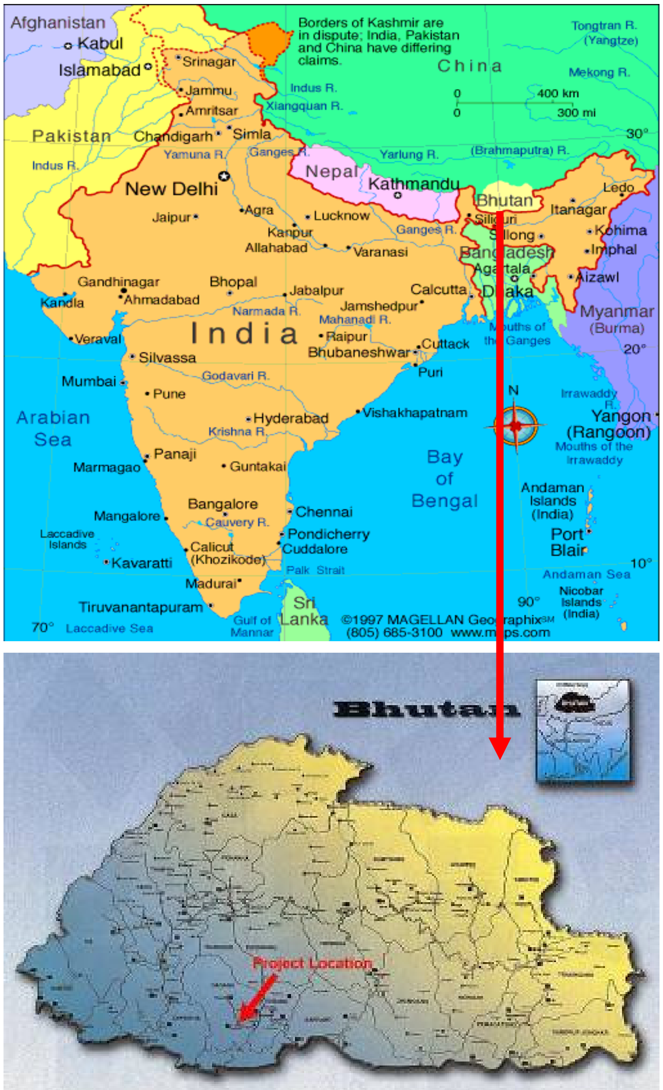
A.4.1.3. City/Town/Community etc:

Dagana Dzongkhag (district)

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

The Dagana Dzongkhag is one of the remotest districts in Bhutan. Its total area is approximately 1400 km² and it lies between 26°50' N to 27°17'N and 89°41'E to 90°5'E. The Dzongkhag falls within the temperate zone in the north and sub-tropical zone in the south, with wet summers and cool and dry winters. About 79% of the total area is covered with forest. The project uses the water of the Dagachhu, which is a tributary stream to the Punatsangchhu (Sunkosh) that drains into the Brahmaputra in India. The total size of the catchment area utilized by the project is 676 km². The elevation within the catchment ranges from approximately 800 m to 4000 m.

The powerhouse is located about 11.5 km upstream of the junction of the Dagachhu and the Punatsangchhu. The intake is about 8.8 km upstream of the powerhouse.



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

Scope Number 1 – Energy industries (renewable), hydropower

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

The proposed project is located at the left side of the Dagachhu River as a run-of-river power plant. The main components of the plant are powerhouse, penstock, surge shaft, headrace tunnel, Desilter, weir/intake and a 220kV transmission line. The powerhouse is located about 11.5 km upstream the junction of the Dagachhu and the Punatsangchhu. The intake is about 8.8 km upstream the powerhouse. The plant has a gross head of 304 m and a design discharge of 50 m³/sec (maximum flow). The two units with Pelton turbines (capacity of 63 MW each) have a combined capacity of about 126 MW and will generate an average yearly output of 515GWh.

The feasibility study for the hydropower plant was prepared by a consulting team comprised of interdisciplinary Austrian experts with extensive know-how in hydropower, ensuring that state-of-the-art technology and hydropower design is incorporated into the project. Due to Austria's similar mountainous topography and long-term experience with hydropower, coupled with environmentally friendly renewable energy technology, a transfer of valuable know-how is made possible.

In order to ascertain the long term sustainability of the know-how transfer, a training program is part of the CDM project activity. The training program is specifically designed to fit the requirements of the Project Authority in order to build up capacity in operation and maintenance of state-of-the-art hydro-electrical equipment. Through the training program, cost optimal operation and maintenance of the hydropower plant can be achieved, maximising the lifetime of the equipment.

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

Emission reductions are estimated using the formula described in Section B.2.
The estimation of the emission reductions is based on an annual output of 515,000 MWh in 2012 and reduced by an linear technical degradation figure ((app. 1,000 MWh less generation from one year to the next year)). This output is used within the regional electricity system including Eastern Indian grid and Bhutanese power plants. The feasibility study (dated July 2006) set the commissioning of the plant for 2011. In the **registered PDD**, the commissioning of the plant was scheduled for the beginning of 2012. Due to the further delays in civil work completion, the project is currently planned to start commercial operations by 01/04/2014. Therefore, emission reductions from April 2014 onwards are considered in the **updated PDD**.

Years	Annual estimation of emission reductions in tonnes of CO_2e
2014	387,766
2015	515,987
2016	514,955
2017	513,925
2018	512,897
2019	511,872
2020	510,848
2021	127,457
Total estimated reductions (tonnes of CO_2e)	**3,595,706**
Total number of crediting years	**7**
Annual average over the crediting period of estimated reductions (tonnes of CO_2e)	**513,672**

A.4.5. Public funding of the project activity:

No public funding is foreseen for the implementation of the Dagachhu Hydropower Project.

SECTION B. Application of a baseline and monitoring methodology

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

Approved consolidated baseline and monitoring methodology ACM0002/ Version 07(EB36), Sectoral Scope 01

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

The methodology ACM0002 is applicable to grid-connected renewable power generation project activities that involve electricity capacity additions. The methodology is applicable under the following conditions:

1. The project activity is the installation or modification/retrofit of a power plant/unit of one of the following types: hydro power plant/unit (either with a run-of-river reservoir or an accumulation reservoir), wind power plant/unit, geothermal power plant/unit, solar power plant/unit, wave power plant/unit or tidal power plant/unit.

The Dagachhu HPP project is the installation of a new hydro power plant and hence matches with the applicability criteria 1.

2. In case of hydro power plants:
   - The project activity is implemented in an existing reservoir, with no change in the volume of reservoir.
   - The project activity is implemented in an existing reservoir, where the volume of reservoir is increased and the power density of the project activity, as per definitions given in the Project Emissions section, is greater than 4 W/m2.
   - The project activity results in new reservoirs and the power density of the power plant, as per definitions given in the Project Emissions section, is greater than 4 W/m2.

The Dagachhu HPP project uses run-of-river hydro power to generate electricity and therefore does not build a new reservoir. There is only a minor size of 0.035 km2 of flooded surface area.[2]due to the project activity. Hence, the Power Density (PD in W/m²)for HPP Dagachhu is calculated by dividing the installed capacity of the hydro power plant (Cap_{PJ} = 126,000,000 W) by this flooded surface area (A_{PJ} = 35,000 m^2):

PD = 126,000,000 W / 35,000 m² = 3,600 W/m²

This is by far above the threshold of 4 W/m². Hence, the project matches with the applicability criterion2.

[2]The data for calculating the Power Density was taken from Chapter 1.2.4. (Table 1-1) of the Environmental Assessment (Enclosure 4 to the PDD).

3. The geographic and system boundaries for the relevant electricity grid can be clearly identified and information on the characteristics of the grid is available;

Criterion 3 is fulfilled, because the geographic and system boundaries of the relevant electricity grid consisting of Bhutan and Eastern Indian grid are clearly identified and the necessary grid data is available.

4. Applies to grid connected electricity generation from landfill gas to the extent that it is combined with the approved "Consolidated baseline methodology for landfill gas project activities"(ACM0001); and

This criterion is not relevant for hydro power plants.

5. 5 years of historical data (or 3 years in the case of non hydro project activities) have to be available for those project activities where modification/retrofit measures are implemented in an existing power plant[2].

This criterion is not relevant for new hydro power plants like the proposed project activity.

The methodology ACM0002 is not applicable to the following:

6. Project activities that involve switching from fossil fuels to renewable energy sources at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels at the site;
7. Biomass fired power plants;
8. Hydro power plants[3] that result in new reservoirs or in the increase in existing reservoirs where the power density of the power plant is less than 4 W/m^2.

As criteria 6 to 8 do not apply to the project activity, the project activity is eligible to be developed as a CDM project under ACM0002.

ACM0002 is designed to be applicable to grid-connected run-of-river hydro power projects and determines the baseline for grid electricity generation at the combined margin. The Project is a renewable energy project that is connected to a predominantly thermal based grid, and is likely to affect the operating margin, and in the long term, the build margin. This is with accordance to what has been laid down in the ACM0002.

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

1) The following list shows the sources and the Greenhouse Gases which are included and excluded in the project boundary:

Source		Gas	Included	Justification/Explanation
Baseline	CO_2 emissions from electricity generation in fossil fuel fired power plants that is displaced due to the project activity.	CO_2	Included	Main emissions source
		CH_4	Excluded	Minor emission source
		N_2O	Excluded	Minor emission source
Project	For hydro power plants, emissions of	CO_2	Excluded	Minor emission source
		CH_4	Included	Main emission source

	CH_4 from the reservoir.	N_2O	Excluded	Minor emission source

2) The **spatial extent** of the project boundary is defined in ACM0002 by a project electricity system which includes the project site and all power plants physically connected through transmission and distribution lines to the CDM project activity and that can be dispatched without significant transmission constraints. ACM0002 refers to the “Tool to calculate the emission factor for an electricity system” (Version 1.0) which uses the same definition. Based on this tool, an electricity emission factor is calculated for this project electricity system.

The “Tool to calculate the emission factor for an electricity system” (Version 1.0) states that if the DNA of the host country has published a delineation of the project electricity system, these delineations should be used.
The DNA of India has published a delineation of the electricity distribution system in India and connected electricity systems, which is available in the Central Electricity Authority (CEA) database, and which is commonly used for CDM projects in India. The CEA database acknowledges the import of electricity from the connected Bhutanese grid by documenting the total power import, as all the Bhutanese projects exported power to India are hydro based (low cost/ must run), hence has not been considered for operating margin calculation for the electricity system. The CEA database provides plant specific information of power plants located in India, but does not provide plant specific electricity generation of the Bhutanese power plants, which is required to calculate BM for the selected electricity system. In order to estimate the grid emission factor for the project activity considering all the power plants connected to the project activity (in Bhutan and India (eastern grid)), the project proponent has used data sourced from the CEA database version 03[3]for plants in the eastern regional grid of India, and Bhutan Annual Power Data Book 2006/07 for plants in Bhutan.

The following criteria can be used to determine the existence of significant transmission constraints:

•Constraint criterion 1: In case of electricity systems with spot markets for electricity: there are differences in electricity prices (without transmission and distribution costs) of more than 5 percent between the systems during 60 percent or more of the hours of the year.

•Constraint criterion 2: The transmission line is operated at 90% or more of its rated capacity during 90% percent or more of the hours of the year.

Where the application of these criteria does not result in a clear grid boundary, use a regional grid definition in the case of large countries with layered dispatch systems (e.g. provincial / regional / national). A provincial grid definition may indeed in many cases be too narrow given significant electricity trade among provinces that might be affected, directly or indirectly, by a CDM project activity. In other countries, the national (or other largest) grid definition should be used by default.
In its 28th meeting in December 2006, the CDM Executive Board clarified that the word “regional”, in the context of “regional electricity system” used in ACM0002 can also be interpreted as extending across several countries. The Board further clarified that trans-national electricity systems are eligible under ACM0002. Furthermore, the Board clarified that the grid emission factor in this context shall be estimated for the “regional electricity system”. (EB28, paragraph 14)

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

Based on this CDM EB clarification and the arguments given below, it is shown that the most appropriate definition of the spatial extension of the project electricity system is **a regional grid consisting of Bhutan and the Eastern Indian grid.**

Delineation by DNA of project electricity system

There is no published delineation of the DNAs of the host countries Bhutan and India regarding the project electricity system, but both DNAs have issued a Letter of Approval to the project activity (Enclosures 2 and 6), hence agreeing with the chosen definition of the project electricity system.

The concept of trans-national electricity between India and Bhutan can also be verified from the Umbrella Agreement signed on 28 July 2006 between government of India and the government of Bhutan (Enclosure 8) which clearly states that "The Government of Bhutan & Government of India agree to facilitate, encourage & promote the development and construction of hydro projects and associated transmission systems as well as trade in electricity between the two countries, both through public & private system participation. The government of India also agrees to a minimum import of 5000 MW of electricity from Bhutan by the year 2020". Both countries agreed to support each other to develop projects under CDM and using a common carbon emission baseline.

Constraint criterion 1

Constraint criterion 1 as given above and described by the "Tool to calculate the emission factor for an electricity system" (Version 1.0) is not applicable for the proposed activity, as there is no spot market in the both countries which could be compared.

Nevertheless, it can be stated that the achievable tariff for power delivery from Bhutan to India (unit cost in Indian Rupees per kWh) is the most important economic key data for the project developer to invest in a HPP project or not. This is standard for all hydro power projects in Bhutan. The electricity export to India is the main driver for the investment decision in Bhutan.

Constraint criterion 2

Since 1961, all power plants built in Bhutan have been built in cooperation with India. Due to the fact that most of the power generated is exported to India, most or all the large hydro projects in Bhutan are either developed with grant assistance from the Government of India or funded by Indian project participants. The power from these projects is used in Bhutan or supplied to India's Eastern Region via transmission lines. As already mentioned above, in 2006 an agreement was signed between Bhutan and India considering cooperation in the field of hydroelectric power (see Enclosure 8). India agreed on minimum import of 5,000 MW from Bhutan in 2020 which guarantees a maximum utilization of the Bhutanese hydro power plants in the Eastern Indian grid. Hence, Constraint criterion 2 is not fulfilled for the proposed project activity as both the producing and the consuming country have committed themselves to improve the transmission lines according to the increased power generation in Bhutan and delivery to Eastern India.

This close bilateral cooperation is also shown in the following figures:

- Bhutanese grid is fully integrated with the eastern grid of India and exports 90% of the total electricity capacity of Bhutan to the eastern grid of India. The installed generation capacity of Bhutan is 1,606 MW (considering the large projects only) and the country's demand is only 157 MW, which substantiates Bhutan's intention of export of power to eastern grid of India .
- Figure 1 with historic data and forecast until 2020 for the Bhutanese electricity generation and the domestic demand. In 2004-05, Bhutan delivered 75% of electricity generated to the Eastern Indian

Grid.[4] According to the supply and demand forecast figures from the Department of Energy/Bhutan and from the Bhutan Power Corporation, some 68% of electricity generated in 2012 and 82% of electricity generated in 2020 will be delivered to the Eastern Indian grid (not including Dagachhu HPP).

Consequently, it can be assumed that power generated by the proposed Dagachhu HPP will be consumed in Bhutan or will be delivered to the Eastern Indian grid without any transmission constraint. As suggested by Tata Power Trading Company Ltd., the power from the Dagachhu HPP will be supplied via high voltage transmission lines to the Eastern regional grid of India. Tata Power Trading Company Ltd. will arrange for power evacuation to the likely beneficiaries there. Figure 2 illustrates the project location in Bhutan and the high voltage transmission grid between Bhutan and Eastern regional grid of India.

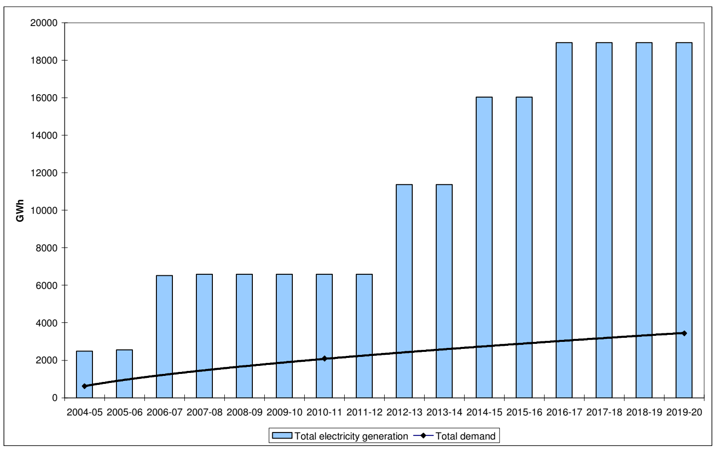


Figure 1 Electricity Supply and Domestic Demand Forecast for Bhutan 2004-2020

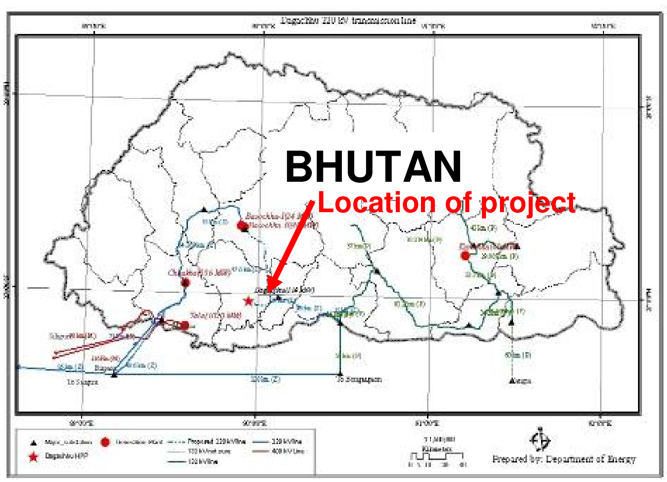


Figure 2 Power grid in Bhutan and Project Location

[4] Source: Department of Energy, Ministry of Economic Affairs, Bhutan

Regional grid definition consisting of Bhutan and Eastern Indian grid

For India as the main consumer of the electricity from the project activity, there are three choices available for choosing the grid to be included to the project electricity system together with Bhutan: national grid, regional grid or state grid.

Power generation and supply within each of the 5 Indian regional grids (East, North-East, North, South and West) is managed by Regional Load Dispatch Centre (RLDC). The Regional Power Committees (RPCs) provide a common platform for discussion and solution to the regional problems relating to the grid. Representatives of the Bhutanese power plants have the observer status in the Eastern Regional Power Committee (ERPC), a common platform for discussion and solution to the regional problems relating to the grid. Considering free flow of electricity among Bhutan and the member states of the Eastern region through the Eastern Regional Load Dispatch Centre (ERLDC), the entire Eastern regional grid and Bhutan is considered as a single regional market for estimation of baseline.

The Eastern Region comprises the States of Bihar, Orissa, West Bengal, Jharkhand. Figure 3 shows the Eastern Region with all relevant data of power plants and transmission lines.

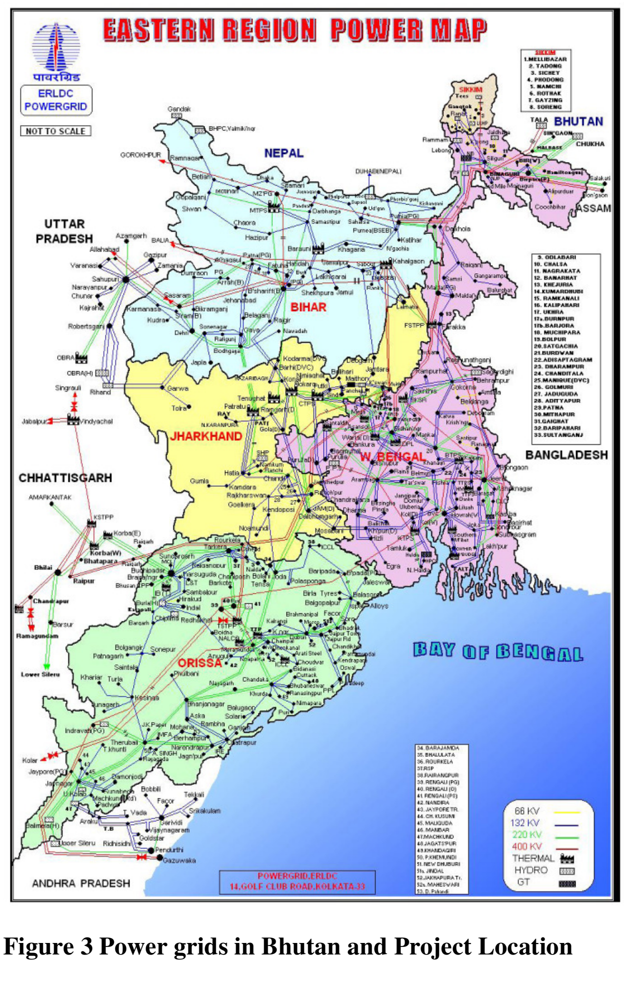


Figure 3 Power grids in Bhutan and Project Location

Additionally, the project electricity system is also connected with other regional grids of India. Electricity transfers from these connected electricity systems to the project electricity system are defined as electricity imports and electricity transfers to connected electricity systems are defined as electricity exports.

Transmission lines between Bhutan and India

Most of the high voltage transmission lines in Bhutan have been built mainly for the purpose of exporting electricity to India. Out of four 400 kV transmission lines that connect the two countries, three are direct links with no provision for supplying power in Bhutan. Similarly of the three 220 kV transmission lines, two are direct connections to India with no substations or inter connections in Bhutan. The existence of the direct transmission lines of 440 kV and 220 kV between Bhutan and India substantiates the fact that a) the two grid are not independent but fully integrated, and hence "trans-national grid" and b) that, there is no transmission constraint.

The project activity envisages for evacuating power to the eastern regional grid of India via the Dajey Substation in Tsirang (220 kV line). The Dajey Substation will be connected to Gelephu Substation in the border from where a 132 kV to India is available. The electricity from the Daggachu project can also be evacuated from the following routes of,

i) Dajey Substation to Rurichhu Substation to Semtokha Substation in Thimphu to down south to Chhukha Substation and then to the eastern grid of India (via three 220 kV lines)
ii) Dagachhu-Dajey-Gelephu to Salakati substation in India
iii) DaganaDajey-Rurichhu-Semtokha-Chhukha to Birpara substation in India.

The existence of the above interconnections can be verified from the eastern region power map of India (Figure 3) and a transmission network map of Bhutan and India from Bhutan Power Corporation limited, a government of Bhutan organisation responsible for electricity transmission in Bhutan (Enclosure 7).

All the above facts substantiate that the eastern regional grid and the Bhutanese grid are not isolated grid systems but constitute a trans-national electricity system. In line with the requirement of the EB28, paragraph 14, India and Bhutan are the Host Parties in the project activity and the DNAs of India and Bhutan have issued the letters of approval for the project activity and also confirmed that the project activity assist in sustainable development of the region.

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

The project involves implementation and operation of the Dagachhu hydro power plant with 126 MW of power delivered to the regional grid.

As per ACM0002, for project activities that do not modify or retrofit an existing electricity generation facility, the baseline scenario is the electricity delivered to the grid by the project that would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources.

The project category is renewable electricity generation for a grid system, which is fed by both fossil fuel fired generating plants (using fossil fuels such as coal, natural gas, etc.) and non-fossil fuel based generating plants (such as hydro, nuclear, biomass and wind). Hence, the applicable baseline, as per

ACM0002, is the kWh produced by the renewable generating unit multiplied by an emission factor (measured in $kgCO_2/kWh$) calculated in a transparent and conservative manner.

Approach
The approach selected in the baseline methodology checks the additionality of the project activity and determines the baseline emission factor for selected baseline scenario.

For grid connected electricity generation projects it is important to ascertain whether the project has some impact on the grid's electricity generating pattern. It has been established in the CDM modalities and procedures that a combined margin (CM) which takes into account the operating margin (OM) and build margin (BM) can be used to determine the effect of the power project to the grid where:

a. The OM is the weighted average of all resources except low-cost/must-run facilities.
b. The BM is the generation-weighted average emission rate of the most recent 20% of plants built (on a generation basis) or the most recent five plants, whichever is greater.

Calculations for this combined margin are based on data from official sources from the Department of Energy for Bhutan[5] and the Indian Central Electricity Authority for the Eastern Indian region[6].

Baseline scenario
In the regional grid consisting of Bhutan and the Eastern Indian grid, electricity delivered to the grid by the project would have otherwise been generated by the operation of grid-connected power plants operational by the addition of new generation sources.

Power Supply Position – Bhutan and Eastern regional grid
The power plants in the regional grid of Bhutan and Eastern Indian generated 98,316GWhof electricity in the financial year 2006-07. The share of hydro power was 13.2% of total generation, the rest (86.8%) was generated at thermal power plants (mainly coal). See Annex 3 for further details of the plants.

The project will generate electricity to the public power grid of Bhutan and the Eastern Indian grid. Hence the hydro power generated from the project site being a must-run facility will replace the electricity generated from thermal power stations feeding into regional grid. Since hydro power is emissions free, the hydro power generated will save the anthropogenic Green House Gas (GHG) emissions that would have been generated by the fossil fuel based thermal power stations comprising coal, diesel, furnace oil and gas.

Identification of Baseline scenario
The methodology lays down certain steps by which the baseline is determined. The baseline methodology identifies the project as being additional and not the baseline scenario. The methodology is designed to have the grid combined margin as the baseline scenario. The proposed hydro power plant will impact the combined margin which is calculated based on the weighted average of the operating margin (OM) emission factor and the build margin (BM) emission factor. Equal weights have been provided to the OM and BM by default as per the norms since the hydro power project is seen to have equal effects on both margins.

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[5] Annual Power Data Book 2006/07 for Bhutan

[6] CO_2 Baseline Database for the Indian Power Sector, Version 3.0 (December 2007)

The project activity does not have any project emissions[7] and does not take leakage into account as per the ACM0002. Hence, the emission reductions that are calculated for the project activity are real.

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):>>

CDM consideration proof

The following lines prove that CDM has always been the main driver for the development of HPP Dagachhu project.

- **2004 – CDM project identification**

Based on opportunities to make a medium sized hydro power project economically feasible with additional CDM revenues, an approval by the Bhutanese Council of Cabinet Ministers (CCM) was conveyed by the Cabinet Secretary vide his letter no. COM/03/04/654 dated 25th March 2004. The project developer identified Dagachhu HPP from the inventory list of hydropower projects as a potential CDM project. To avail the CERs credits under the Kyoto Protocol which is valid until 2012, the CDM Project should be built and made operational well before the 2012 deadline.

- **2005 until mid 2006–preparation of PDD and feasibility study in parallel**

Hence, timing was very critical and the project developer initiated the feasibility study and the development of the Project Design Document (PDD) in parallel within the shortest time possible in 2005. Both documents – final feasibility study report and PDD – were developed until mid 2006.

- **March 2006**

DNV was contracted for validation on 22 March 2006 and the PDD was published in March 2006 for stakeholder consultation.

- **June 2006**

The final report of the feasibility study was finished in June 2006 and stated that the Dagachhu project was considered economically viable under certain circumstances. CDM revenues improve significantly the economic feasibility. The final report also highlighted that next to a Power Purchase Agreement (PPA) also an Emission Reduction Purchase Agreement (ERPA) for CER sale should be signed in order to obtain a more secure basis for the financial analysis. In case of no CDM revenues, the project is only viable with the optimistic assumption that electricity tariffs for the years 2011 to 2014 between 2.50 and 2.90 INR/kWh could be negotiated. And in this case, only the required project IRR, but not the required equity IRR (10%) could be met with these assumptions.

- **25 July 2006**

Due to the specific case of electricity exports from Bhutan to India which was not covered by any approved CDM methodology in mid 2006, DNV sought CDM Executive Board (EB) guidance submitting a "Request for Deviation" In accordance with the CDM EB's guidance, a "Request for Revision" of the ACM0002 was submitted to the Meth Panel on 26 July 2006 (AM_REV_0018). (http://cdm.unfccc.int/UserManagement/FileStorage/KLFMR3XJFMSSJJSYOB9BOETBQRS350)

[7] The "Power Density" (W/m^2) of the project is 3,600 W/m^2 which is by far above the threshold of 10 W/m^2. Therefore, project emissions from the reservoir may be neglected (PE_y=0).

- **31 July 2006 – start of CDM project activity**

Based on the results of the feasibility study, EA and CDM assessment, the Royal Government of Bhutan issued the letter COM04/06/83 dated 31 July 2006 to take up the further development of the Dagachhu hydropower under the condition of CDM development. This can be considered as the first important investment decision and is hence used as the starting date of the CDM project activity.

The validation had already started in March 2006, four months before this investment decision was taken; also the request for revision had been submitted by DNV to the Meth Panel before the investment decision was taken. Hence, the chronology of the project development proves that CDM was seriously considered in the decision to proceed with the project activity.

- **10 November 2006**

Without a final decision from the Meth Panel regarding AM_REV_0018, still in autumn 2006, the Bhutanese government had to approach the Austrian government to ask for a soft loan. In the respective letter from the Bhutanese Finance Minister dated November 10, 2006, it is stated that due to the framework conditions the project would require soft term financing to be viable. The answer of the Austrian government was that only a commercial loan is possible due to the changed framework conditions in Bhutan (see also Step 3 – Barrier Analysis).

Additionally, the higher electricity price estimations within the feasibility study for 2011 to 2014 have been proven to be much too optimistic. For example, the proposed tariff which is currently under negotiation between Bhutan and Tata Power is only 2.35 INR/kWh for 2012; this is much below the price level of 2.50 to 2.90 INR/kWh which was assumed in the feasibility study. Additionally, the feasibility study did not consider the royalty of 12% to 18% of annual power generation which has to be given for free to the Bhutanese state (based on Bhutan Sustainable Hydropower Policy 2008, Clause 4.6.2). This additional cost factor would have decreased the project IRR even more below the required hurdle rates.

- **23 October 2007 - 21 November 2007**

In 2007, the project developer decided to define the grid system boundary in accordance with CDM EB's decision on ACM0002 in December 2006 (EB28 paragraph 14), which allows to define a grid consisting of Bhutan as well as the Eastern Indian grid as one regional electricity system. Due to the new boundary definition, the PDD was re-published for stakeholder consultation in October/November 2007 following ACM0002 Version 7.

- **3 September – 2 October 2008**

In 2008, the importance of CDM revenues increased further for the implementation of the project. The financial closure and the planned signature of the EPC contract were further delayed without a clear CDM status. ADB highlighted this issue in an e-mail to the project developer in September 2008 that ADB loan agreement would include a mandatory requirement for signing the emission reduction underwriting contract which could be only effective based on the CDM validation and registration at UNFCCC.
Due to these project delays and a new version of ACM0002, the PDD had to be re-published in September/October 2008 based on ACM0002 Version 7.

All these facts show that CDM revenues were always considered crucial to ensure the project viability. Uncertainties regarding CDM revenues are one of the main reasons why the project implementation planned for 2011 has been delayed.

In July 2009, the CDM validation was successfully finalized; on 22/07/2009, the DOE uploaded all CDM documents to the UNFCCC website in order to start the request for registration. Shortly after this CDM milestone, the project developer was able to sign the EPC contract on 27/07/2009 which included a technical option to increase the installed capacity from 114 MW to 126 MW due to design optimization. The simulation of the annual generation conducted by the technology provider showed a slight potential increase from 500 to 515 GWh p.a. (3% of annual generation).

The CDM project was successfully registered on 26/02/2010.

In the 11th meeting of the DHPC board on 23/11/2010 it was decided that due to the increased installed capacity the registered PDD has to be updated using the permanent changes of the project design. The increase of installed capacity also caused an increase of the annual generation and investment costs. The construction schedule was also changed and hence the start of operation was delayed.

The additionality of the project activity is further demonstrated and assessed according to the applied methodology ACM0002 using the latest version of the "Tool for the demonstration and assessment of additionality" (Version 05.2) agreed by the CDM Executive Board. The tool provides a step-wise approach to demonstrate and assess additionality of the Dagachhu hydro power plant (HPP) and is applied by completing the following steps within this section:

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

Step 2: Investment and sensitivity analysis to determine that the proposed activity is not the most financially attractive or is unlikely to be financially attractive;

Step 3: Barriers analysis to prove that there is at least one alternative scenario, other than the proposed CDM project activity, not prevented by any of the identified barriers;

Step 4: Common practice analysis to show essential distinction between the proposed CDM project activity and similar activities.

For the project activity, both Step 2 and 3 are completed in order to give a sound overview of the project framework. Based on information about activities similar to the proposed activity, the common practice analysis is to complement and reinforce the investment and barrier analysis.

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

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

It is required to identify realistic and credible alternative(s) that were available to the project developer or similar project developers that provide output or services comparable with the project activity. These alternatives are required to be in compliance with all applicable legal and regulatory requirements.

The demand of electricity in India is expected to grow significantly over the next decades. In order to meet this future demand, India will increase its production capacity utilising all sources of generation facilities including thermal energy (coal, gas, oil) as well as renewable energy sources. On the other hand, Bhutan is generating surplus electrical energy which can be exported in order to cover the increasing demand in India.

The following plausible project alternatives to the proposed project activity were identified which include all possible courses of actions that could be adopted in order to produce an equivalent amount of electrical energy (515GWh p.a.) for the regional grid comprising Eastern Indian grid and power grid in Bhutan.

Project Alternative 1 – Equivalent capacity of thermal (fossil fuel) based power plant, supplying power to the present grid mix
In this scenario the end user would get power from the grid mix consisting of an additional thermal power plant along with the present generation mix. Replacing the planned energy generation (515GWh p.a.) with a thermal power plant would require an installed power of app. 60MW. Due to the fact that Bhutan does not have any oil, gas or coal resources, this project option would be implemented in the Eastern regional grid of India. The increased thermal capacity would lead to an increase in the amount of carbon dioxide from the generation mix for equivalent electricity.

Project Alternative 2 – Equivalent capacity of renewable energy based power plants, supplying power to the present grid mix
In this scenario the end user would get power from the grid mix consisting of additional renewable energy power plants installed in the regional grid comprising Eastern Indian power grid and Bhutanese grid along with the present generation mix. Replacing the planned energy generation (515GWh p.a.) with other renewable energy sources (hydro, wind, photovoltaic, biomass, etc.) would not increase the amount of carbon dioxide from the generation mix for equivalent electricity.

Project Alternative 3 – Present Grid Mix (proposed project activity not undertaken)
In this scenario the end user would get electricity from the current grid mix which consists of a mix of thermal (coal, lignite, natural gas, diesel and heavy oil), hydro, nuclear and other renewable energy based power plants through increased production. An equivalent amount of carbon dioxide at the current emission factor would be generated.

Project Alternative 4 – Project activity not undertaken as CDM project activity
In this scenario the end user would get power from the grid mix consisting of a run-of-river HPP along with the present generation mix. However, as will be shown in this additionality analysis, the implementation of this alternative is very unlikely.

Sub-step 1b –Consistency with mandatory laws and regulations
All the alternatives identified above are in compliance with applicable rules and regulations in Bhutan and India. Therefore, the proposed project activity is in competition with several other forms of energy generation in order to meet the growing demand in India. The proposed project emits the least GHG emissions at the highest cost of generation compared with the alternatives mentioned. This will be shown in detail in the following steps.

Step 2 – Investment analysis

Determine whether the proposed project activity is not:

(a) the most economical or financially attractive; or
(b) Economically or financially feasible, without the revenue from the sale of certified emission reductions (CERs)

Sub-step 2a - Determine appropriate analysis method
Considering the options which are available to analyze the additionality of the Dagachhu HPP project (i.e., simple cost analysis, investment comparison or benchmark analysis), the benchmark analysis is the most appropriate option.

The benchmark analysis has been chosen because that evaluation criterion is used by the project developer to decide whether or not to implement the project. The simple cost analysis is not appropriate because the project will derive economic benefits (e.g. revenues from the sale of energy produced by the project), other than CDM related income.

An investment comparison was also not suitable because the project was not compared to any other investment alternatives (as defined in Step 1) by the project developer (DHPC).
The option to develop the project came up through the opportunity to generate emission certificates in addition to electricity for hydro power plants in Bhutan. It will be shown that the CDM revenues allow Bhutan to sell electricity to India at a competitive price.

For the investment decision, the project developers evaluated the electricity market and regulation in the regional grid; the economics of the Project, the feasibility and advantages of participating in a scheme such as the CDM as well as other criteria. The alternative course of action for Bhutan would be investments in infrastructural projects, other than energy generation as will be shown in Step 3 (Barrier analysis). Nevertheless, the evaluation of the generation cost (INR/kWh) was made against the benchmark of achievable electricity tariff for power export to India.

Sub-step 2b – Option I. Apply simple cost analysis
Not applicable. The Project produces economic benefits other than just the CDM related income.

Sub-step 2b – Option II. Apply investment comparison analysis
Not applicable. The investment decision was not based on a choice between multiple project opportunities.

Sub-step 2b – Option III. Apply benchmark analysis
4. "Identify the financial indicator most suitable for the project type and decision context"
The decision by the project developer of whether or not to invest in the project was based on an evaluation of the project against several benchmark criteria.

The economic benchmark used by the project developer in its decision whether or not to implement the project is if the Project Internal Rate on Return (IRR) with the achievable electricity tariff can cover the Weighted Average Costs of Capital (WACC) for Dagachhu HPP.

5. "Financial/economic analysis shall be based on parameters that are standard in the market, considering the specific characteristics of the project type"
The achievable tariff (INR/kWh)for power delivery from Bhutanese hydro power plants to the Eastern Indian grid is the relevant parameter for the project developer to calculate the Project IRR and to decide whether to invest in a HPP projector not. This is standard for hydro power projects in Bhutan.

6. Based on the experience from Power Purchase Agreements (PPA) negotiated recently with the Indian authorities (e.g. the PPA for Chhukha HPP), the maximum achievable tariff for energy export to India

was 2 INR/kWh in 2005, considering an annual tariff increase of app. 2%, the achievable tariff in 2012 (projected commissioning date of the Dagachhu HPP) would be then 2.30 INR/kWh.

The tariff for Tala hydro power plant which is the newest power plant in Bhutan and started operation in 2006 is 1.80 INR/kWh with an increase of 10% every 5 years until the loan repayment and thereafter an increase of 5% every 5 years.

A first price indication in the draft Term Sheet for HPP Dagachhu signed by the project developers and Tata Power Trading Company in February 2008, sets a tariff of 2.40 INR/kWh in 2012 with a minimum discount of 2% for prompt payment. This leads to an effective achievable price of 2.35 INR/kWh in 2012 which is then increased by 2% annually.

In order to be conservative, the highest tariff of 2.35 INR/kWh in 2012 was used in the PDD as the achievable electricity tariff for the calculation of the Project IRR.

In the updated PDD, the tariff is not changed as the agreed tariff (2.35 INR/kWh for 2012) is still valid.

Sub-step 2c - Calculation and comparison of financial indicators:
7. "Calculate the suitable financial indicator for the proposed CDM project activity"

The following table shows the Project Internal Rate of Return (IRR) with and without CDM related income with the achievable electricity tariff (2.35 INR/kWh in 2012 with 2% annual increase) and is calculated based on a comprehensive forecast of the cash flows throughout the project's assumed useful life of thirty (30) years (30 years is the maximum which can be considered for licencing based on Electricity Act of Bhutan 2001, Clause 31.1).

Table 1: Project Internal Rate of Return (IRR) of Dagachhu HPP with and without CDM revenues

	Case 1: Without CDM related income	Case 2: With CDM related income
Registered PDD: Project IRR	8.79%	10.16%
Updated PDD: Project IRR	5.81%	6.91%

In the updated PDD, the resulting project IRR is significantly below the value in the original PDD. The reason is that the additional generation due to the increased installed capacity is much lower than the additional investment costs. Therefore, the project has become financially less attractive than described in the registered PDD.

The Project IRR is then compared with the Weighted Average Cost of Capital (WACC) for the Dagachhu project (9.4%). It can be demonstrated that without CDM revenues the project would be below the required benchmark. Additional CDM revenues would make the project economically viable.

8. "Present the investment analysis in a transparent manner".

Case 1-without benefit of CER sales
Case 2-with benefit of CER sales

The cash-flow analysis was carried out utilizing standard formulas for calculating the Project Internal Rate of Return (IRR) and Net Present Value (NPV). The input data can be summarized as follows:

Table 2: Input data for investment analysis as used in the Feasibility Study 2006 or updated in the ADB due diligence

	Unit	Amount	Source
Share of equity	%	40	ADB Draft Due Diligence
Tax rate	%	30	Feasibility study final report
Average cost of debt raised from various sources considering the access to export financing arrangements offering interest rates below market levels	%	9.0	Feasibility study final report
Repayment period of debt	Years	15	Feasibility study final report
Required return on equity (post tax)	%	10	Bhutan Electricity Authority BEA -001 2006
Years of operation and concession	Years	30	Feasibility study final report
Operation and Maintenance costs (fixed)	% of total investment cost	1	Feasibility study final report
Annual escalation in fixed O&M costs	%	4	Feasibility study final report
Variable O&M costs (transmission costs)	Nu./kWh	0.125	Feasibility study final report
Annual capacity degradation	% of annual generation	0.2%	Feasibility study final report
Royalty (electricity given for free to the Bhutanese state)	% of total generation 2012-2024 after 2024	 12 18	Bhutan Sustainable Hydropower Policy 2008, Clause 4.6.2
Benchmark electricity tariff (Basis 2012)	INR/kWh	2.35	PPA with TPTCL
Annual increase of electricity price	%	2	Feasibility study final report
CER price after 2012	EUR	6.5	Market survey assumption
Exchange rates	INR/EUR INR/USD INR/NU	66 40.5 1	Exchange rate Sept 08 ADB Draft Due Diligence

The following project data has been updated due to permanent changes in the project design:

	Unit	Value Original PDD	Source	Value Updated PDD	Source
Installed capacity	MW	114	Feasibility final report	126	MoM of 11th DHPC board meeting (23.11.2010), pages 19-20
Power generation in first year of operation	GWh	500	Feasibility final report	515	MoM of 11th DHPC board meeting (23.11.2010), pages 19-20
Start of operation	Month/year	01/01/2012	ADB Draft Due Diligence	01/04/2014	Revised Project Implementation Schedule dated 23/05/2012
Investment volume including interest during construction (IDC) and ECG Premium	Nu. Million	8,160	ADB Draft Due Diligence	11,600	MoM of 1st EOGM dated 08/09/2012 (page No. 2)
Investment volume excluding IDC and ECG premium[8]	Nu. Million	7,585	ADB Draft Due Diligence	10,837	MoM of 1st EOGM dated 08/09/2012 (page No. 2)
Schedule of investment costs excluding IDC	Nu. Million	2008: 1457 2009: 2934 2010: 1192 2011: 2003	ADB Draft Due Diligence	2007: 2 2008: 250 2009: 1213 2010: 2131 2011: 1834 2012: 3675 2013: 1114 2014: 617	MoM of 1st EOGM dated 08/09/2012 (page No. 2)

In the original PDD, after due diligence carried out by ADB (2008), the project cost was estimated at Nu. 8,160 million. The DHPC Board in its 1st EOGM (08/09/2012) approved a revised Project Estimate of Nu. 11,600 million in consideration of the increased installed capacity and the final EPC agreement values.

Based on the input data, the following parameters and cash flows were calculated:

Weighted Average Cost of Capital:

The benchmark Project IRR is based on the financing structure of the project (mixture of equity and debt) is calculated in the following way:
WACC = Return on equity after tax * equity + (1-equity) * Cost of debt
WACC = 9.4 %

[8] For the calculation of the project IRR, IDC and the ECG premium are not considered.

The Project IRR is calculated in the following way using the achievable electricity tariff of 2.35 INR/kWh in 2012 with 2% annual increase.

Calculation of Net Profit:

= Turnover	
+ Electricity	
+ CERs	
- Cost of electricity sold	
CER Costs	
- O&M Costs	
Variable	
Fixed	
= EBITDA	
- Depreciation	
= EBIT	
- Interests	
= EBT	
- Taxes	
= Net Profit	

Calculation of Cash flows:

+ EBIT	
+ Depreciation	
- Taxes	
- Investment (without IDC)	
= Free cash flow (FCF)	

Calculation of NPV and IRR:

$$NPV = \sum_{i=1}^{30} \frac{FCF_i}{(1+WACC)^i} \qquad 0 = \sum_{i=1}^{30} \frac{FCF_i}{(1+IRR)^i}$$

Finally, the resulting Project IRRs for the cases with and without CDM revenues are compared with the WACC of 9.4%.

9. The only difference in assumptions between Case 1 and Case 2 in Table 1 above is the addition of revenue related to the sale by the project of CER's.

10. Table 1 above shows the Project IRR for the project based on two different scenarios. In Case 1, the Project does not receive any CDM related income. In the registered PDD, the Project IRR is only 8.79% which is below the benchmark of 9.4%. In Case 2, it is assumed that the Project will receive CDM related income in addition to energy revenues. When the additional income is factored into the cash flow projections, the project is able to achieve a Project IRR of 10.16% which is above the benchmark of 9.4%.

In the updated PDD, the resulting project IRR is significantly below the values in the registered PDD (5.81% without CDM, 6.91% with CDM revenues) as the increased investment costs (+42.15%)are significantly higher than the additional revenues due to the increased annual generation (+3%).

Sub-step 2d - Sensitivity analysis (only applicable to options II and III):
11. Please refer to the table below for a sensitivity analysis for Cases 1 and 2.

Table 3 shows how much the key parameters have to be deviated in order that the Project IRR of Case 1 (without CDM revenues) meets the benchmark of 9.4%.

Table 3: Required deviations of key parameter in order to meet the benchmark IRR

	Case 1 Without CDM related income	
	Registered PDD	**Updated PDD**
Assumption Tested	**Deviation from Base Case**	**Deviation from Base Case**
Investment deviation	-5.7%	-35.8%
Energy Generation deviation	+7.1%	+55.1%
O&M cost deviation	-37.8%	-131.6%
Electricity price deviation	+6.4%	+51.2%

The table above shows, that in Case 1 (without CER revenues) the project meets the benchmark of 9.4% Project IRR only if the project performance is significantly enhanced. None of these deviations are realistic due to the following reasons.

In the registered PDD, the following reasons are given:
It is assumed that the investment costs taken for the cash-flow analysis are already a low figure due to the following facts:

- The investment cost figure (201.5 m USD or 8,160 m NU) used within the PDD is taken from the currently ongoing ADB due diligence and is already a conservative and low figure. It is lower than the investment costs used in the feasibility study in 2006 (152 m EUR or 8,208mNU) due to the changes in the exchange rate between the currencies.
- Recently, power plant technology suppliers have significantly increased their EURO prices for their products, mainly due to high demand for power plants, high steel and energy prices and high inflation in the production countries.
- It is proposed to implement the project through EPC contractors. EPC contract costs are generally higher than the estimated project cost as risks are factored in the bid price. Draft figures from the ongoing EPC contract negotiations show significant higher investment costs (>20% higher) than estimated in the feasibility study or ADB due diligence.
- Hence, the final investment decision with the financial closure and the signature of engineering, procurement and construction contracts – which was planned for December 2008 – has been delayed as under current circumstances (e.g. no CDM registration so far) the project is not feasible.

Hence, the **registered PDD** stated that a decrease of investment costs by 5.7% in order to meet the benchmark IRR without CDM revenues is not realistic.

The investment costs used in the **updated PDD** are already based on final EPC agreement and Civil agreement, hence significantly reducing the cost uncertainty. Hence, a decrease of these investment cost by 35.8% in order to meet the benchmark IRR without CDM revenues is not realistic.

The following table[9] proves the different annual generation results, but a stable and slightly decreasing trend in hydrological conditions for HPP Dagachhu in the last years can be documented.

The highest values are reported for the years 1990, 1998 and 2000, the lowest values are in 1996, 2002 and 2003.

Please take note that this table is based on 114 MW installed capacity which was the assumption of the feasibility study. As an approximation for the 126 MW case, the additional 15 GWh of annual generation (515 instead of 500GWh p.a.) has been added to the annual and 5-year average values for the 114 MW.

Table 4: Estimated annual energy generation based on hydrological data 1990-2004

Year	Energy Generation for 114 MW	5-year-average for 114 MW	Energy Generation for 126 MW	5-year-average for 126 MW
	[GWh]	[GWh]	[GWh]	[GWh]
1990	676	496	676+15=691	496+15= 511
1991	564		564+15=579	
1992	403		403+15=418	
1993	404		404+15=419	
1994	435		435+15=450	
1995	560	508	560+15=575	508+15= 523
1996	359		359+15=374	
1997	463		463+15=478	
1998	663		663+15=678	
1999	495		495+15=510	
2000	655	493	655+15=670	493+15= 508
2001	591		591+15=606	
2002	387		387+15=402	
2003	360		360+15=375	
2004	472		472+15=487	
Average	**499**		**499+15=514**	

In the **registered PDD**, the average figure would have to increase to above 535GWh in order to meet the benchmark IRR of 9.4%. In 9 out of the reported 15 years, the annual generation has been lower. The average energy generation for the whole period 1990 to 2004 is 499 GWh/year. Also, if you analyse a 5-year-average, the values have always been far below the required 535 GWh per year. The ADB due diligence confirmed the 499 GWh average annual generation as reasonable.

The simulation of the plant operation with the increased installed capacity (126 MW instead of 114 MW) was conducted by the technology supplier. The resulting annual generation is 515 GWh, hence only 3% above the value considered in the registered PDD (500 GWh).

[9] Source for the first three columns: Feasibility study Table 4.11: Annual energy generation estimated for the period 1990-2004

In the **updated PDD**, the average figure of 515 GWh would have to increase to above 799 GWh in order to meet the benchmark IRR of 9.4%. In the reported 15 years, the annual generation has always been lower. Concluding, individual years could be above the 799GWh benchmark due to the fact that the run-of-river power Dagachhu HPP does not have storage capacity, but it is very unrealistic to assume that the average energy generation will be above 799 GWh (55.1% higher than the assumed 515 GWh).

In the **registered PDD**, it is considered by far not realistic that the O&M costs will decrease by more than 37.8% in order to meet the benchmark tariff. In the **updated PDD**, the O&M costs would need to decrease by more than 100% which is impossible.

Finally, it can also be shown that it is not realistic to assume that the electricity tariff for HPP Dagachhu can reach the necessary tariff benchmark in order to achieve the required IRR of 9.4%.In the **registered PDD**, the tariff benchmark was 2.50 INR/kWh in 2012 with 2% annual escalation and in the **updated PDD** this benchmark is 3.78 INR/kWh.

The Draft term sheet signed between project developers and Tata Power Trading Corporation in February 2008 sets a significant lower tariff indication for 2012 (2.35 INR/KWh plus an annual escalation of 2%[10]).This figure is already significantly above the tariffs which have been recently negotiated for other Bhutanese hydro power plants, e.g. 2.0 INR/kWh for Chukkha power plant in 2005 or 1.80 INR/kWh for Tala power plant in 2006.

It has also to be kept in mind that the Bhutanese power plants compete with power plants in India and that the tariff acceptable for power purchasers in India is independent from generation technology (i.e. hydro, thermal, nuclear, etc.). Hence, the Dagachhu tariff has to be compared with recently negotiated tariffs for new power plants in India, e.g. the tariff for the 4,000MWUltra Mega Power Project (UMPP) Tilaiya in Jharkhand (Eastern Region) with 1.77INR/kWh.[11]The other three UMPP projects in India awarded so far to developers have received tariffs of 1.19, 1.91 and 2.26 INR/kWh respectively.[12]

Hence, it is not realistic to assume that the electricity tariff for HPP Dagachhu can reach the necessary tariff benchmark (3.78 INR/kWh in 2012 with 2% annual escalation) as it would not be competitive in the Indian market.

Hence the conclusion – in the **registered PDD** as well as in the **updated PDD** – that the project does not meet the benchmark requirement without the CDM related revenues is robust to reasonable variations in the critical assumptions. The project is unlikely to be the most financially attractive alternative in terms of cost and profitability.

Additionally to the analysis of the Project IRR, also the annual unit cost of generation has been calculated and then compared with the achievable electricity tariff. This calculation analyses total costs of generation for each operation year individually by summing up all cost positions (O&M, depreciation, taxes, debt interests and costs of equity) and dividing them by the amount of electricity for sale.

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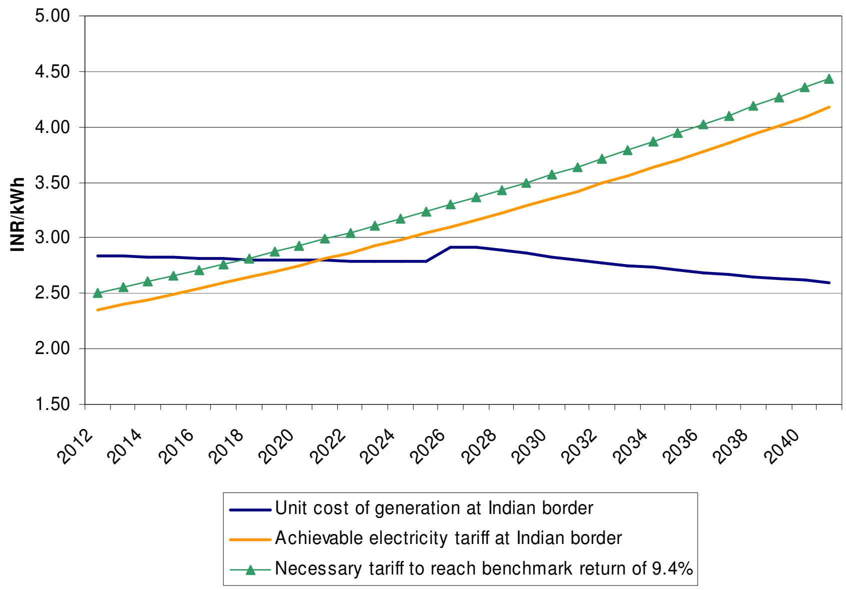
[10] This tariff is still valid when the PDD was updated (May 2012).

[11]http://www.business-standard.com/india/news/reliance-power-bags-tilaiya-project/16/45/53782/on.

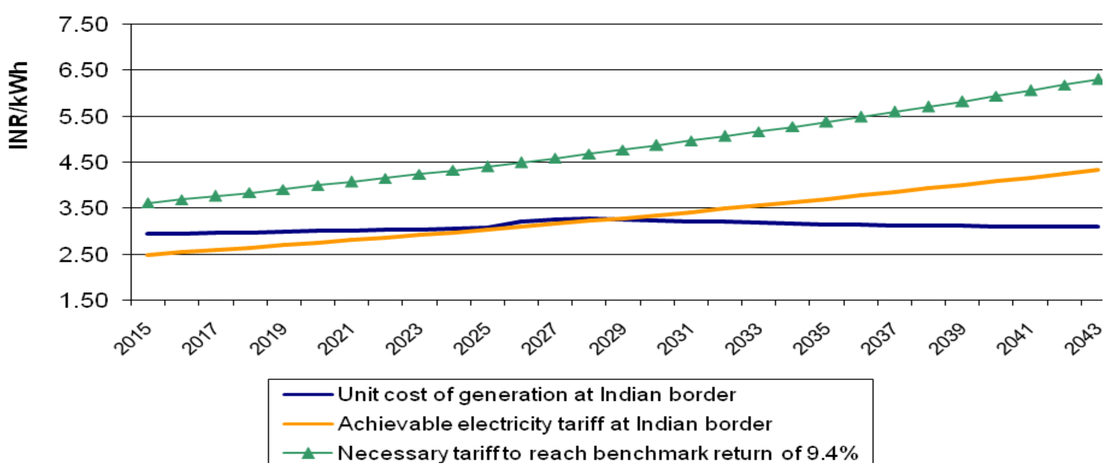
[12]http://news.webindia123.com/news/articles/India/20080613/973605.html, http://timesofindia.indiatimes.com/articleshow/843633.cms

The result in the figure below shows that the unit cost of generation is higher than the achievable electricity tariff in the first years (**registered PDD**: first 10 years 2012-2021, **updated PDD**: until 2028). Only after that, the unit cost of generation can be covered by the achievable tariff. The benchmark electricity tariff (**registered PDD**: 2.50 INR/kWh with 2% annual escalation, **updated PDD**: 3.78 INR/kWh + 2%) to achieve the required IRR of 9.4%, is also given in the following figure:

REGISTERED PDD:



UPDATED PDD:



Step 3 - Barrier Analysis

In addition to economic and financial barriers, the Dagachhu HPP project faces barriers that could readily prevent the implementation of a project of its type, and significantly impact the ultimate development and economics of the project. Among other impacts, the barriers restrict the availability of financing options for the project. At the same time, these barriers would be much less likely to prevent the implementation of alternative projects to generate an equivalent amount of energy in the regional grid consisting of Eastern region of India and Bhutan – namely coal fired or natural gas power plants or renewable power plants (Sub-step 1a – Project Alternatives 1 and 2).

Sub-step 3a - Identify barriers that would prevent the implementation of type of the proposed project activity:

1. Bhutan, one of the least developed countries in the world, relies heavily on foreign aid for financing infrastructure projects. All major projects in Bhutan in the areas of health, education, transport and energy have at least been partially financed through development finance institutions or bilaterally through development grants. As Bhutan gradually improves its development status, the access to donor and development funding becomes increasingly difficult for larger scale infrastructure projects. Furthermore, Bhutan wants to decrease its dependency on foreign aid specifically in the energy sector by attracting foreign equity investors and/or commercial financing institutions.

Nevertheless, commercial term financing faces huge barriers in Bhutan due to the unfavourable risk profile of the country. Many times commercial banks are reluctant to finance infrastructure projects in Bhutan or require unreasonable high risk premiums making projects which require long repayment periods financially unfeasible.

This fact is supported by the external debt statistics of Bhutan (see Table 5), where commercial debt only plays a minor role (less than 4% of the total convertible currency debt outstanding).

Table 5: Bhutan external debt outstanding

BHUTAN EXTERNAL DEBT OUTSTANDING BY INDIVIDUAL CREDITOR CATEGORIES

Creditor Category	1995/96	1996/97	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	Dec'04
	(In millions of USD and Rupees/Ngultrum)								
I. Convertible Currency Debt	**80,2**	**84,0**	**98,7**	**98,7**	**106,9**	**129,9**	**176,8**	**216,0**	**242,6**
a. Multilateral	**74,5**	**80,6**	**88,3**	**88,3**	**94,4**	**107,7**	**142,0**	**157,5**	**172,9**
ADB (Asian Development Bank)	31,2	36,3	43,2	43,2	47,4	55,4	75,8	82,4	90,6
EFIC (Australia)	0,8	0,8	0,5	0,5	0,4	0,3	0,2	0,1	0,0
IFAD (Intl. Fund for Agricultural Development)	10,9	11,4	12,7	12,7	12,5	13,7	19,6	20,3	21,1
KFAED (Kuwait Fund for Arab Economic Development)	11,1	10,9	7,9	7,9	6,5	5,1	3,6	2,1	1,7
IDA (International Development Association of the World Bank)	20,5	21,3	24,0	24,0	27,6	33,2	42,9	52,5	59,5
b. Bilateral	**0,0**	**0,0**	**10,4**	**10,4**	**12,6**	**22,2**	**34,7**	**50,5**	**60,7**
Government of Austria	0,0	0,0	10,4	10,4	12,6	22,2	34,7	50,5	60,7
c. Commercial Debt	**5,7**	**3,4**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**8,0**	**9,0**
II. Rupee Debt	**1256,7**	**1243,8**	**2197,9**	**3276,9**	**6024,4**	**7803,6**	**10963,7**	**14222,3**	**15681,5**
Government of India	1256,7	1243,8	2197,9	3276,9	6024,4	7803,6	10963,7	14222,3	15680,5
State Bank of India	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
Amex Bank	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1,0

Source: Department of Aid and Debt Management, Bhutan

Risk factors that are unique to the proposed Dagachhu HPP project directly contribute to barriers in the project's ability to raise debt financing. Risk factors may be assigned generally to "country risk" – the real or perceived risk of doing business in Bhutan, and to specific risks associated with a particular project. The main lending terms and conditions for a typical large scale project include the interest rate spread over an international interest rate indices (often LIBOR), minimum debt service coverage ratios for defaults and cash distributions, the lenders ability to withdraw cash from the project (sweep policies),

contingency reserve requirements and lender's origination costs, among others. The degree to which these terms and conditions become unfavourable to the borrower are magnified across the board for this project due to the Bhutanese country risk and other barriers/risk unique to the project itself.

The impact of the risks associated with the Project is significant, as it shapes the availability and pricing of potential debt funding for the project. This leads to increased unit costs of energy (INR/kWh) for the project that does not meet the investor's benchmark levels and threatens the project's viability. Securing CDM eligibility would materially improve the strength of the Dagachhu HPP project and help to establish its long-term fiscal feasibility in terms of reaching unit costs of production below the benchmark of 2.35 INR/kWh. Qualifying for CDM would improve the financial feasibility and thereby removing barriers to investment.

Other barriers imposed by risk are especially relevant to and amplified for projects with the characteristics of hydropower projects in general and with the proposed Dagachhu HPP in particular. Generally; projects having high capital costs and long development timelines tend to be more sensitive to risk. More specifically, the risk exposure of the Dagachhu HPP project is much greater than the alternative of increased power generation through existing thermal power plants (Step 1a - Project Alternative 3) in India. Projects undertaken in the Himalayan Mountains are subject to extreme physical challenges that complicate construction, may extend schedules and impact costs. These challenges include:

• ***Access to the project sites*** – The Dagachhu HPP project is located in a region of extreme terrain. While only 40 km from the capital Thimphu (in straight line), land access to the project site involves significant altitude change over marginal roads. Project components and equipment generally arrive via India and must be trucked over high altitude passes. The roads, single lane in many places, are narrow, winding and poorly maintained. They overlook sheer drop-offs and are overhung by landslide-prone cliffs. This type of access makes transporting heavy equipment and oversized components dangerous and risky, and subject to loss or delay. In addition, the remoteness of the project site requires the construction of project related access roads to the dam site as well as power house and switch yard, requiring large funds for site development.

• ***Civil engineering challenges*** – The civil engineering component of the project is difficult due to extreme gradients and unstable slopes. Currently, there is no road access to the main project sites (dam, power house and switchyard). Water from the Dagachhu is diverted by a small dam at an altitude of app. 825 m (above sea level) through a short tunnel into the de-silting basin. From there, the water will flow through the main tunnel (app. 7,700 m) and through the steel penstock (app. 360 m) into the power house. This high-head characteristic allows the project to extract significant amounts of energy from a relatively small flow of water. This greatly complicates the construction work, creates greater risk exposure, and increases its capital cost.

• ***Schedule*** – The development and implementation schedule for a complex project like the Dagachhu HPP project imposes barriers not faced by alternative generation projects. The timeline for the project is significantly greater than for alternative projects (e.g. thermal or wind power plants – Step1a Alternatives 1 and 2) due to the nature of hydropower projects in general and because of additional road and infrastructure construction requirements for Dagachhu HPP in particular. An extended schedule creates increased exposure to adverse conditions, increases exposure to construction risk, and generally elevates financing and development costs. At the same time, the longer timeline exposes a project to greater potential for contingent impacts like legislative and regulatory change, which can alter project fundamentals.

• ***Hydrology*** – The Dagachhu HPP project faces risk from variations in precipitation and associated water flow in the watershed. Being a run-of-river hydro project the project does not have any water impoundment and is therefore dependent upon in-stream flow rates for its ability to generate power. Another reason is the small catchment area for Dagachhu (687km2). An additional hydrology-associated risk faced by the project was a lack of suitable data on the hydrology of the watershed, which added uncertainty to project design and performance projections.

Based on the 515 GWh of electricity generation from 126 MW capacity, the PLF of project comes out to be 46.66%. This figure is low in comparison with other Bhutanese hydro power plants with a similar size (see table below).

Table 6Plant Load factor for selected Bhutanese hydro power plants

Project	**Installed Capacity (MW)**	**Generation 2006/07 (GWh)**	**Plant Load Factor**
Basochhu	64	314	56%
Chhukha	336	1830	62%
Kurichhu	60	374	71%

• ***Transmission*** – The Dagachhu HPP Project is located at a considerable distance from the 220kV power grid. Power generated by the project is delivered over a 220 kV radial transmission line to a substation at Tsirang, some 18 km away from the project site. Radial transmission lines are by definition single points of interconnection and impose added risk. In case of failure, there is no alternative power delivery path or contingency available. The radial line serving the Dagachhu HPP project traverses the same rugged terrain described above. It is exposed to outages related to tree contacts, landslides, and frequent lightning strikes.

• ***PPA related risk*** – Risks associated with the legal and regulatory structure of the Power Purchase Agreement (PPA) with India contribute significantly to overall project risk. The Dagachhu HPP project has a higher degree of exposure to PPA related risk than alternative renewable energy or thermal based power plants projects in India (Step1a – Project Alternatives 1 and 2), which can sell the energy locally. Because of the need to conclude a PPA for power export to the Eastern regional grid of India, the project proponent is required to deal with a very limited number of Indian companies which are licensed to handle power import and export. This does not allow many negotiating alternative agreements and therefore limits the bargaining power of the project proponent and exposes the project to all types of performance risks of a few counterparts.

• ***Non-Recourse risk*** – In developing countries, it is common for project lenders to establish a security interest in the Project's assets. Typically the security interest gives the lenders the ability to foreclose on the security and remove project assets in the event of a default on the project loan.
This is a viable option for lenders in situations where capacity increments are satisfied by thermal or wind generation units (e.g. Alternatives 1 and 2 of Step1a) because combustion turbines or reciprocating engines are relatively easy to relocate. In the case of the Dagachhu HPP project, this is not an option as the project assets are specifically made for the project and are immovable; therefore the assets have very little salvage value. In the event of a default, lender recourse is limited to either operate or not operate the project, or sell it as a distressed asset.

The risks identified above have imposed barriers on the viability of the project that, absent its registration as a CDM activity, will seriously threaten its long-term economic well-being (see Step 2 Investment Analysis). At the same time, alternative power generation projects in India – namely natural gas fired combustion turbine or wind or biomass projects – do not face the same degree of exposure or have the same level of impact. (This contention will be further delineated in Sub-Step 3b.)

Direct impacts resulting from the barriers associated with these risks were readily apparent in the investigation of financing options available to the project. Commercial lenders, although aware of country and project specific risk, nonetheless showed real interest in the project but required further detailed investigations before any detailed terms could be given. However, initial indicative responses from potential lenders provided clear evidence that registration of this project under the CDM would be a substantial benefit in the project assessment and would have a positive influence on the lending terms (see Enclosure 3: OeKB Indicative Letter for Export Credit).

Therefore, the CDM option was seriously taken into account from the very beginning of the project development. The CDM consulting services were contracted at the same day as the development of the feasibility study (March 2005) which is significantly earlier than the start date of the project activity (July 2006).

Technological barriers and barriers due to prevailing practice are not applicable to the Dagachhu HPP project.

Sub-step 3 b - Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed project activity):

2. As referenced above, risk-related factors impose distinct barriers to development of the Dagachhu HPP project. Sub-step 3a elaborates the effects of specific risks on the project. In this section, we will show that the barriers identified in Sub-step 3a would not prevent the implementation of alternative projects identified in Sub-step 1a, i.e. the generation of equal amount of energy through thermal power generation (Alternative 1) or renewable power generation (Alternative 2) in India. A natural gas fired project alternative is chosen for comparison as coal fired plants in India are of larger ratings (typically 250 MW, 500 MW or higher). The comparison with a renewable alternative is done with a hydro power plant in the Eastern Indian grid (e.g. most recently built hydro power plant Rangit-III with 60MW built in 2000). It is difficult to compare HPP Dagachhu with other Bhutanese hydro power plants[13] as they have been directly/ indirectly financed by the Government of India. While some of the same barriers generally exist for alternative generation projects, their influence on those projects is greatly reduced and is in several cases non-existent.

An item by item examination of the barriers identified in Sub-step 3a reveals the following:

• ***Country risk*** – Power plant projects in India do have a much more favourable risk structure because of the international standing of India in the international financing market. Furthermore, if the power is generated and sold in India, the project developer is not exposed to any currency exchange risk as the majority of cash flows are in a single currency (Indian Rupees).

Therefore, all of the project alternatives (i.e. natural gas fired power plant or renewable energy power plant implemented in the Eastern Indian region) are affected less strongly by the country risk than the proposed project activity.

[13] More details about the Bhutanese hydro power plants is provided in step 4. Common Practice Analysis.

• ***Access to project financing*** – Project developers in India do have much easier access to project financing due to the availability of Indian financing institutions for project financing as well as potential equity investors. Therefore, access to financing sources does not pose a barrier to developers of thermal and or renewable energy power plants in India.

• ***Allowed return on equity*** – The required return on equity (10% post tax) for the project activity has been established by the Bhutan Electricity Authority[14].For new Indian power plants, the Indian Central Electricity Regulatory Commission (CERC) has set up an acceptable range between 14% and 16% for returns on equity after tax which is significantly higher than the 10% allowed for Dagachhu HPP.[15]

• ***Project site access*** – Most natural gas fired combustion turbine projects are sited where major natural gas pipelines and high voltage transmission lines are in close proximity. These proximities often occur in areas that have existing infrastructure and roads. In India, possible sites would be around industrial zones in relatively uniform terrain. Site access in these zones is relatively easy, roads are good, and associated risks are greatly reduced.
Considering the underdeveloped infrastructure in Bhutan, any renewable energy project in India can be expected to have better and easier access to the project site as well. This is due to a developed road network at generally lower altitudes, reducing the risk of impassability due to weather conditions.

• ***Civil engineering challenges*** – Alternative thermal and/or renewable energy projects in India not only enjoy easier site access but typically present few challenges with regard to site topography and conformation. Civil works are largely a matter of clearing and grading. Any site that would require substantial civil alteration would quickly be eliminated as an option for development.
Although there may be thermal and/or renewable energy projects in India with similar engineering challenges to be overcome (Step1a – Alternative 1 or 2), due to India's large size many alternative locations and/or project types are available for project developers in India.

• ***Schedule*** – The time required developing and constructing thermal power plants or wind turbines is significantly less than that required to develop and construct the Dagachhu HPP project. A typical simple cycle combustion turbine peaking plant can be constructed in a matter of app. 2 years, as opposed to 4 to 5 years for the run-of-river hydro project Dagachhu. Consequently, the risk exposure associated with time is dramatically reduced.
Even hydro projects in India would require shorter construction periods due to easier project site access and less complicated engineering solutions as described above.

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[14] Source: Bhutan Electricity Authority -Tariff Determination Regulations, 2006

[15]Various publicly available documents explicitly state this CERC benchmark for power generation projects for determination of tariffs available at the start date of the Project. CERC's discussion paper of June 2003 stated that the preferred approach for the benchmark for conventional power generation would be cost of equity approach and indicated a 16% post tax return on equity benchmark. (http://www.cercind.gov.in/Terms_ Condition_of_Tariff.pdf). CERC's notification (March 2004) revised the benchmark for conventional power generating companies to 14% post tax return on equity. (http://cercind.gov.in/13042007/Terms_and_ conditions_ of_tariff.pdf). These regulations shall come into force on 1.4.2004, and unless reviewed earlier or extended by the Commission, shall remain in force for a period of 5 years (31.3.2009). The benchmark of 14% or 16% has been used in the most recently published CERC orders for Indian hydro power plants, e.g.: http://www.cercind.gov.in/07012008/Pet-No-76-07.pdf (RoE 14%)

• ***Fuel risk (Hydrology)*** – In the case of a hydro project, the fuel risk is characterized as hydrology risk – the amount of water available for power generation at any particular time. For gas-fired projects, the equivalent risk would be fuel supply risk. This risk can be defined by whether or not natural gas is available when the plant is dispatched. In the case of hydrology, the variables are largely outside the control or influence of the plant operator. There is no way to control precipitation, particularly for run-of-river power plants without storage capability such as Dagachhu HPP. For a thermal project utilizing natural gas or biomass, the fuel supply risks are much more manageable. If there is a disruption in supply, it can be identified and addressed very directly. Disruptions are normally of short duration. Should a disruption be longer term, arrangements for an alternative supply can normally be made.
Nevertheless, hydro or wind projects alternatively constructed (Step 1a – Alternative 2) in India would have a similar risk profile than the Dagachhu HPP in terms of hydrology or wind profile. But again, due to its large size many alternative locations are available for project developers in India which can be chosen based on optimal water or wind conditions.

• ***Transmission*** - Unlike a run-of-river hydro project, thermal power plants enjoy considerable flexibility for choosing an optimal project site. Furthermore, India offers a much more developed grid infrastructure throughout the country. One of the primary criteria used in site selection is access to suitable transmission, with good routing alternatives. It would be rare and generally unnecessary for any of the alternative project to face a radial line outage risk of the type dictated by the location of the Dagachhu HPP project.

• ***PPA related risk*** – The PPA risk identified for the Dagachhu HPP project is related to the fact that it requires bilateral arrangements between Bhutan and India and that negotiations must be held with a single company licensed for power delivery between Bhutan and the Eastern regional grid of India. For any alternative power project in India both risks identified do not exist because the energy can be sold domestically to a number of energy utilities, thereby increasing negotiating power.

• ***Non-recourse risk*** – Thermal (fossil or biomass) or wind power projects provide lenders with tangible assets that can be pledged as security and seized and relocated in the event of a default. The combustion/steam/wind turbines represent a major project asset and are relatively easy to relocate. This provides lenders with a recourse option unavailable to those who would fund a hydro project, and lowers the overall project risk profile accordingly. Therefore, also alternative hydro projects in India and Bhutan would be affected by this risk.

As the risk comparison above demonstrates, the effects of the various risk-related barriers identified for the Dagachhu HPP project have less of an adverse impact on the alternative plants in most of the cases. To our knowledge, none of the project alternatives in India has been nor should be prevented from implementation due to the barriers identified in this review. On the other hand, all of the identified risks have the potential to significantly impact the Dagachhu HPP project.

The results of conducting the Step 3 - Barrier Analysis clearly demonstrate that the Dagachhu HPP project has been and continues to be subject to barriers that have a material influence in the financing and overall development, construction and operation of the Project. The project owner further believes that the project alternatives, i.e. generating the same amount of energy through gas turbine or renewable energy power plants in India is not affected by the same barriers, and that the barriers have not caused an inability for them to be implemented.

3. Provide transparent and documented evidence, and offer conservative interpretations of this documented evidence, as to how it demonstrates the existence and significance of the identified barriers and whether alternatives are prevented by these barriers. Anecdotal evidence can be included, but alone is not sufficient proof of barriers. The type of evidence should at least include one of the following:

- *(a) Relevant legislation, regulatory information or industry norms;*
- *(b) Relevant (sectoral) studies or surveys (e.g. market surveys, technology studies, etc) undertaken by universities, research institutions, industry associations, companies, bilateral/multilateral institutions, etc;*
- *(c) Relevant statistical data from national or international statistics;*
- *(d) Documentation of relevant market data (e.g. market prices, tariffs, rules);*
- *(e) Written documentation of independent expert judgments from industry, educational institutions (e.g. universities, technical schools, training centres), industry associations and others.*

Ad (b): Relevant (sectoral) studies or surveys
The financial sector of Bhutan was assessed in detail by the World bank in 2002[16]. The chapter about "Financial Sector Issues" explains in detail some of the barriers to investment in Bhutan, such as high borrowing costs, poor access to credit and lack of innovative financial instruments.

Ad (c): Relevant statistical data
As shown in the external debt statistics of Bhutan (see Table 5), commercial debt only plays a minor role (less than 4% of the total convertible currency debt outstanding) in financing projects in Bhutan. Furthermore, the major global rating agencies have not provided credit ratings for Bhutan (see for example www.standardandpoors.com).
This provides supporting evidence that barriers to commercial debt financing do exist in Bhutan.

Ad (d): Relevant market data
It was shown in Sub-step 2b that currently the maximum achievable tariff for energy export from Bhutan to India is 2.35 INR/kWh in 2012. As indicated in Sub-step 1a, the proposed project activity has to compete against several project alternatives in the regional grid of Bhutan and Eastern region of India.

Additionally to the sources mentioned above, a detailed Feasibility Study of the Dagachhu Hydropower project was prepared in order to assess the geological, hydrological, environmental and technical feasibility of the project. The project risks identified in this Sub-step are described in detail in the Feasibility Study.

→ ***If both Sub-steps 3a – 3b are satisfied, proceed to Step 4 (Common practice analysis)***
Sub-steps 3a and 3b are satisfied.

Step 4 - Common Practice Analysis

Sub-step 4a - Analyze other activities similar to the proposed project activity:
1. The Dagachhu HPP project utilizes proven technology to generate electricity from surface water hydrologic resources in Bhutan. Other hydropower projects have also been constructed in Bhutan, utilizing similar technology. Therefore it is appropriate to assess whether the project activity represents common practice in the area.

[16] Pilot Investment Climate Assessment – Bhutan (see http://www.ifc.org/ifcext/economics.nsf/AttachmentsByTitle/IC-Bhutan.pdf/$FILE/IC-Bhutan.pdf)

Substep 4b - Discuss any similar options that are occurring:
2. & 3. During the last 10 years, four medium and large hydroelectric projects were implemented in Bhutan besides other small hydro power plants:

Kurichu Hydroelectric Project
This project has an installed capacity of 60 MW and an annual generation of 400 GWh. Generation from three units (out of four) started from October 2001 and it has started supplying power to six Dzongkhags in eastern Bhutan and two Dzongkhags in south-central Bhutan. Surplus power is being exported to India through the 132 kV Gelephu-Salakati line. The project is financed by a combination of bilateral assistance and soft loan from the Government of India.

Basochu Upper Stage Hydropower Project
This project has an installed capacity of 22.2 MW with an annual generation of 105 GWh. The project has been completed in December 2001. This project has helped to augment the generation supply in Western Bhutan as well as improve the reliability of power supply in the region. The project is financed by the Austrian Government under a financing mix of bilateral assistance and soft loan.

Basochu Lower Stage (Rurichu) Hydropower Project
The lower stage of the Basochu project has an installed capacity of 40 MW with an annual energy generation of 186 GWh, and was completed in December 2004. The project is financed under Official Austrian Export Promotion Scheme Loan.

All of the above mentioned projects are located in areas in which rather good infrastructure, such as road access and proximity to high voltage grid was already available. As a result, the socio-economic and development indicators in these areas were also above average in Bhutan.
In contrast, the Dagana district, where proposed project activity is planned to be implemented, is characterized by household income levels below national average and a low rate of electrification (12%). Implementing the project in this area would have several positive impacts such as:

- Electrification of rural households through investments in the low-voltage power distribution grid in the project area and associated multiple benefits like education of children, improved health, additional income generation etc.
- Infrastructure development like roads, bridges, schools, health clinics etc.
- Improvement of living standards of the people living in and around the project due to availability of employment opportunity, skill development, easier market access etc.
- Development of small scale industries in the area

While the remoteness of the project area increases the socio-economic significance of the project, the costs of project development and implementation are much higher compared to more developed regions.

Table 7 Cost per MW for Dagachhu HPP as compared to other HPPs in Bhutan

Project	**Installed Capacity (MW)**	**Total Cost (Million Nu.)**	**Cost per MW (Million Nu.)**	**Year of Commissioning**
Basochu	64	3261	**50.95**	2002 & 2005
Chhukha	336	2460	**07.32**	1986
Kurichhu	60	5640	**94.00***	2001
Dagachhu	126	11600	**92.06**	-

* Cost per MW for Kurichhu was high since it is a low head project with powerhouse at the toe of the dam, and was constructed more for socio – economic considerations.

Due to the fact that further hydropower construction concentrates on rather developed valleys in Bhutan, the development of medium-size hydropower plants in remote project areas is not common practice.

Furthermore, due to the lack of financial resources within Bhutan, the implementation of the recent hydropower projects required substantial amounts of donor financing, soft loans or other development funds. The use of donor funding for the development of its hydropower resources has several disadvantages for Bhutan:

- Financial aid which might be needed more urgently in other sectors is being tied up.
- As Bhutan progresses in its development, attracting donor funding for large scale infrastructure projects becomes increasingly difficult. While the Basochu projects were funded through grants, ERP credit lines and soft-loan components, these bilateral financing mechanisms are not available anymore to fund any further hydropower projects in Bhutan.
- Donor funded project development limits Bhutan's ability to steer the project development process and the operation of the power plant independent of the desires of the donor country.

In order to mitigate above mentioned disadvantages, Bhutan is aiming at developing any further medium-size hydropower projects utilizing commercial term financing. Thereby, Bhutan keeps its full sovereignty over the development and implementation of the project. Furthermore, this allows Bhutan to have full flexibility regarding the utilization of the energy generated during the operational phase. This is a unique approach which is completely different from the development and implementation of medium-size hydro power plants in Bhutan so far.

→ If sub-steps 4a and 4b are satisfied, i.e. similar activities cannot be observed or similar activities are observed, but essential distinctions between the project activity and similar activities can reasonably be explained, then the proposed project activity is additional.

Sub-steps 4a and 4b are satisfied. Therefore, the Dagachhu HPP project activity does not represent common practice and is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

The chosen methodology is ACM0002, Version 07 (EB36), Sectoral scope:1 which refers to the "Tool to calculate the emission factor for an electricity system" (Version 01). The chosen methodology describes a

stepwise approach. Baseline emission factor is calculated as combined margin, consisting of a combination of operating margin (OM) and build margin (BM) factors.

There are 4 options mentioned in the "Tool to calculate the emission factor for an electricity system" (Version 01) for calculating the operating margin emission factor:
(a) Simple OM; or
(b) Simple adjusted OM, or
(c) Dispatch Data Analysis OM, or
(d) Average OM.

Option (a) Simple OM method has been selected. According to the methodology the simple operating margin is used where there is not enough data to use dispatch data analysis to calculate the operating margin and low-cost/must run resources constitute less than 50% of total grid generation. According to the *CO_2 Baseline Database for the Indian Power Sector* (User Guide version 3.0, dated December 2007) hydro and nuclear qualify as low-cost/must-run sources. In the regional grid including Eastern Indian grid and Bhutanese power plants in 2006/2007 low-cost/must-run sources covered 13.2% of the total grid generation.

Build margin is calculated on the basis of 'Option 1' as defined in ACM0002. As per Option 1, the two sample groups (either most recent information available of the five power plants built most recently at the time of the PDD submission or power plant capacity additions in the electricity system that comprise 20% of system generation in GWh and that have been built most recently) are compared to determine which sample group comprises the larger annual generation.

The baseline emission factor is calculated as the weighted average of the Operating Margin emission factor ($EF_{OM,y}$) and the Build Margin emission factor ($EF_{BM,y}$).

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

There are no fixed ex-ante parameters.

For the estimation of the emission reductions during the validation due to the project activity, the following figures have been used:

1. In the registered PDD, the estimated annual electricity generation in 2012 is 500 GWh which is then reduced by 0.2% per year due to technical capacity degradation. In the updated PDD, this value is increased to 515 GWh(+3%) based on the simulation results for the increased installed capacity.

2. Estimated Combined Margin (CM) emission factor
The CM is estimated to be 1.004 tCO_2/MWh, calculated as 50%:50% weight of the Operating Margin (OM=1.16 tCO_2/MWh) and the Build Margin (BM=0.85tCO_2/MWh). The relevant data for this calculation was taken from the CEA database version 03 and the Bhutan annual Power Data book 2006/07. During verification, the baseline CM will be calculated based on the latest versions from these sources available.

B.6.3 Ex-ante calculation of emission reductions:

The baseline emission factor (EF_y) for the regional grid including Eastern Indian grid and power grid in Bhutan is calculated as a combined margin (CM) consisting of the combination of operating margin (OM) and build margin (BM) factors according to the following three steps.

Step 1. Calculation of the Operating Margin emission factor ($EF_{OM,y}$)

Option (a) Simple OM method has been selected.

Additionally, the "Tool to calculate the emission factor for an electricity system" (Version 01)gives 4 options for the Operating Margin (OM) emission factor calculation to determine the CO_2 emission factor for net electricity imports ($COEF_{i,j,imports}$) from a connected electricity system within the same host country(ies):

a) 0 tCO_2/MWh, or
b) the weigthed average operating margin (OM) emission rate of the exporting grid, or
c) the simple operating margin emission rate of the exporting grid in case the low-cost/must-run resources constitute less than 50% of total grid generation, or
d) the simple adjusted operating margin emission rate of the exporting grid.

For this project the option a) is chosen as this figure is calculated and given in the CO_2 Database for the Indian Power Sector (User Guide Version 3.0 dated December 2007). Only in 2005/2006 net imports to the regional grid consisting of Bhutan and the Eastern Indian grid were reported. The 818 GWh from the North-Eastern region represented around 1 % of the total generation in the regional grid.

According to "Tool to calculate the emission factor for an electricity system" (Version 01) the simple OM can be calculated using either of the following data vintages for years(s) y:

- Ex-ante option: A 3-year generation-weighted average, based on the most recent data available at the time of submission of the CDM-PDD to the DOE for validation, without requirement to monitor and recalculate the emission factor during the crediting period, or,
- Ex post option: The year in which the project activity displaces grid electricity, requiring the emission factor to be updated annually during monitoring.

The *ex-post* option is chosen. This means that actual emission reductions will be claimed during the verification time based on the calculated value of CM by ex post monitoring of latest OM & BM values (CEA database & Bhutan annual Power Data book latest data available at the time of verification).

For the estimation of the emission reductions, the CEA database version 03 & Bhutan annual Power Data book 2006/07 were used. The Simple Operating Margin (OM) emission factor ($EM_{OM,simple,y}$) is estimated as the generation-weighted average emissions per electricity unit (tCO_2/MWh) for three years historic production data 2004/2005, 2005/2006and 2006/07 of all generating sources serving the system not including low-operating cost and must-run power plants:

$$EF_{OM,y} = \frac{\sum_{i,j} F_{i,j,y} COEF_{i,j}}{\sum_{j} GEN_{j,y}}$$

Where $F_{i,j,y}$ is the amount of fuel i (in a mass or volume unit) consumed by relevant power sources j in year(s) y, j refers to the power sources delivering electricity to the grid, not including low-operating and must-run power plants, and including imports to the grid, $COEF_{i,j,y}$ is the CO_2 emission coefficient of fuel I (tCO_2/ mass or volume unit of the fuel), taking into account the carbon content of the fuels used by relevant fuel sources j and the percent oxidation of the fuel in year(s) y, and $GEN_{j,y}$ is the electricity (MWh) delivered to the grid by source *j*.

The CO_2 emission coefficient $COEF_i$ is obtained as

$$COEF_i = NCV_i * EF_{CO2,i} * OXID_i$$

where:
NCV_i is the net calorific value (energy content) per mass or volume unit of a fuel i, $OXID_i$ is the oxidation factor of the fuel, $EF_{CO2,i}$ is the CO_2 emission factor per unit of energy of the fuel i.

The data for the calculations is obtained from CO_2 baseline database for the Indian Power Sector (User Guide Version 3.0, dated December 2007)[17] which was designed especially for this purpose. The data of the Bhutanese power production was obtained from Annual Power Data Book[18].The data of the power plantsincluded in the regional grid and considered in the calculations are given in Annex 3.

Step 2. Calculation of the Build Margin emission factor ($EF_{BM,y}$)

The Build Margin (BM) is calculated on the basis of 'Option 1' as defined in ACM0002. As per Option 1, the two sample groups (either most recent information available of the five power plants built most recently at the time of the PDD submission or power plant capacity additions in the electricity system that comprise 20% of system generation in GWh and that have been built most recently) are compared to determine which sample group comprises the larger annual generation.

The first sample group (five most recently built power plants in the regional grid)is listed in

[17] Source: http://www.cea.nic.in/planning/c%20and%20e/user_guide_ver3.pdf

[18] Annual power data book 2006/07 for Bhutan (Source: Ministry of Economic Affairs, Bhutan)

Table 8. As this group includes two plants which were put in operation the last day of the period 2006/07 (31.03.2007) with zero generation, this sample group comprises of seven power plants with a generation of 6,359GWh in 2006/07.

Table 8: The 7 most recently built power plants (2007) in the regional grid (Eastern Indian grid and Bhutan)

Name of Power Plant	Installed Capacity (MW)	Gross Generation2006/07 (GWh)
KAHALGAON	500	0
MEJIA	210	0
TALA	1020	1,980
JOJOBERA IMP.	120	363
TALCHER STPS	500	2,480
MEJIA	210	1,435
BASOCHU-II (WANGDUE)	20	102
Total	**2,580**	**6,359**

The second sample group, the most recently built power plant capacity additions that comprise 20% of net power generation in the regional grid (including the Eastern Indian grid and power grid in Bhutan) in 20006/07, comprises an annual generation of 19,701GWh. (See Annex 3 for detailed plant data).

Thus, the second sample group clearly comprises the larger annual generation and is used to calculate the Build Margin emission factor ($EF_{BM,y}$).

The Build Margin Emission factor ($EF_{BM,y}$) as the generation-weighted average emission factor (tCO_2/MWh) of a sample of power plants m is calculated as follows:

$$EF_{BM,y} = \frac{\sum_{i,m} F_{i,m,y} COEF_{i,m}}{\sum_{m} GEN_{m,y}}$$

where$F_{i,m,y}$, $COEF_{i,m}$and $GEN_{m,y}$are analogous to the variables described for the simple OM calculation above for plants m.

Step 3. Calculate the baseline emission factor EF_y

The baseline emission factor is calculated as Combined Margin (CM) consisting of the combination of the Operating Margin emission factor ($EF_{OM,y}$) and the Build Margin emission factor ($EF_{BM,y}$) by using the following formula defined in ACM0002.

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

where the weights $W_{OM}$and W_{BM}, by default, are 50% (i.e., $W_{OM}= W_{BM}= 0.5$) as mentioned in ACM0002, and $EF_{OM,y}$ and $EF_{BM,y}$ are calculated as described in Steps 1 and 2 above and are expressed in tCO_2/MWh. The baseline emission factor, thus, comes out to be **1.004tCO_2/MWh**.

Leakage

The main emissions potentially giving rise to leakage in the context of electric sector projects are emissions arising due to activities during the hydro power plant construction and operation. However, as per the methodology ACM0002 used for the preparation of this baseline, these do not need to be considered as leakage. Hence, there is no leakage in this project.

Table 9 Results from calculations of the baseline emission factor EF_y

Parameters	2004/2005	2005/2006	2006/2007
Total net generation in the regional grid (including imports) (GWh)	80,304	89,461	98,316
Absolute emissions in the regional grid, ($ktCO_2$)	83,957	92,518	96,360
Generation in the Operating Margin (GWh)	69,746	80,681	85,375
Absolute emissions in Operating Margin (OM) ($ktCO_2$)	83,957	92,518	96,360
20% of net generation in the regional grid (GWh)			19,663
Absolute emissions in Build Margin (BM) ($ktCO_2$)			16,761
Annual Simple Operating Margin (OM) (tCO_2/MWh)	1.20	1.15	1.13
Average Simple Operating Margin (OM) (tCO_2/MWh)	1.16		
Build Margin (BM) (tCO_2/MWh)			0.85
Baseline Emission Factor (EFy) (tCO_2/MWh)	1.004		

Calculation of emission reductions

The project activity reduces carbon dioxide (CO_2) through substitution of grid electricity generation (which includes fossil fuel fired power plants) by renewable electricity. The emission reduction (ER_y) by the project activity during a given year y is the difference between baseline emissions (BE_y), project emissions (PE_y) and emissions due to leakage (L_y), as follows:

$ER_y = BE_y - PE_y - L_y$

Where,
$PE_y = 0$ (no project emissions from a hydro power plant as per ACM0002)[19]
$L_y = 0$ (no leakage as per ACM0002)

Thus,
$ER_y = BE_y$

Furthermore,
$BE_y = EG_y * EF_y$

Where,
EF_y= baseline emission factor = $EF_{grid,CM,y}$
EG_y= net electricity generated at Dagachhu HPP and delivered to the regional grid (MWh)

[19] The "Power Density" (W/m²) of the project is 3,600 W/m² (126,000,000 W / 35,000 m2) which is by far above the threshold of 10 W/m². Therefore, project emissions from the reservoir may be neglected (PEy=0) as per ACM0002.

Therefore,

$ER_y\ (tCO_2) = BE_y(tCO_2) = 1.004\ tCO_2/MWh * EG_y$

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

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_2 e)
2014	0	387,766	0	387,766
2015	0	515,987	0	515,987
2016	0	514,955	0	514,955
2017	0	513,925	0	513,925
2018	0	512,897	0	512,897
2019	0	511,872	0	511,872
2020	0	510,848	0	510,848
2021	0	127,457	0	127,457
Total (tonnes of CO_2 e)		3,595,706		3,595,706

The crediting period start on 01/04/2014 and will end on 31/03/2021.

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

The applied monitoring methodology is approved consolidated baseline and monitoring methodology ACM0002/Version 07 (EB36) Sector Scope:1.

The monitoring methodology lists the parameters that need to be monitored for estimating the baseline and project emissions as well as leakage. The chosen monitoring methodology is applicable for grid-connected electricity capacity additions from run-of-river hydro power plants as well as for projects where the geographic and system boundaries for the project activity can be clearly identified and information on the characteristics of the grid is available. These conditions are met in the Dagachhu HPP project.

B.7.1 Data and parameters monitored:	
Data / Parameter:	EG_y
Data unit:	MWh
Description:	Net annual electricity generated at Dagachhu HPP and supplied to the grid
Source of data to be used:	Measured and recorded at Dagachhu HPP
Value of data applied for the purpose of calculating expected emission reductions in section B.5	515,000
Description of measurement methods and procedures to be applied:	Electricity measured is used in the calculation of emission reductions. The electricity generated in Dagachhu HPP is measured hourly and recorded monthly.
QA/QC procedures to be applied:	The electricity meters at Dagachhu HPP will undergo maintenance/calibration subject to appropriate industry standards. The Indian counterpart (agency receiving the power) will also verify the power received for billing purposes (as defined by the Power Purchase Agreement) and therefore it can be cross checked with BPC`s wheeling charge invoice and the invoice raised by Tata Power Trading Company Ltd..
Any comment:	The technical feasibility study estimated 500,000 MWh based on 114MW installed hydro power capacity and hydrological data from the Dagachhu river; the updated value of 515,000 MWh is based on the final installed capacity of 126 MW and technology provider confirmation .

Data/Parameter:	Cap_{PJ}
Data unit:	W
Description:	Installed capacity of the hydro power plant after the implementation of the projectactivity.
Source of data:	Project site.
Measurement procedures (if any):	Determine the installed capacity based on recognized standards.
Monitoring frequency:	Yearly
QA/QC procedures:	
Any comment:	-

Data/ Parameter:	A_{PJ}
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 ofdata:	Project site.
Measurement procedures (ifany):	Measured from topographical surveys, maps, satellite pictures, etc.
Monitoring frequency:	Yearly
QA/QC procedures:	-
Anycomment:	-

Data / Parameter:	$EF_{grid,CM,y}$
Data unit:	tCO_2/MWh
Description:	CO_2combined emission factor of the regional power grid
Source of data used:	Own regional baseline database including Eastern Indian power grid and power grid in Bhutan (data taken from CEA database & Bhutan annual Power Data)
Measurement procedures (ifany):	Calculated based on 50%: 50% weight of EF_{OMy}&EF_{BMy}
Monitoring frequency:	Yearly
QA/QC procedures:	-
Anycomment:	-

Data / Parameter:	$EF_{grid,OMy}$
Data unit:	tCO_2/MWh
Description:	CO_2 operating margin emission factor of the grid
Source of data used:	Own regional baseline database including Eastern Indian power grid and power grid in Bhutan (data taken from CEA database & Bhutan annual Power Data)
Measurement procedures (ifany):	Ex-post Monitoring of CEA database & Bhutan annual Power Data book (latest data available at the time of verification)
Monitoring frequency:	Yearly
QA/QC procedures:	-
Anycomment:	-

Data / Parameter:	$EF_{grid,BMy}$
Data unit:	tCO_2/MWh
Description:	CO_2 Build margin emission factor of the grid
Source of data used:	Own regional baseline database including Eastern Indian power grid and power grid in Bhutan
Measurement procedures (ifany):	Ex-post Monitoring of CEA database & Bhutan annual Power Data book (latest data available at the time of verification)
Monitoring frequency:	Yearly
QA/QC procedures:	-
Anycomment:	-

Data / Parameter:	$COEF_i$
Data unit:	tCO_2/mass or volume unit
Description:	CO_2 emission coefficient of each fuel type i
Source of data used:	CEA database
Measurement procedures (ifany):	Ex-post Monitoring of CEA database (latest data available at the time of verification)
Monitoring frequency:	Yearly
QA/QC procedures:	-
Anycomment:	-

The Environmental Assessment foresees an Environmental Management Plan (EMP) including a Catchment Treatment Plan. The implementation of these plans will be checked during the CDM verification.

The Resettlement Action Plan (RAP) set rules for the compensation of affected people, e.g. land substitution. The correct implementation of those activities will be checked during the CDM verification.

B.7.2 Description of the monitoring plan:

By establishing a clear, precise and well-defined monitoring procedure for the Dagachhu Hydro Power Project, the accurate calculation of emission reductions is ensured. The Dagachhu HPP project will employ latest state-of-the-art monitoring and control equipment, which will also measure net power generated (i.e. power supplied to the grid). All equipment will be maintained and calibrated at regular intervals. The monitoring procedure which will be used in this project to enable the correct calculation of generated emission reductions is depicted in Annex 4.

During implementation of the Dagachhu HPP and before the start of the project activity (i.e. during year 2011), the monitoring procedure shown in Annex 4 will be further elaborated by Dagachhu Hydro Power Corporation (DHPC), giving detailed accounts for all of the following:

1. Person at DHPC, responsible for
   - Project management
   - Data collection
   - Preparation of monitoring report
   - Communication with Designated Operational Entity and CDM Executive Board

2. Person at the Project Authority, responsible for
   - Data recording
   - Data collection
   - Calibration of monitoring equipment
   - Maintenance of monitoring equipment and installations

3. Procedures for calibration and maintenance of the monitoring equipment

4. Detailed procedures for monitoring, measurements and reporting (including records handling, storage area of records and performance documentation)

5. Detailed procedures for internal review of reported results/data (including a system for corrective actions)

6. Procedures for training of the monitoring personnel

Installation of monitoring equipment, monitoring procedures, calibration frequency and accuracy class of the monitoring equipment will follow the national standard.

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)

Date of completion: 31/07/2008
Name of entity determining the baseline: Pöyry Energy GmbH, Austria
Contact person: Mr. Christian Steinreiber, Ms.Elvira Lutter
Pöyry Energy GmbH
Laaer-Berg-Strasse 43
1100 Vienna, Austria
Phone: +43 (0)50313 54896
Email: Christian.Steinreiber@poyry.com

These entity mentioned above is not a project participants.

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:

31/07/2006 – start of project activity
Based on the results of the feasibility study, EA and CDM assessment, the Bhutanese government approved the project in 31 July 2006 to take up Dagachhu hydropower project under the condition of CDM development. This can be considered as the first investment decision.

01/01/2008 – start of construction of first infrastructure (road) to the hydropower plant
27/07/2009 – Signed contract for Electrical and Mechanical equipments of the hydro power plant

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

30 years

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

C.2.1. Renewable crediting period

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

01/04/2014

C.2.1.2. Length of the first crediting period:

7 years

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>>

C.2.2.2. Length:

>>

SECTION D. Environmental impacts

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

Under the Environmental Assessment Act 2000 of Bhutan, it is mandatory for hydropower projects to have environmental clearance before proceeding construction. Therefore, a comprehensive **Environmental Assessment (EA)** was prepared by Bhutan Consultants & Research (BHUCORE), an independent environmental & engineering consulting firm located in Thimphu, Bhutan.

Based on the review and approval of the final EIA and Socio-economic assessment report of Dagachhu HPP, the National Environment Commission (NEC) of Bhutan has issued the Environmental Clearances (EC) in June 2007 for development of126MW Dagachhu HPP and also for construction of approach roads (~20 km) and two bridges in the project area.

The following agencies/organizations have issued no objection letter for activities related to development of Dagachhu HPP:

1. Dzongkhag (District) Administration: Dagana Dzongkhag issued no objection letters;
2. Construction of approach roads for project access: Department of Roads, Ministry of Works & Human Settlement issued no objection letter;
3. Project and roads & bridges and 220 kV high voltage transmission line for evacuation of Dagachhu power: Department of Forest, Ministry of Agriculture issued Forestry Clearances.

For further information on the environmental impact of the project, please refer to Enclosure 4: Environmental Assessment – Main Report.

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 of the Dagachhu HPP project are not considered to be significant. Nevertheless, a detailed Environmental Management Plan, which includes relevant mitigation measures, monitoring procedures and responsibilities, is provided in the Environmental Assessment Report (see Enclosure 4).

- Dagachhu Hydropower Project has been selected by the Government of Bhutan as the first large scale CDM project amongst 6 other hydropower options based on social, environmental and economic criteria.
- Topography, hydrological, geological and power optimisation studies have shown that the proposed dam site and tailrace of the Dagachhu Hydropower Project are the most suitable ones. Hence, the project seems feasible from all perspectives.
- It is seen that wind, solar and bio-gas are not proper alternatives to the DHPP.
- The project won’t encroach into any the declared protected areas of Bhutan, nor will it undermine the rich cultural heritage sites of Bhutan.
- There will be some localized impacts due to construction, but they are included in the Environmental Management Plan (EMP).

SECTION E. Stakeholders' comments

A comprehensive public consultation process was carried out as part of the Environmental Assessment. For detailed information on stakeholder comments, please refer to Enclosure 5: Public Consultation Documentation

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

During the public consultation process, meetings were held with district officials (from Dagana Dzongkhag) and with people from the communities that are directly affected by the project. A total of 9 meetings were conducted by the Environmental Assessment team from BHUCORE, in which the Dagachhu Hydropower Project and its potential impacts on the socioeconomic and environmental setting of the region were presented. Furthermore, the purpose of conducting an Environmental Assessment and the public consultation process were explained. The outcome of the feasibility study of the Dagachhu HPP, which includes the access roads and the transmission line, was also presented.

The following Officials from the Dagana Dzongkhag Administration attended the meeting:

1. Goling Tshering, Dasho Dzondag
2. Dorji, District Planning Officer
3. Kaloo Drukpa, Dzongkhag Health Sector Officer
4. Tulsi Ram Sharma, District Medical Officer
5. Phuntsho Tobgay, Dzongkhag Forest Officer,
6. D.B. Chettri, Forest Range Officer

A total of 298 stakeholders from the following communities attended the meetings (a geog is a block within a district):

1. Khebisa gewog
2. Tsendagang gewog
3. Trashiding gewog
4. Goshigewog
5. Kana gewog
6. Drujegang gewog
7. Rangthangling gewog

The comments from all stakeholders were recorded in the Environmental Assessment Report.

E.2. Summary of the comments received:

The Officials welcomed the news of the Dagachhu HPP project development in Dagana and mentioned that it would definitely improve the socioeconomic situation of Dagana as it is one of the remotest Dzongkhags of Bhutan. The Medical Officer warned against of the coming of a large scale hydropower project, because Dagana does not have a full-fledged hospital. The influx of construction workers would create a shortage of human and medical resources in the existing health care system of Dagana Dzonkhag. He also mentioned the danger of the spread of new diseases, malaria, and sexually transmitted diseases due to the arrival of migrant labourers.

In general, the stakeholder comments received from the local population were very positive. The people from the affected communities are very happy about the construction of this project because it will improve the local infrastructure, especially due to the construction of roads, and it will bring electricity to the region. Furthermore, the stakeholders welcome the possibility of other anticipated benefits such as improved social conditions and business opportunities.

Nevertheless, some people expressed concern about whether they would be adequately compensated for their land losses. The compensation in the form of land replacement is the most preferred option. The Land Act 1979, which was revised in 1998, empowers the government to acquire the private land for the general interest of public. The Act also empowers the affected to claim appropriate compensation from the government as per the revised Land Compensation Rates of 1996.

The affected people also provided a No Objection Certificate for the project.

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

As a response to the Medical Officer's comments, the establishment of a permanent dispensary (incl. a doctor, nurse, health assistant and ambulance) as well as measures to combat the spread of malaria and other diseases (such as the purchase of a van for mosquito control spraying) are included in the Environmental Management & Monitoring Plan of the Environmental Assessment Report.

In response to the concerns raised by the local population, the Environmental Assessment Report recommends the preparation of a Resettlement Action Plan (RAP) during the project's detail design stage. Although only one household needs to be resettled due to the construction of the transmission line, the RAP would delineate all affected people and outline appropriate compensation for land losses so that people are not disadvantaged due to the project. The RAP could also outline all possible assistance by the project in the form of employment opportunities, capacity building, etc. so that alternative livelihood is made possible. The mechanism of ensuring proper compensation should also be included in the RAP.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Dagachhu Hydro Power Corporation Limited
Street/P.O.Box:	-
Building:	-
City:	Dagapela
State/Region:	Dagana
Postfix/ZIP:	-
Country:	Bhutan
Telephone:	-
FAX:	-
E-Mail:	-
URL:	-
Represented by:	
Title:	Chief Executive Officer
Salutation:	Mr.
Last Name:	Thinley
Middle Name:	
First Name:	Dorji
Department:	
Mobile:	-
Direct FAX:	+975-6-460830
Direct tel:	+975-17116137
Personal E-Mail:	thinley06@gmail.com

Organization:	Tata Power Trading Company Ltd.
Street/P.O.Box:	SenapatiBapatMarg, Lower Parel, Mumbai
Building:	Tata Power Mahalaxmi Receiving Station
City:	Mumbai
State/Region:	Mumbai
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Country:	India
Telephone:	+91 022 6717 2852
FAX:	Fax: +91 022 6631 0849
E-Mail:	
URL:	http://tatapowertrading.com
Represented by:	
1. Title:	Managing Director
Salutation:	Mr.
Last Name:	Mehra
Middle Name:	
First Name:	Sanjeev
Department:	
Mobile:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	sanjeev.mehra@tatapower.com

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No public funding is foreseen for this project.

Annex 3

BASELINE INFORMATION- Regional grid covering Eastern Indian grid and power grid in Bhutan

NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2005	LOCA-TION	TYPE	FUEL 1	FUEL 2	2004-2005 Net Gen GWh	2004-2005 Abs. Emis. t CO2	2004-2005 in OM	2005-2006 Net Gen GWh	2005-2006 Abs. Emis. t CO2	2005-2006 in OM	2006-2007 Net Gen GWh	2006-2007 Abs. Emis. t CO2	2006-2007 in OM	2006-2007 in BM
PATRATU	**0**		**840**	**ER**	**THERMAL**	**COAL**	**OIL**	**579**	**1,203,019**	**1**	**706**	**1,356,368**	**1**	**526**	**972,941**	**1**	
PATRATU	1	01-Oct-66	50	ER	THERMAL	COAL	OIL										
PATRATU	2	01-Jun-67	50	ER	THERMAL	COAL	OIL										
PATRATU	3	01-Feb-69	50	ER	THERMAL	COAL	OIL										
PATRATU	4	01-Jan-70	50	ER	THERMAL	COAL	OIL										
PATRATU	5	17-Dec-71	100	ER	THERMAL	COAL	OIL										
PATRATU	6	13-Mar-72	100	ER	THERMAL	COAL	OIL										
PATRATU	7	17-Jan-77	110	ER	THERMAL	COAL	OIL										
PATRATU	8	02-Mar-78	110	ER	THERMAL	COAL	OIL										
PATRATU	9	30-Mar-84	110	ER	THERMAL	COAL	OIL										
PATRATU	10	02-Mar-86	110	ER	THERMAL	COAL	OIL										
BARAUNI	**0**		**320**	**ER**	**THERMAL**	**COAL**	**OIL**	**133**	**326,600**	**1**	**96**	**242,342**	**1**	**27**	**62,201**	**1**	
BARAUNI	1	31-Oct-69	50	ER	THERMAL	COAL	OIL										
BARAUNI	2	30-Nov-71	50	ER	THERMAL	COAL	OIL										
BARAUNI	3	01-May-83	110	ER	THERMAL	COAL	OIL										
BARAUNI	4	31-Mar-85	110	ER	THERMAL	COAL	OIL										
KAHALGAON	**0**		**1340**	**ER**	**THERMAL**	**COAL**	**OIL**	**5,867**	**5,694,568**	**1**	**6,020**	**6,090,761**	**1**	**6,031**	**6,072,998**	**1**	
KAHALGAON	1	31-Mar-92	210	ER	THERMAL	COAL	OIL										
KAHALGAON	2	17-Mar-94	210	ER	THERMAL	COAL	OIL										
KAHALGAON	3	24-Mar-95	210	ER	THERMAL	COAL	OIL										
KAHALGAON	4	18-Mar-96	210	ER	THERMAL	COAL	OIL										
KAHALGAON	5	31.Mär.07	500	ER	THERMAL	COAL	OIL							0	0		1
TENUGHAT	**0**		**420**	**ER**	**THERMAL**	**COAL**	**OIL**	**1,092**	**1,295,726**	**1**	**1311**	**2,002,824**	**1**	**2,389**	**3,174,301**	**1**	
TENUGHAT	1	14-Apr-94	210	ER	THERMAL	COAL	OIL										
TENUGHAT	2	10-Oct-96	210	ER	THERMAL	COAL	OIL	0	0								
JOJOBERA IMP.	**0**		**427.5**	**ER**	**THERMAL**	**COAL**	**OIL**	**1,743**	**1,885,744**	**1**	**2126**	**2,307,939**	**1**	**2,443**	**2,664,016**	**1**	
JOJOBERA IMP.	1	22-Dec-95	67.5	ER	THERMAL	COAL	OIL							484			
JOJOBERA IMP.	2	09-Oct-00	120	ER	THERMAL	COAL	OIL	681	715,273		702	736,794		535			
JOJOBERA IMP.	3	27-Aug-01	120	ER	THERMAL	COAL	OIL	663	696,113		702	736,794		749	786,345		
JOJOBERA IMP.	4	23-Sep-2005	120	ER	THERMAL	COAL	OIL				363	381,518		675	708,540		1

NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2005	LOCA-TION	TYPE	FUEL 1	FUEL 2	2004-2005 Net Gen GWh	2004-2005 Abs. Emis. t CO2	2004-2005 in OM	2005-2006 Net Gen GWh	2005-2006 Abs. Emis. t CO2	2005-2006 in OM	2006-2007 Net Gen GWh	2006-2007 Abs. Emis. t CO2	2006-2007 in OM	2006-2007 in BM
CHANDRAPURA	**0**		**780**	**ER**	**THERMAL**	**COAL**	**OIL**	**1,648**	**2,633,923**	**1**	**1775**	**2,538,987**	**1**	**1,876**	**2,563,118**	**1**	
CHANDRAPURA	1	30-Sep-64	140	ER	THERMAL	COAL	OIL										
CHANDRAPURA	2	30-Nov-64	140	ER	THERMAL	COAL	OIL										
CHANDRAPURA	3	30-Jun-68	140	ER	THERMAL	COAL	OIL										
CHANDRAPURA	4	31-Mar-74	120	ER	THERMAL	COAL	OIL										
CHANDRAPURA	5	31-Mar-75	120	ER	THERMAL	COAL	OIL										
CHANDRAPURA	6	29-Mar-79	120	ER	THERMAL	COAL	OIL										
DURGAPUR	**0**		**350**	**ER**	**THERMAL**	**COAL**	**OIL**	**1,291**	**1,969,529**	**1**	**1601**	**2,243,952**	**1**	**1,827**	**2,475,280**	**1**	
DURGAPUR	1	31-May-67	140	ER	THERMAL	COAL	OIL							659			
DURGAPUR	2	05-Dec-81	210	ER	THERMAL	COAL	OIL							1,168			
BOKARO B	**0**		**630**	**ER**	**THERMAL**	**COAL**	**OIL**	**2,201**	**3,725,350**	**1**	**2365**	**3,751,554**	**1**	**2,957**	**4,117,802**	**1**	
BOKARO B	1	24-Mar-86	210	ER	THERMAL	COAL	OIL										
BOKARO B	2	07-Nov-90	210	ER	THERMAL	COAL	OIL										
BOKARO B	3	31-Mar-93	210	ER	THERMAL	COAL	OIL										
MAITHON GT	**0**		**90**	**ER**	**THERMAL**	**NAPT**	**n/a**	**0**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**1**	
MAITHON GT	1	08-Mar-89	30	ER	THERMAL	NAPT	n/a										
MAITHON GT	2	13-Mar-89	30	ER	THERMAL	NAPT	n/a										
MAITHON GT	3	20-Mar-89	30	ER	THERMAL	NAPT	n/a										
MEJIA	**0**		**1050**	**ER**	**THERMAL**	**COAL**	**OIL**	**4,130**	**5,311,316**	**1**	**5262**	**5,741,686**	**1**	**5,610**	**5,986,421**	**1**	
MEJIA	1	21-Dec-95	210	ER	THERMAL	COAL	OIL							1,507			
MEJIA	2	24-Mar-97	210	ER	THERMAL	COAL	OIL	1,140	1,466,347					1,359			
MEJIA	3	25-Mar-98	210	ER	THERMAL	COAL	OIL	1,409	1,811,305					1,421			
MEJIA	4	12-Oct-04	210	ER	THERMAL	COAL	OIL	159	204,787		1435	1,565,349		1,343	1,432,781		1
MEJIA	5	31.Mär.07	210	ER	THERMAL	COAL	OIL							0	0		1
TALCHER	**0**		**470**	**ER**	**THERMAL**	**COAL**	**OIL**	**2,858**	**3,542,605**	**1**	**3174**	**3,899,070**	**1**	**3,189**	**3,909,082**	**1**	
TALCHER	1	01-Jun-95	62.5	ER	THERMAL	COAL	OIL										
TALCHER	2	01-Jun-95	62.5	ER	THERMAL	COAL	OIL										
TALCHER	3	01-Jun-95	62.5	ER	THERMAL	COAL	OIL										
TALCHER	4	01-Jun-95	62.5	ER	THERMAL	COAL	OIL										
TALCHER	5	01-Jun-95	110	ER	THERMAL	COAL	OIL										
TALCHER	6	01-Jun-95	110	ER	THERMAL	COAL	OIL										
I.B.VALLEY	**0**		**420**	**ER**	**THERMAL**	**COAL**	**OIL**	**2,833**	**2,929,295**	**1**	**2773**	**2,844,741**	**1**	**2,976**	**3,047,666**	**1**	
I.B.VALLEY	1	22-May-94	210	ER	THERMAL	COAL	OIL							1,465			
I.B.VALLEY	2	22-Oct-95	210	ER	THERMAL	COAL	OIL							1,511			

NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2005	LOCA-TION	TYPE	FUEL 1	FUEL 2	2004-2005 Net Gen GWh	2004-2005 Abs. Emis. t CO2	2004-2005 in OM	2005-2006 Net Gen GWh	2005-2006 Abs. Emis. t CO2	2005-2006 in OM	2006-2007 Net Gen GWh	2006-2007 Abs. Emis. t CO2	2006-2007 in OM	2006-2007 in BM
TALCHER STPS	**0**		**3000**	**ER**	**THERMAL**	**COAL**	**OIL**	**14,744**	**14,783,118**	**1**	**19703**	**18,809,830**	**1**	**22,356**	**21,238,394**	**1**	
TALCHER STPS	1	19-Feb-95	500	ER	THERMAL	COAL	OIL							3,387			
TALCHER STPS	2	27-Mar-96	500	ER	THERMAL	COAL	OIL							3,580			
TALCHER STPS	3	04-Jan-03	500	ER	THERMAL	COAL	OIL	3,009	3,017,037		3425	3,270,166		4,092	3,887,750		1
TALCHER STPS	4	25-Oct-03	500	ER	THERMAL	COAL	OIL	3,325	3,333,662		3339	3,187,703		3,511	3,335,782		1
TALCHER STPS	5	13-May-04	500	ER	THERMAL	COAL	OIL	1,684	1,688,576		3519	3,359,381		3,863	3,670,033		1
TALCHER STPS	6	06-Feb-05	500	ER	THERMAL	COAL	OIL	3	2,730		2480	2,367,573		3,923	3,726,505		1
BANDEL	**0**		**540**	**ER**	**THERMAL**	**COAL**	**OIL**	**1,935**	**2,515,327**	**1**	**1853**	**2,525,307**	**1**	**1,380**	**1,845,730**	**1**	
BANDEL	1	30-Nov-65	82.5	ER	THERMAL	COAL	OIL										
BANDEL	2	31-May-66	82.5	ER	THERMAL	COAL	OIL										
BANDEL	3	30-Nov-65	82.5	ER	THERMAL	COAL	OIL										
BANDEL	4	31-May-67	82.5	ER	THERMAL	COAL	OIL										
BANDEL	5	08-Oct-82	210	ER	THERMAL	COAL	OIL										
SANTALDIH	**0**		**480**	**ER**	**THERMAL**	**COAL**	**OIL**	**1,140**	**1,766,983**	**1**	**1046**	**1,576,619**	**1**	**1,245**	**1,986,937**	**1**	
SANTALDIH	1	01-Jan-74	120	ER	THERMAL	COAL	OIL										
SANTALDIH	2	16-Jul-75	120	ER	THERMAL	COAL	OIL										
SANTALDIH	3	06-Dec-78	120	ER	THERMAL	COAL	OIL										
SANTALDIH	4	30-Mar-81	120	ER	THERMAL	COAL	OIL										
KOLAGHAT	**0**		**1260**	**ER**	**THERMAL**	**COAL**	**OIL**	**6,638**	**10,301,662**	**1**	**6508**	**9,988,356**	**1**	**6,794**	**9,852,122**	**1**	
KOLAGHAT	1	13-Aug-90	210	ER	THERMAL	COAL	OIL										
KOLAGHAT	2	16-Dec-85	210	ER	THERMAL	COAL	OIL										
KOLAGHAT	3	24-Jul-84	210	ER	THERMAL	COAL	OIL										
KOLAGHAT	4	28-Dec-93	210	ER	THERMAL	COAL	OIL										
KOLAGHAT	5	17-Mar-91	210	ER	THERMAL	COAL	OIL										
KOLAGHAT	6	16-Jan-93	210	ER	THERMAL	COAL	OIL										
BAKRESWAR	**0**		**630**	**ER**	**THERMAL**	**COAL**	**OIL**	**3,762**	**4,643,818**	**1**	**3947**	**4,699,567**	**1**	**4,470**	**5,549,232**	**1**	
BAKRESWAR	1	18-Jul-99	210	ER	THERMAL	COAL	OIL	1,439	1,776,260		1291	1,536,780		1,513			
BAKRESWAR	2	20-May-00	210	ER	THERMAL	COAL	OIL	891	1,099,590		1493	1,777,702		1,505			
BAKRESWAR	3	01-Apr-01	210	ER	THERMAL	COAL	OIL	1,434	1,769,583		1163	1,385,160		1,452			

NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2005	LOCA-TION	TYPE	FUEL 1	FUEL 2	2004-2005 Net Gen GWh	2004-2005 Abs. Emis. t CO2	2004-2005 in OM	2005-2006 Net Gen GWh	2005-2006 Abs. Emis. t CO2	2005-2006 in OM	2006-2007 Net Gen GWh	2006-2007 Abs. Emis. t CO2	2006-2007 in OM	2006-2007 in BM
D.P.L.	**0**		**395**	**ER**	**THERMAL**	**COAL**	**OIL**	**1,836**	**2,979,085**	**1**	**1958**	**3,322,327**	**1**	**1,594**	**2,316,934**	**1**	
D.P.L.	1	31-Mar-60	30	ER	THERMAL	COAL	OIL										
D.P.L.	2	30-Apr-60	30	ER	THERMAL	COAL	OIL										
D.P.L.	3	12-Jun-64	75	ER	THERMAL	COAL	OIL										
D.P.L.	4	01-Sep-64	75	ER	THERMAL	COAL	OIL										
D.P.L.	5	31-May-66	75	ER	THERMAL	COAL	OIL										
D.P.L.	6	03-Jul-85	110	ER	THERMAL	COAL	OIL										
NEWCOSSIPORE	**0**		**160**	**ER**	**THERMAL**	**COAL**	**n/a**	**438**	**870,631**	**1**	**406**	**813,574**	**1**	**439**	**895,270**	**1**	
NEWCOSSIPORE	1	31-Oct-49	30	ER	THERMAL	COAL	OIL										
NEWCOSSIPORE	2	30-Nov-49	30	ER	THERMAL	COAL	OIL										
NEWCOSSIPORE	3	31-Oct-50	50	ER	THERMAL	COAL	OIL										
NEWCOSSIPORE	4	30-Apr-63	50	ER	THERMAL	COAL	OIL										
TITAGARH	**0**		**240**	**ER**	**THERMAL**	**COAL**	**OIL**	**1,636**	**1,948,138**	**1**	**1671**	**2,023,357**	**1**	**1,676**	**2,056,741**	**1**	
TITAGARH	1	12-Dec-82	60	ER	THERMAL	COAL	OIL										
TITAGARH	2	26-Apr-83	60	ER	THERMAL	COAL	OIL										
TITAGARH	3	16-Jan-84	60	ER	THERMAL	COAL	OIL										
TITAGARH	4	17-Mar-85	60	ER	THERMAL	COAL	OIL										
SOUTHERN REPL.	**0**		**135**	**ER**	**THERMAL**	**COAL**	**OIL**	**909**	**1,092,840**	**1**	**902**	**1,080,120**	**1**	**919**	**1,100,414**	**1**	
SOUTHERN REPL.	1	12-Aug-90	67.5	ER	THERMAL	COAL	OIL										
SOUTHERN REPL.	2	10-Apr-91	67.5	ER	THERMAL	COAL	OIL										
BUDGE BUDGE	**0**		**500**	**ER**	**THERMAL**	**COAL**	**OIL**	**3,455**	**3,547,271**	**1**	**4000**	**4,082,263**	**1**	**4,015**	**3,993,179**	**1**	
BUDGE BUDGE	1	16-Sep-97	250	ER	THERMAL	COAL	OIL	1,804	1,852,565								
BUDGE BUDGE	2	06-Mar-99	250	ER	THERMAL	COAL	OIL	1,650	1,693,679								
FARAKKA STPS	**0**		**1600**	**ER**	**THERMAL**	**COAL**	**OIL**	**8,877**	**8,990,312**	**1**	**10660**	**10,575,971**	**1**	**10,638**	**10,479,538**	**1**	
FARAKKA STPS	1	01-Jan-86	200	ER	THERMAL	COAL	OIL										
FARAKKA STPS	2	24-Dec-86	200	ER	THERMAL	COAL	OIL										
FARAKKA STPS	3	06-Aug-87	200	ER	THERMAL	COAL	OIL										
FARAKKA STPS	4	25-Sep-92	500	ER	THERMAL	COAL	OIL										
FARAKKA STPS	5	16-Feb-94	500	ER	THERMAL	COAL	OIL										
MUZAFFARPUR	**0**		**220**	**ER**	**THERMAL**	**COAL**	**OIL**	**0**	**0**	**1**	**0**	**0**		**0**	**0**	**1**	
MUZAFFARPUR	1	31.03.1985	110	ER	THERMAL	COAL	OIL										
MUZAFFARPUR	2	17.03.1986	110	ER	THERMAL	COAL	OIL										

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BOKARO A	**0**		**175**	**ER**	**THERMAL**	**COAL**	**OIL**	**0**	**0**	**1**	**0**	**0**		**0**	**0**	**1**	
BOKARO A	1	30.11.1951	45	ER	THERMAL	COAL	OIL										
BOKARO A	2	30.11.1951	45	ER	THERMAL	COAL	OIL										
BOKARO A	3	30.11.1952	45	ER	THERMAL	COAL	OIL										
BOKARO A	4	31.10.1960	40	ER	THERMAL	COAL	OIL										
MULAJORE	**0**		**120**	**ER**	**THERMAL**	**COAL**	**OIL**	**0**	**0**	**1**	**0**	**0**		**0**	**0**	**1**	
MULAJORE	1	01.07.1992	30	ER	THERMAL	COAL	OIL										
MULAJORE	2	01.07.1992	30	ER	THERMAL	COAL	OIL										
MULAJORE	3	01.07.1992	30	ER	THERMAL	COAL	OIL										
MULAJORE	4	01.07.1992	30	ER	THERMAL	COAL	OIL										
KOSI	**0**		**20**	**ER**	**HYDRO**			**3**	**0**		**17**	**0**		**17**	**0**		
KOSI	1	1-Mar-1970	5	ER	HYDRO												
KOSI	2	16-Apr-1971	5	ER	HYDRO												
KOSI	3	20-Oct-1973	5	ER	HYDRO												
KOSI	4	1-Oct-1978	5	ER	HYDRO												
SONE WEST CANAL	**0**		**6.6**	**ER**	**HYDRO**			**13**	**0**		**17**	**0**		**17**	**0**		
SONE WEST CANAL	1	1-Mar-1993	1.65	ER	HYDRO												
SONE WEST CANAL	2	8-Mar-1993	1.65	ER	HYDRO												
SONE WEST CANAL	3	28-Aug-1993	1.65	ER	HYDRO												
SONE WEST CANAL	4	30-Mar-1994	1.65	ER	HYDRO												
SONE EAST CANAL	**0**		**3.3**	**ER**	**HYDRO**			**12**	**0**		**12**	**0**		**8**	**0**		
SONE EAST CANAL	1	26-Jun-1996	1.65	ER	HYDRO												
SONE EAST CANAL	2	29-Feb-1996	1.65	ER	HYDRO												
E.G. CANAL	**0**		**15**	**ER**	**HYDRO**			**21**	**0**		**28**	**0**		**25**	**0**		
E.G. CANAL	1	4-Aug-1995	5	ER	HYDRO												
E.G. CANAL	2	22-Jun-1996	5	ER	HYDRO												
E.G. CANAL	3	12-Nov-1997	5	ER	HYDRO			7									
SUBERNREKHA I&II	**0**		**130**	**ER**	**HYDRO**			**147**	**0**		**51**	**0**		**207**	**0**		
SUBERNREKHA-I	1	14-Oct-1977	65	ER	HYDRO												
SUBERNREKHA -II	2	18-Oct-1980	65	ER	HYDRO												
PANCHET	**0**		**80**	**ER**	**HYDRO**			**134**	**0**		**86**	**0**		**163**	**0**		
PANCHET	1	14-Sep-1959	40	ER	HYDRO												
PANCHET	2	8-Mar-1991	40	ER	HYDRO												

NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2005	LOCA-TION	TYPE	FUEL 1	FUEL 2	2004-2005 Net Gen GWh	2004-2005 Abs. Emis. t CO2	2004-2005 in OM	2005-2006 Net Gen GWh	2005-2006 Abs. Emis. t CO2	2005-2006 in OM	2006-2007 Net Gen GWh	2006-2007 Abs. Emis. t CO2	2006-2007 in OM	2006-2007 in BM
MAITHON	**0**		**63.2**	**ER**	**HYDRO**			**113**	**0**		**85**	**0**		**174**	**0**		
MAITHON	1	28-Oct-1957	20	ER	HYDRO												
MAITHON	2	21-May-1958	20	ER	HYDRO												
MAITHON	3	12-Dec-1958	23.2	ER	HYDRO												
TILLAYA	**0**		**4**	**ER**	**HYDRO**			**12**	**0**		**3**	**0**		**18**	**0**		
TILLAYA	1	21-Feb-1953	2	ER	HYDRO												
TILLAYA	2	10-Jul-1953	2	ER	HYDRO												
BALIMELA	**0**		**360**	**ER**	**HYDRO**			**1,519**	**0**		**1048**	**0**		**1,615**	**0**		
BALIMELA	1	14-Aug-1973	60	ER	HYDRO												
BALIMELA	2	25-Jan-1974	60	ER	HYDRO												
BALIMELA	3	24-Aug-1974	60	ER	HYDRO												
BALIMELA	4	26-Mar-1975	60	ER	HYDRO												
BALIMELA	5	7-May-1976	60	ER	HYDRO												
BALIMELA	6	7-May-1976	60	ER	HYDRO												
HIRAKUD I&II	**0**		**331.5**	**ER**	**HYDRO**			**838**	**0**		**904**	**0**		**858**	**0**		
HIRAKUD-I	1	1-Nov-1958	49.5	ER	HYDRO												
HIRAKUD-I	2	11-Nov-1957	49.5	ER	HYDRO												
HIRAKUD-I	3	18-Dec-1956	24	ER	HYDRO												
HIRAKUD-I	4	13-May-1957	24	ER	HYDRO												
HIRAKUD-I	5	19-Apr-1962	37.5	ER	HYDRO												
HIRAKUD-I	6	5-Aug-1963	37.5	ER	HYDRO												
HIRAKUD-I	7	13-Sep-1990	37.5	ER	HYDRO												
HIRAKUD-II	8	15-Jul-1962	24	ER	HYDRO												
HIRAKUD-II	9	26-Nov-1962	24	ER	HYDRO												
HIRAKUD-II	10	1-Feb-1964	24	ER	HYDRO												
RENGALI	**0**		**250**	**ER**	**HYDRO**			**745**	**0**		**674**	**0**		**667**	**0**		
RENGALI	1	27-Aug-1985	50	ER	HYDRO												
RENGALI	2	26-Mar-1986	50	ER	HYDRO												
RENGALI	3	10-Aug-1989	50	ER	HYDRO												
RENGALI	4	19-Mar-1990	50	ER	HYDRO												
RENGALI	5	24-Jul-1992	50	ER	HYDRO												

NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2005	LOCA-TION	TYPE	FUEL 1	FUEL 2	2004-2005 Net Gen GWh	2004-2005 Abs. Emis. t CO2	2004-2005 in OM	2005-2006 Net Gen GWh	2005-2006 Abs. Emis. t CO2	2005-2006 in OM	2006-2007 Net Gen GWh	2006-2007 Abs. Emis. t CO2	2006-2007 in OM	2006-2007 in BM
UPPER KOLAB	**0**		**320**	**ER**	**HYDRO**			**892**	**0**		**621**	**0**		**1,021**	**0**		
UPPER KOLAB	1	10-Mar-1988	80	ER	HYDRO												
UPPER KOLAB	2	14-Apr-1989	80	ER	HYDRO												
UPPER KOLAB	3	10-Aug-1990	80	ER	HYDRO												
UPPER KOLAB	4	12-Jan-1993	80	ER	HYDRO												
UPPAR INDRAVATI	**0**		**600**	**ER**	**HYDRO**			**2,836**	**0**		**1754**	**0**		**3,006**	**0**		
UPPAR INDRAVATI	1	9-May-1999	150	ER	HYDRO			709						752			
UPPAR INDRAVATI	2	23-Dec-1999	150	ER	HYDRO			709			439			752			
UPPAR INDRAVATI	3	30-Sep-2000	150	ER	HYDRO			709			439			752			
UPPAR INDRAVATI	4	30-Mar-2001	150	ER	HYDRO			709			439			752	0		
JALDHAKA I&II	**0**		**35**	**ER**	**HYDRO**			**162**	**0**		**169**	**0**		**146**	**0**		
JALDHAKA -I	1	31-Mar-1967	9	ER	HYDRO												
JALDHAKA -I	2	3-Mar-1967	9	ER	HYDRO												
JALDHAKA -I	3	26-Nov-1972	9	ER	HYDRO												
JALDHAKA -II	4	5-Aug-1983	4	ER	HYDRO												
JALDHAKA -II	5	5-Aug-1983	4	ER	HYDRO												
RAMMAM	**0**		**50**	**ER**	**HYDRO**			**240**	**0**		**196**	**0**		**230**	**0**		
RAMMAM	1	5-Sep-1995	12.5	ER	HYDRO												
RAMMAM	2	28-Sep-1995	12.5	ER	HYDRO												
RAMMAM	3	13-Jan-1996	12.5	ER	HYDRO												
RAMMAM	4	28-Jan-1996	12.5	ER	HYDRO												
TEESTA I-III	**0**		**67.5**	**ER**	**HYDRO**			**103**	**0**		**101**	**0**		**34**	**0**		
TEESTA -I	1	14-Dec-1997	7.5	ER	HYDRO			11									
TEESTA -I	2	25-Jan-1998	7.5	ER	HYDRO			11									
TEESTA -I	3	19-Apr-1998	7.5	ER	HYDRO			11									
TEESTA -II	4	10-Apr-1998	7.5	ER	HYDRO			11									
TEESTA -II	5	22-Oct-1998	7.5	ER	HYDRO			11									
TEESTA -II	6	30-Mar-1999	7.5	ER	HYDRO			11									
TEESTA -III	7	23-Jul-1999	7.5	ER	HYDRO			11			11						
TEESTA -III	8	7-Sep-1999	7.5	ER	HYDRO			11			11						
TEESTA -III	9	13-Oct-1999	7.5	ER	HYDRO			11			11						
LOWER LAGYAP	**0**		**12**	**ER**	**HYDRO**			**31**	**0**		**18**	**0**		**17**	**0**		
L.LAGYAP	1	1-Sep-1979	6	ER	HYDRO												
L.LAGYAP	2	2-Nov-1979	6	ER	HYDRO												

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U.ROGNICHU	**0**		**8**	**ER**	**HYDRO**			**13**	**0**		**11**	**0**		**12**	**0**		
U.ROGNICHU	1	5-Mar-1993	2	ER	HYDRO												
U.ROGNICHU	2	21-Nov-1993	2	ER	HYDRO												
U.ROGNICHU	3	2-Mar-1994	2	ER	HYDRO												
U.ROGNICHU	4	26-Mar-1994	2	ER	HYDRO												
MOYAGCHU	**0**		**4**	**ER**	**HYDRO**			**18**	**0**		**4**	**0**		**6**	**0**		
MOYAGCHU	1	1-Jul-1993	2	ER	HYDRO												
MOYAGCHU	2	1-Jul-1993	2	ER	HYDRO												
RANGIT-III	**0**		**60**	**ER**	**HYDRO**			**369**	**0**		**350**	**0**		**200**	**0**		
RANGIT-III	1	5-Feb-2000	20	ER	HYDRO			123			117						
RANGIT-III	2	5-Feb-2000	20	ER	HYDRO			123			117						
RANGIT-III	3	5-Feb-2000	20	ER	HYDRO			123			117						
CHHUKHA	**0**		**336**	**BHUTAN**	**HYDRO**			**1,764**	**0**		**1932**	**0**		**1,830**	**0**		
CHHUKHA	1	1986-88	4X84.00	BHUTAN	HYDRO												
KURICHU (MONGAR)	**0**		**60**	**BHUTAN**	**HYDRO**			**340**	**0**		**366**	**0**		**374**	**0**		
KURICHU (MONGAR)	1	2001	4X15.00	BHUTAN	HYDRO												
BASOCHU (WANGDUE)	**0**		**64**	**BHUTAN**	**HYDRO**			**231**	**0**		**332**	**0**		**314**	**0**		
BASOCHU-I (WANGDUE)	1	2002	2X12.00	BHUTAN	HYDRO									111			1
BASOCHU-II (WANGDUE)	2	2004	2X20.00	BHUTAN	HYDRO									204			1
TALA	**0**		**64**	**BHUTAN**	**HYDRO**									**1,980**	**0**		
TALA	1	2006	1020	BHUTAN	HYDRO									1,980			1

Annex 4

MONITORING INFORMATION

DATA RECORDING

Task: Recording of electricity generation data of the project
Responsible: Project Authority
Time: monthly

DATA COLLECTION

Task: Delivery of monthly net generation to DHPC
Responsible: Project Authority
Time: monthly, per email

EMISSION REDUCTION CALCULATION USING EXCEL SPREADSHEET

$ER=EF_y*EG_y$
Where
ER = Emission Reduction
EF_y = Baseline emission factor (tCO2/MWh) =1.004
EG_y = Net annual electricity generation at Dagachhu HPP (MWh)

MONITORING REPORT

Task: Preparation of Monitoring Report
Responsible: Project Authority - DHPC
Time: at the beginning of each year
Contents: excel spreadsheets including data collected and emission reduction calculation

Submit monitoring report to Designated Operational Entity

Is any additional information required?

yes

No

Verification and certification by Designated Operational Entity

Issuances of CERs by CDM Executive Board