CARBON TRADING THROUGH CLEAN DEVELOPMENT MECHANISM FOR SMALL SCALE PROJECTS

A DISSERTATION

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By

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CANDIDATE'S DECLARATION

I hereby declare that the dissertation titled **"Carbon Trading through Clean Development Mechanism for Small Scale Projects** " which is being submitted in partial fulfillment of the requirements for the award of Degree of Master of Technology in Water Resources Development (Civil) at Department of Water Resources Development and Management (WRD&M), Indian Institute of Technology, Roorkee is an authentic record of my own work carried out during the period of June, 2006 to June, 2007 under the supervision and guidance of **Professor Umesh Chandra Chaube**, WRD&M, IIT, Roorkee.

I have not submitted the matter embodied in this dissertation for the award of any other degree.

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LIST OF ABBREVIATIONS

A&R	Afforestation and Reforestation
AEs	Applicant Entities
CDM	Clean Development Mechanism
CDM-AP	CDM Assessment Panel
CDM-AT	CDM Assessment Team
CERs	Certified Emission Reductions
CH4	Methane
COP	Conference of Parties
DNA	Designated National Authority
DOE	Designated Operational Entity
DSCR	Debt Service Coverage Ratio
EB	Executive Board
EIA	Environmental Impact Assessment
ERPA	Emission Reduction Purchase Agreement
GHGs	Green house Gases
HFCs	Hydroflurocarbons
IBRD	International Bank for Reconstruction and Development
IRR	Internal Rate of Return
LULUCF	Land Use, Land Use Change and Forestry
M&P	Modalities & Procedures
MW	Mega Watt
N2O	Nitrous oxide
NGOs	Non Government Organisations
ODA	Official Development Assistance
PCF	Prototype Carbon Fund
PDD	Project Design Document
PFCs	Perfluorocarbons
SBSTA	Subsidiary Body for Scientific and Technological Advice
tCERs	Temporary CERs
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
WMO	World Meteorological Organisation

ABSTRACT

This dissertation covers review of Clean Development Mechanism as applied to small scale projects along with two case studies (Biogas Support Programme and Microhydro Village Electrification Project in Nepal).

An international treaty on global climate protection known as the United Nations Framework Convention on Climate Change (UNFCCC) came into force on March 21, 1994. The Convention required industrialized countries (Annex I Parties) to take the lead in returning their greenhouse gas emissions to 1990 levels by the year 2000. During 3rd Conference of Parties (COP3) in Kyoto, Japan, , on 11 December 1997, a legally binding set of obligations called the **Kyoto protocol** for 38 industrialized countries and 11 countries in Central and Eastern Europe was created, to return their emissions of GHGs to an average of approximately 5.2% below their 1990 levels over the commitment period 2008-2012. The Kyoto Protocol entered into force on 16 February 2005 with its ratification by Russia and as on June 20, 2007, 175 Parties have ratified the Protocol. The targets cover six main greenhouse gases. Some activities in the land-use change and forestry sector, such as afforestation and reforestation, that absorb carbon dioxide from the atmosphere, are also covered. The Protocol establishes three cooperative mechanisms (**International Emission Trading, Joint Implementation and Clean Development Mechanism**) designed to help industrialized countries reduce the costs of meeting their emissions targets by achieving emission reductions at lower costs in other countries than they could domestically.

The CDM is supervised by the Executive Board, composed of 10 members, including one representative from each of the five official UN regions (Africa, Asia, Latin America and the Caribbean, Central Eastern Europe, and OECD), one from the small island developing states, and two each from Annex I and non-Annex I Parties. All parties (Annex I and non-Annex I Parties) must meet three basic requirements to participate in CDM: i) voluntary participation, ii) establishment of the National CDM Authority, iii) ratification of the Kyoto Protocol. In order to make small projects competitive with larger ones, the Marrakech Accords establish a fast track for small-scale projects with simpler eligibility rules—renewables up to 15 MW, energy efficiency with a reduction of consumption either on the supply or the demand side of

up to 15 gigawatthours/yr, and other projects that both reduce emissions and emit less than 15 kilotons of CO2 equivalent annually.

The CDM project cycle follows seven steps 1) Project design and formulation, 2) National approval, 3) Validation and registration, 4) Project finance, 5) Monitoring, 6) Verification/certification and 7) Issuance of CERs. All countries wishing to participate in the CDM must designate a National CDM Authority to evaluate and approve the projects, and serve as a point of contact. In India, the Ministry of Environment and Forests (MoEF), which is the nodal agency for the subject issues of climate change, has been made the host of the DNA for dealing with the CDM and other climate change issues. In Nepal, Ministry of Environment, Science and Technology (MoEST) has been made to host the DNA for dealing with the CDM and other climate change issues.

CDM projects produce both conventional project output and carbon benefits (CERs). The value of carbon benefits and its impact on project viability are influenced by several factors such as the amount of CERs generated by the project, the price of CER and the transaction costs involved in securing CERs. The World Bank's PCF and the Dutch Government's C-ERUPT tender are the current main buyers of CERs through direct purchase transactions. Three new public-private partnership funds have been recently launched by the World Bank: the Community Development Carbon Fund, the Bio-Carbon Fund and the Italian Carbon Fund. The fragmented nature of the global carbon market generates differentiated prices for emissions reductions. Allowance markets generate high emission reduction prices since the delivery risks are believed to be minimal. The current price spread of CERs is US$ 3 – 6 per TCO2e.

The total energy consumption in Nepal was 8.62 million toe in 2005, which translates to per capita annual energy consumption of about 15 Giga Joule (GJ), ranks among the lowest of the world. The energy mix is lopsided in Nepal, with biomass (fuel wood, agricultural residue and animal dung) being the main energy providers, supplying an overall 88% of the total energy consumed. Fuel wood, representing 78% of the energy consumption, is mainly used in rural Nepal. Energy end-uses of the domestic sector are mainly for cooking and lighting. The total demand of 331 million GJ in the domestic sector in 2004/05 was met mostly by fuel wood, followed by 16.2% agricultural residue.

As part of this dissertation work, the project design document for two renewable energy projects have been prepared as case studies. The Nepal Biogas Support Programme is considered the project activity that installed a total of 9,759 small biogas digesters from April 07, 2005 to December, 2005 across various locations in 55 districts out of 75 districts of Nepal. It is estimated that the project activity will result in approximately 327,243 tons of net emission reductions over a crediting life of 7 years (2007-2014).

The other Micro Hydro Village Electrification CDM Project aims to reduce GHG emissions and to contribute to the sustainable development of the rural villages by constructing micro hydroelectric power stations with a total power generation capacity of 2556 kW in the unelectrified 150 rural villages of 25 districts of Nepal which are off grid locations. It is estimated that the project activity will result in approximately 18771.26 tons of net emission reductions over a crediting life of 7 years (2009-2016).

Carbon trading is in Nepal's favor. In order to benefit from these opportunities, such as Biogas Support Programme and Microhydro Village Electrification Projects under CDM should be considered on priority basis. Carbon revenues earned from selling the generated CERs helps in the sustainability of both Biogas Support Programme and Microhydro Village Electrification Project.

CHAPTER-1

INTRODUCTION

This chapter explains the background of the existence of United Nations Framework Convention on Climate Change and Kyoto Protocol. An overview of clean development mechanism is presented along with the small scale CDM project categories.

1.1 THE INTERNATIONAL CONCERN

There is increasing scientific evidence of human interference with the global climate system, along with growing public concern about the environment. In 1988, the United Nations Environment Programme (UNEP) and the World Meteorological Organization (WMO) established the Intergovernmental Panel on Climate Change (IPCC). It published its first report in 1990 concluding that the growing accumulation of human-made greenhouse gases in the atmosphere would "enhance the greenhouse effect, resulting on average in an additional warming of the Earth's surface" by the next century, unless measures were adopted to limit emissions. The report confirmed that climate change was a threat and called for an international treaty to address the problem. The Second World Climate Conference in 1990 echoed the same call. The United Nations General Assembly responded by formally launching negotiations on a framework convention on climate change and establishing an "Intergovernmental Negotiating Committee" to develop a treaty. Negotiations to formulate an international treaty on global climate protection began in 1991 and resulted in the completion, by May 1992, of the United Nations Framework Convention on Climate Change (UNFCCC).

The UNFCCC was opened for signature at the UN Conference on Environment and Development (the Earth Summit) in Rio de Janeiro, Brazil, in June 1992, and entered into force in March 21, 1994. The Convention sets an "ultimate objective" of stabilizing atmospheric concentrations of greenhouse gases at safe levels. Such levels, which the Convention does not quantify, should be achieved within a time frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner. To achieve this objective, all countries have a general commitment to address climate change, adapt to its effects, and report their actions to implement the Convention. As on 8th June, 2007, the Convention currently has received 191 instruments of ratification.

The Convention divides countries into two groups: the industrialized countries (Annex I Parties) who have historically contributed the most to climate change, and the developing countries (Non-Annex 1 Parties). **Annex I** Parties include the industrialized countries that were members of the OECD (Organisation for Economic Co-operation and Development) in 1992, plus countries with economies in transition (the EIT Parties), including the Russian Federation, the Baltic States, and several Central and Eastern European States. The list of Annex 1 Parties is given below in Table-1.1.

Table-1.1: List of Annex-1 (developed) Countries

S.N.	Country	S.N.	Country	S.N.	Country
1	Australia	15	Greece	29	Poland
2	Austria	16	Hungary	30	Portugal
3	Belarus	17	Iceland	31	Romania
4	Belgium	18	Ireland	32	Russian Federation
5	Bulgaria	19	Italy	33	Slovakia
6	Canada	20	Japan	34	Slovenia
7	Croatia	21	Latvia	35	Spain
8	Czech Republic	22	Liechtenstein	36	Sweden
9	Denmark	23	Lithuania	37	Switzerland
10	Estonia	24	Luxembourg	38	Turkey
11	European Community	25	Monaco	39	Ukraine
12	Finland	26	Netherlands	40	UK
13	France	27	New Zealand	41	USA
14	Germany	28	Norway		

Source: www.cdm.unfccc.int

The principles of equity and "common but differentiated responsibilities" contained in the Convention require Annex I Parties to take the lead in returning their greenhouse gas emissions to 1990 levels by the year 2000. They must also submit regular reports, known as national communications, detailing their climate change policies and programs, as well as annual inventories of their GHG emissions.

1.2 THE KYOTO PROTOCOL AND THE MARRAKECH ACCORDS

Kyoto Protocol: The Convention established the Conference of Parties (COP) as its supreme body with the responsibility to oversee the progress toward the aim of the Convention. At the first session of the COP (COP 1) in Berlin, Germany, it was decided that post 2000 commitments would only be set for Annex I Parties. During COP 3 in Kyoto, Japan, on 11 December 1997, a legally binding set of obligations for

38 industrialized countries and 11 countries in Central and Eastern Europe was created, to return their emissions of GHGs to an average of approximately 5.2% below their 1990 levels over the commitment period 2008-2012. This is called the **Kyoto Protocol** to the Convention. The Kyoto Protocol entered into force on 16 February 2005 with its ratification by Russia and as on June 20, 2007, 175 Parties have ratified the Protocol.

The targets cover six main greenhouse gases given below. The Protocol also allows these countries the option of deciding which of the six gases will form part of their national emissions reduction strategy. Some activities in the land-use change and forestry sector, such as afforestation and reforestation, that absorb carbon dioxide from the atmosphere, are also covered.

The six GHGs are not equal in terms of global warming potential (GWP), which measures the relative radiative effect of GHGs compared to CO2. For example, one ton of methane has a GWP as potential as 21 ton of CO2.

Greenhouse gas	Global warming potential
1. Carbon dioxide (CO_2)	1
2. Methane (CH_4)	21
3. Nitrous oxide (N_2O)	310
4. Hydrofluorocarbons (HFCs)	140–11,700
5. Perfluorocarbons (PFCs)	6,500–9,200
6. Sulfur hexafluoride (SF_6)	23,900

The Marrakech Accords: While the Protocol identified a number of modalities to help Parties reach their targets, it does not elaborate on the specifics. After more than four years of debate, Parties agreed at COP 7 in Marrakech, Morocco to a comprehensive rulebook – the Marrakech Accords – on how to implement the Kyoto Protocol. The Accords also intend to provide Parties with sufficient clarity to consider ratification.

1.3 COOPERATIVE MECHANISMS

The Protocol establishes three cooperative mechanisms designed to help Annex I Parties reduce the costs of meeting their emissions targets by achieving emission reductions at lower costs in other countries than they could domestically. These are the following:

- **International Emissions Trading** permits countries to transfer parts of their 'allowed emissions' (assigned amount units).
- **Joint Implementation (JI)** allows countries to claim credit for emission reduction that arise from investment in other industrialized countries, which result in a transfer of 'emission reduction units' between countries.
- **Clean Development Mechanism (CDM)** explained in the next section allows emission reduction projects that assist developing countries in achieving sustainable development and that generate 'certified emission reductions' (CERs) for use by the investing countries or companies.

The mechanisms give countries and private sector companies the opportunity to reduce emissions anywhere in the world, wherever the cost is lowest, and they can then count these reductions towards their own targets. Any such reduction, however, should be supplementary to domestic actions in the Annex I countries. Through emission reduction projects, the mechanisms could stimulate international investment and provide the essential resources for cleaner economic growth in all parts of the world. The CDM, in particular, aims to assist developing countries in achieving sustainable development by promoting environmentally friendly investment from industrialized country governments and businesses.

1.4 OVERVIEW OF THE CLEAN DEVELOPMENT MECHANISM

1.4.1 The objective of CDM

The funding channelled through the CDM should assist developing countries in reaching some of their economic, social, environmental and sustainable development objectives, such as cleaner air and water, improved land-use, accompanied by social benefits such as rural development, employment, and poverty alleviation and in many cases, reduced dependence on imported fossil fuels. In addition to catalyzing green investment priorities in developing countries, the CDM offers an opportunity to make progress simultaneously on climate, development, and local environmental issues. For developing countries that might otherwise be preoccupied with immediate economic and social needs, the prospect of such benefits should provide a strong incentive to participate in the CDM.

The CDM allows industrialized countries (Annex I Party) to implement a project that reduces greenhouse gas emissions or, subject to constraints, removes greenhouse gases by carbon sequestration, or "sinks," in the territory of a developing country (Non-Annex I Party). The resulting certified emission reductions (CERs), can then be used by the industrialized countries to help meet its emission reduction target.

1.4.2 Administration

The CDM is supervised by the Executive Board, which itself operates under the authority of the Parties. The Executive Board is composed of 10 members, including one representative from each of the five official UN regions (Africa, Asia, Latin America and the Caribbean, Central Eastern Europe, and OECD), one from the small island developing states, and two each from Annex I and non-Annex I Parties.

The Executive Board will accredit independent organizations – known as operational entities– that will validate proposed CDM projects, verify the resulting emission reductions, and certify those emission reductions as CERs. Another key task of the EB is the maintenance of a CDM registry, which will issue new CERs, manage an account for CERs levied for adaptation and administration expenses, and maintain a CER account for each non-Annex I Party hosting a CDM project.

1.4.3 Participation

All parties (Annex I and non-Annex I Parties) must meet three basic requirements: i) voluntary participation, ii) establishment of the National CDM Authority, iii) ratification of the Kyoto Protocol. Annex I Parties moreover must meet additional requirements such as the following: i) establishment of the assigned amount under Article 3 of the Protocol, ii) national system for the estimation of greenhouse gases, iii) national registry, iv) annual inventory, and v) accounting system for the sale and purchase of emission reductions.

1.4.4 Project Eligibility

All projects that satisfy the additionality and sustainable development criteria are acceptable under the CDM. For the normal CDM, no positive list of project types has been made. However, limitations have been set on the following projects:

- Forestry: Sink projects allowed are only afforestation and reforestation, and Annex I Parties can only add CERs generated from sink projects to their assigned amounts up to 1% of their baseline emissions for the first commitment period. Guidelines for carbon sinks are being developed to ensure they are environmentally sound. At COP9, an annex to the modalities and procedures for CDM on how to treat afforestation and reforestation project activities was decided.

- Nuclear energy: Annex I Parties must refrain from using CERs generated through nuclear energy to meet their targets.

Additionality: The project activity is expected to result in GHG emission reduction, which is additional to any that would occur in the absence of the certified project activity, i.e. it should not be included in the baseline. The additionality should be shown by following the additionality part of the methodologies approved by the EB. Some examples of how to demonstrate the additionality of a project are given below:

(a) A flow-chart or series of questions that lead to a narrowing of potential baseline options.

(b) A qualitative or quantitative assessment of different potential options and an indication of why the non-project option is more likely.

(c) A qualitative or quantitative assessment of one or more barriers facing the proposed project activity (such as laid out for small-scale CDM projects.

(d) An indication that the project type is not common practice in the proposed area of implementation, and not required by a Party's legislation/ regulation.

Sustainable Development: The purpose of the CDM is to assist non-Annex I Parties in achieving sustainable development. There is no common guideline for the sustainable development criterion and it is up to the developing host countries to determine their own criteria and assessment process. The criteria for Sustainable Development may be broadly categorised as:

- **Social criteria:** The project improves the quality of life, alleviates poverty, and improves equity.
- **Economic criteria:** The project provides financial returns to local entities, results in positive impact on balance of payments, and transfers new technology.
- **Environmental criteria:** The project reduces greenhouse gas emissions and the use of fossil fuels, conserves local resources, reduces pressure on the local environments, provides health and other environmental benefits, and meets energy and environmental policies.

The CDM will include projects in the following sectors:

- Renewable energy
- End-use energy efficiency improvements

- Supply-side energy efficiency improvement
- Fuel switching
- Agriculture (reduction of CH4 and N2O emissions)
- Industrial processes (CO2 from Cement etc., HFCs, PFCs, SF6)
- Solvent and other product use
- Waste management
- Sinks projects (only afforestation and reforestation)

In order to make small projects competitive with larger ones, the Marrakech Accords establish a fast track for small-scale projects with simpler eligibility rules. The Executive Board had been tasked with defining modalities and procedures for the fast track, and submitted them to the Eighth Conference of the Parties (COP 8), held in New Delhi in October 2002. To facilitate the development of small-scale projects, simplified modalities and procedures were developed to reduce transaction costs. The EB has decided that a project can have more than one host country. This could be relevant for cross border transmission lines, or hydro projects on rivers running along borders.

1.4.5 Bundling and debundling

Bundling will reduce the transaction cost because a large number of small projects can be combined in one PDD. Projects may be bundled as long as the total size is below the limits for a single project as listed for the three small scale project types below in section 1.5.

Debundling a large CDM project into consecutive small-scale parts is not eligible for a small-scale CDM project if the total is greater than the small-scale project eligibility. The EB has elaborated a procedure as an annex to the modalities and procedures for small-scale CDM, which shall be applied to a small-scale project to assess whether it is a debundled portion of a larger project. The procedure is defined as follows:

A proposed small-scale project activity shall be deemed to be a debundled component of a large project activity if there is a registered small-scale CDM project activity or an application to register another small-scale CDM project activity:

- with the same project participants;
- in the same project category and technology/measure; and
- registered within the previous 2 years; and

- whose project boundary is within 1 km of the project boundary of the proposed small-scale activity at the closest point.

1.5 SMALL-SCALE CDM PROJECTS CATEGORIES

According to modalities and procedures for the CDM, three types of small-scale CDM projects as described below are possible. For the first two, there is a maximum size of the activity that reduces emissions, but for the third type, there is a maximum on the total emission from the project at the end of the project activity.

I. Renewable energy project activities with a maximum output capacity equivalent of up to 15 MW (or an appropriate equivalent)

II. Energy efficiency improvement project activities which reduce energy consumption, on the supply and/or demand side, by up to the equivalent of 15 GWh per year; or

III. Other project activities that both reduce anthropogenic emissions by sources and directly emit less than 15 thousand tonnes (kt) of carbon dioxide equivalent annually.

These three types are interpreted by the EB as mutually exclusive. For example when a 60 MW wind turbine project is not eligible for type I, it cannot be eligible for type III either, even though it emits less than 15 kt CO2. Table 1.2 shows a list of eligible small-scale CDM projects.

If a new project belongs to none of the existing categories of small-scale projects, the project developer should propose a new category. to the EB before submitting a project PDD. The proposal must include a description of how a simplified baseline and monitoring methodology would be applied to the new category. Once the EB accepts a proposed new category, the EB will amend Table-1.2 and its appendix to the small-scale modalities and procedures to include the new category. The project developer may then submit the project PDD in this new category to the EB for consideration.

Another general condition for small-scale CDM projects is related to the combination of renewable and non-renewable components within the boundary of one project. If the project adds a unit that has both renewable and non-renewable components, the eligibility limit of 15 MW applies only to the renewable component.

Table-1.2: The EB's present version of small-scale CDM project activity categories

Project types	Reference	Small-scale CDM project activity categories
Type I: Renewable energy projects	AMS-I.A	Electricity generation by the user
	AMS-I.B	Mechanical energy for the user
	AMS-I.C	Thermal energy for the user
	AMS-I.D	Renewable electricity generation for a grid
Type II: Energy efficiency improvement projects	AMS-II.A	Supply side energy efficiency improvements-transmission and distribution
	AMS-II.B	Supply side energy efficiency improvements– generation
	AMS-II.C	Demand-side energy efficiency programmes for specific technologies
	AMS-II.D	Energy efficiency and fuel switching measures for industrial facilities
	AMS-II.E	Energy efficiency and fuel switching measures for buildings
	AMS-II.F	Energy efficiency and fuel switching measures for agricultural facilities and activities
Type III: Other project activities	AMS-III.A	Agriculture
	AMS-III.B	Switching fossil fuels
	AMS-III.C	Emission reductions by low-greenhouse gas emission vehicles
	AMS-III.D	Methane recovery in agricultural and agro industrial activities
	AMS-III.E	Avoidance of methane production from biomass decay through controlled combustion
	AMS-III.F	Avoidance of methane production from decay of biomass through composting
	AMS-III.G	Landfill methane recovery
	AMS-III.H	Methane recovery in wastewater treatment
	AMS-III.I	Avoidance of methane production in wastewater treatment through replacement of anaerobic lagoons by aerobic systems
	AMS-III.J	Avoidance of fossil fuel combustion for carbon dioxide production to be used as raw material for industrial processes
	AMS-III.K	Avoidance of methane release from charcoal production by shifting from pit method to mechanized charcoaling process
	AMS-III.L	Avoidance of methane production from biomass decay through controlled pyrolysis
	AMS-III.M	Reduction in consumption of electricity by recovering soda from paper manufacturing process

Source: http://www.cdm.unfccc.int

1.5.1 Sink Projects

Only afforestation and reforestation (A&R) projects are eligible and the maximum use of CERs from A&R projects should be less than 1% of the 1990 emissions of the Party. Other sinks like revegetation, forest management, cropland management and grazing land management are not allowed under the CDM but only as Joint Implementation projects in Annex-I countries.

The A&R terms are defined in the following way:

Afforestation is the direct human-induced conversion of land that has not been forested for a period of at least 50 years into forested land through planting/ seeding.

Reforestation is in the first commitment period (2008-2012) limited to lands that did not contain forest on 31 December 1989.

There are some restrictions on the definition of a forest. The DNA in the CDM host country should make an assessment and report the value in each of the following three categories, which will be used for all projects in the first commitment period in the country:

- A minimum tree cover of 10-30%
- A minimum forest area of 0.05 – 1.00 ha
- A minimum tree height of 2-5 metres

The Land Use, Land Use Change and Forestry (LULUCF) Modalities and Procedures (M&P) contain only the following rules for small-scale CDM projects:

- The greenhouse gas removal of less than 8 ktCO2/year.
- The projects must be developed by low-income communities and individuals as determined by the host Party.

The M&P also contains the following important rules:

Since the benefits from sink projects accrue over longer periods of time than benefits from other CDM projects the crediting period will be longer than for normal CDM projects. The crediting period begins at the start of the afforestation or reforestation project activity. Just like normal CDM projects, there are two options for the crediting period:

- A maximum of 20 years which may be renewed two times, provided a DOE confirms that the baseline is still valid or has been properly updated taking into account of new data.
- A maximum of 30 years.

All carbon stored must be accounted. The following carbon pools are defined:

- Above-ground biomass
- Dead wood
- Litter
- Below-ground biomass
- Soil organic carbon

A carbon pool can be excluded from the emission accounting in the project if that does not increase the net GHG removal.

The procedure for establishing baseline and monitoring methodologies is the same as that for normal full-scale CDM projects. There is no methodology at the beginning. Methodologies will be approved by the EB as project participants submit them for approval. The project participants must base these new methodologies on one of the following three approaches:

1. Existing or historical changes in carbon stocks in the carbon pools within the project boundary.
2. Changes in carbon stocks in the carbon pools within the project boundary from land use that represent an economically attractive course of action, taking into account barriers of investment.
3. Changes in carbon stocks within the project boundary from the most likely land use at the time the project starts.

The PDDs for LULUCF CDM projects will contain the same information as for normal PDDs:

However, there will be some additional requirements:

- The project description must contain the exact location of the projects, a list of the carbon pools selected, the present environmental conditions, the legal title of the land, the current land tenure and the right of access.
- There must always be an analysis of the environmental & socio-economic impact. If negative impacts are considered significant by the project participants or the host party, an environmental/socio-economic impact analysis must be made.
- The DOE which validates the CDM project must make the PDD available for public comments in a period of 45 days (30 days for normal CDM projects).
- Management activities, including harvesting cycles, means that the carbon stored can vary over time. Therefore the time of verification should be selected in such a way as the systematic coincidence of verification and peaks in the carbon stored can be avoided.

The project participant must in the PDD choose one of the two options:

- tCERs or 'temporary CERs' that expires at the end of the commitment period following the one during which it was issued.

- lCERs or 'long-term CERs' that expires at the end of the crediting period chosen.
- The initial verification and certification by a DOE may be undertaken at a time selected by the project participants. In order to show the permanence of the carbon stored, both tCERs and lCERs should be verified and certified every 5 years thereafter.

Environmental NGOs had been very eager that large monoculture industrial plantations (including genetically modified trees) should be excluded because they threaten biological diversity, watershed protection, and local sustainable livelihoods. They urged parties to explicitly ask for multi-species cultures that increase or at least preserve biodiversity. However, the negotiation ended up with a text (the M&P) saying that it is up to the host country to evaluate the risks associated with the use of potentially invasive alien species and genetically modified organisms.

The COP had invited the Intergovernmental Panel on Climate Change (IPCC) to elaborate methods to estimate, measure, monitor and report changes in carbon stock and GHG emissions. This IPCC report called "Good Practice Guidance for LULUCF in the preparation of national greenhouse gas inventories under the Convention" was finally approved at COP9. The baseline and monitoring methodologies and the Project Design Document (PDD) should be consistent with this document.

1.6 BENEFITS TO A DEVELOPING COUNTRY

The basic principle of the CDM is simple, developed countries can invest in low cost abatement opportunities in developing countries and receive credit for the resulting emissions reductions, thus reducing the cutbacks needed within their borders. While the CDM lowers the cost of compliance with the Protocol for developed countries, developing countries will benefit as well, not just from the increased investment flows, but also from the requirement that these investments advance sustainable development goals. The CDM encourages developing countries to participate by promising that development priorities and initiatives will be addressed as part of the package. This recognizes that only through long-term development will all countries be able to play a role in protecting the climate.

From the developing country perspective, the CDM can:

- Attract capital for projects that assist in the shift to a more prosperous but less carbon-intensive economy;

- Encourage and permit the active participation of both private and public sectors;
- Provide a tool for technology transfer, if investment is channelled into projects that replace old and inefficient fossil fuel technology, or create new industries in environmentally sustainable technologies; and,
- Help define investment priorities in projects that meet sustainable development goals.

Specifically, the CDM can contribute to a developing country's sustainable development objectives through:

- Transfer of technology and financial resources;
- Sustainable ways of energy production;
- Increasing energy efficiency & conservation;
- Poverty alleviation through income and employment generation; and,
- Local environmental side benefits

The drive for economic growth presents both threats and opportunities for sustainable development. While environmental quality is an essential element of the development process, in practice, there is considerable tension between economic and environmental objectives. Increased access to energy and provision of basic economic services, if developed along conventional paths, could cause long-lasting environmental degradation, both locally and globally. But by charting a different course and providing the technological and financial assistance to follow it, many potential problems could be avoided.

In comparing potential CDM projects with what might otherwise take place, it is clear that the majority will entail not only carbon reduction benefits, but also produce a range of environmental and social benefits within developing countries. Sustainable development benefits could include reductions in air and water pollution through reduced fossil fuel use, especially coal and oil, but also extend to improved water availability, reduced soil erosion and protected biodiversity. For social benefits, many projects would create employment opportunities in target regions or income groups and promote local energy self-sufficiency. Therefore carbon abatement and sustainable development goals can be simultaneously pursued.

Many options under the CDM could create significant co-benefits in developing countries, addressing local and regional environmental problems and advancing social goals. For developing countries that might otherwise give priority to immediate economic and environmental needs, the prospect of significant ancillary benefits should provide a strong inducement to participate in the CDM.

1.7 OBJECTIVES AND SCOPE OF THE STUDY

Objectives of the Study: The objectives of this study are (i) to increase awareness and understanding of various aspects of CDM (ii) o build capacities in the baseline methodology and assessment of GHG emission reductions/sequestration benefits and (iii) to illustrate procedure for preparation of Project Design Documents (PDD) of Small Scale CDM projects through case studies of biogas and micro hydro schemes in Nepal.

Scope of the Study: This study has focus on Clean Development Mechanism for Small Scale Projects in India and Nepal. In this context various aspects of CDM have been reviewed and presented in a systematic and easily understandable format so as to serve as guidelines for preparation of Small Scale CDM project (SSCDMP) Documents.

Following two categories of SSCDMPs are considered relevant

(i) Biogas Support Program in Nepal

(ii) Micro Hydropower Village Electrification Project in Nepal

Data required for study of these two SSCDMPs have been collected by visiting various agencies in Nepal. Project Design Document have been prepared for the two SSCDMPs in accordance with the format specified by CDM Executive Board of United Nations framework Convention on Climatic Change (UNFCCC).

1.8 RELEVANT WEBSITES

The list of literatures reviewed for the preparation of this dissertation report has been presented in reference list. Following websites have been searched in detail for the preparation of this dissertation report:

http://www.cdm.unfccc.int
http://www.cd4cdm.org
http://www.unep.org
http://www.adb.org/clean-energy
http://www.prototypecarbonfund.org
http://www.carbonfinance.org
http://www.cdmindia.nic.in
http://www.communitycarbonfund.org
http://www.redp.org.np
http://www.envfor.nic.in
http://www.cea.nic.in
http://www.moest.gov.np
http://www.aepcnepal.org
http://www.bspnepal.org.np

CHAPTER-2

THE CDM PROJECT CYCLE AND APPROVAL PROCESS IN INDIA AND NEPAL

This chapter explains the stages of a CDM project cycle and the project approval process followed in India and Nepal. Detailed procedures for project design document formulation are given in chapter-3.

2.1 THE CDM PROJECT CYCLE

The CDM project cycle has seven steps:

• Project design and formulation, • National approval, • Validation and registration, • Project finance,	Prior to the implementation of the project
• Monitoring, • Verification/certification and • Issuance of CERs.	During the lifetime of the project

Figure-2.1 shows the institutions involved in the process and the reports which must be produced. Project participants are Parties to the Kyoto protocol or a private and/or public entity authorized by a Party to participate in CDM projects under the Party's responsibility. Unique to the CDM projects are the steps to generate emission credits such as baseline setting, validation, registration, monitoring and verification/ certification of emissions reduction.

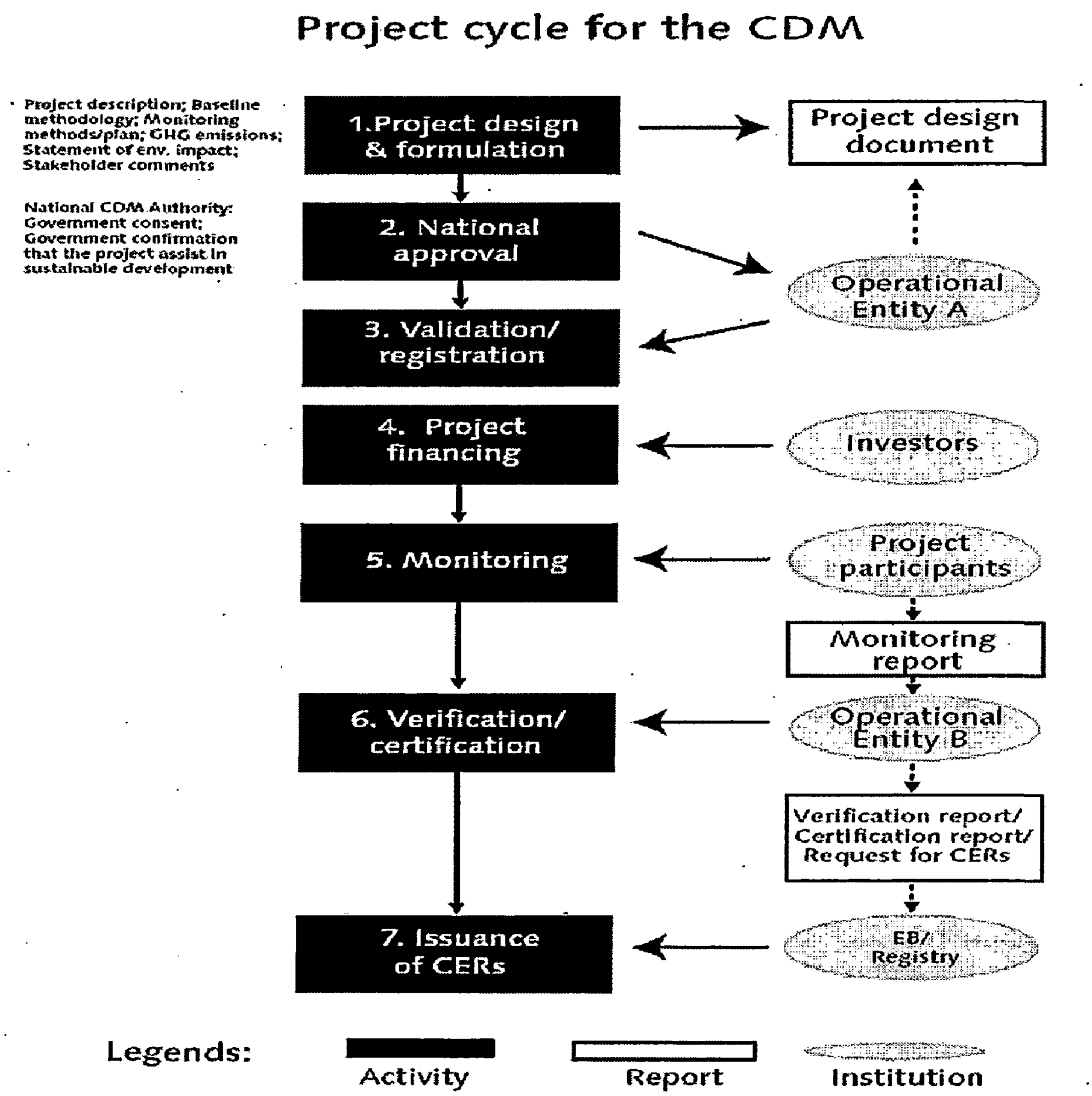
2.2 PROJECT DESIGN AND FORMULATION

CDM projects must result in real and measurable climate change benefits and should be additional to any that would occur in the absence of the project activity. To establish additionality, the project emissions must be compared to the emissions of a reasonable reference case, identified as the baseline. The baseline will be established on a project-specific basis by the project participants complying with approved methodologies. These baseline methodologies are being developed on the basis of three approaches in the Marrakech Accord:

- Existing actual or historical emissions;

- Emissions from a technology that represents an economically attractive investments; or,
- Average emissions of similar project activities undertaken in the previous five years under similar circumstances and whose performance is among the top 20% of their category.

Figure 2.1: Project cycle for the CDM



Source: Introduction to the CDM, UNEP RISOE CENTRE, 2002

CDM projects must also have a monitoring plan to collect accurate emissions data. The monitoring plan, which constitutes the basis of future verification, should provide confidence that the emission reductions and other project objectives are being achieved and should be able to monitor the risks inherent to baseline and project emissions. The monitoring plan can be established either by the project developer or by a specialized agent. The baseline and monitoring plan must be devised according to approved methodologies. If the project participants prefer a new methodology, it must be authorized and registered by the Executive Board. The project participants must choose whether the crediting period shall be 10 years or 7 years with a possibility to be renewed two times (a maximum of 21 years). However, for small-scale CDM projects, simplified baseline methodologies and monitoring plans can be used.

2.3 NATIONAL APPROVAL

One purpose of the CDM is to assist developing countries in achieving sustainable development. The developing country government is responsible for screening the projects and deciding whether a project meets that requirement. The host country should therefore develop national criteria and requirements to ensure a coherent, justifiable and transparent assessment. It is important that these criteria are in agreement with national development priorities.

All countries wishing to participate in the CDM must designate a National CDM Authority to evaluate and approve the projects, and serve as a point of contact. Although the international process has given general guidelines on baselines and additionality, each developing country has the responsibility to determine the national criteria for project approval. Together with the investor, the host country must prepare a project design document with the following structure:

- General description of the project;
- Description of the baseline methodology;
- Timeline and crediting period;
- Monitoring methodology and plan;
- Calculation of GHG emissions by sources
- Statement of environmental impacts;
- Stakeholder comments.

The National CDM Authority issues the necessary statements: that the government participates voluntary in the project and confirms that the project activity assists the host country in achieving sustainable development.

2.3.1 Designated CDM National Authority (DNA) in India

India is a Party to the United Nations Framework Convention on Climate Change (UNFCCC) and the objective of the Convention is to achieve stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system.

India acceded to the Kyoto Protocol in August 2002 and one of the objectives of acceding was to fulfill prerequisites for implementation of Clean Development Mechanism (CDM) projects, in accordance with national sustainable priorities, where-under, a developed country would take up greenhouse gas reduction project activities in developing countries where the costs of greenhouse gas reduction project activities are usually much lower with the purpose to assist developing country parties in achieving Sustainable Development and in contributing to the ultimate objective of the Convention and to assist developed country Parties in achieving compliance with their quantified emission limitation and reduction commitments.

After India's ratification of the Kyoto Protocol, the central government of India constituted the National CDM Authority (NCA) for the purpose of protecting and improving the quality of the environment in terms of the Kyoto Protocol. The government accorded approval for setting up the DNA in December 2003, coinciding with the Ninth Conference of Parties (COP 9). The DNA is hosted by the Ministry of Environment and Forests (MoEF) and headed by the secretary of the MoEF. Thus, the MoEF, which is the nodal agency for the subject issues of climate change, was made the host of the DNA for dealing with the CDM and other climate change issues. It is the ministry responsible for developing an institutional framework for developing CDM projects in the country, as well as endorsing CDM projects.

The DNA was set up by the MoEF, under the powers conferred on it by sub-section (1) and (3) of section 3 of the Environment Protection Act (EPA), 1986 (29 of 1986). The composition of the "National Clean Development Mechanism (CDM) Authority" is as follows:

Table 2.1: The Composition of the National CDM Authority

1.	Secretary (Environment and Forests)	Chairperson
2.	Foreign Secretary or his nominee	Member
3.	Finance Secretary or his nominee	Member
4.	Secretary, Industrial Policy and Promotion or his nominee	Member
5.	Secretary, Ministry of Non Conventional Energy Sources or his nominee	Member
6.	Secretary, Ministry of Power or his nominee	Member
7.	Secretary, Planning Commission or his nominee	Member
8	Joint Secretary (Climate Change), Ministry of Environment and Forests	Member
9.	Director (Climate Change), Ministry of Environment and Forests	Member-Secretary

Source: Ministry of Environment and Forest, India

The National Clean Development Mechanism (CDM) Authority receives projects for evaluation and approval as per the guidelines and general criteria laid down in the relevant rules and modalities pertaining to CDM in addition to the guidelines issued by the Clean Development Mechanism Executive Board and Conference of Parties serving as Meeting of Parties to the United Nations Framework Convention on Climate Change.

The evaluation process of CDM projects includes an assessment of the probability of eventual successful implementation of CDM projects and evaluation of extent to which projects meet the sustainable development objectives, as it would seek to prioritize projects in accordance with national priorities.

The National Clean Development Mechanism (CDM) Authority can recommend certain additional requirements to ensure that the project proposals meet the national sustainable development priorities and comply with the legal framework so as to ensure that the projects are compatible with the local priorities and stakeholders have been duly consulted.

The Authority ensures that in the event of project proposals competing for same source of investment, projects with higher sustainable development benefits and which are likely to succeed are accorded higher priority.

The Authority also carries out the financial review of project proposals to ensure that the project proposals do not involve diversion of official development assistance in accordance with modalities and procedures for Clean Development Mechanism and also ensure that the market environment of the CDM project is not conducive to under-valuation of Certified Emission Reduction (CERs) particularly for externally aided projects.

The Authority carries out activities to ensure that the project developers have reliable information relating to all aspects of Clean Development Mechanism which include creating databases on organizations designated for carrying out activities like validation of CDM project proposals and monitoring and verification of project activities, and to collect, compile and publish technical and statistical data relating to CDM initiatives in India.

The Member-Secretary of the National Clean Development Mechanism (CDM) Authority is responsible for day-to-day activities of the Authority including constituting committees or sub-groups to coordinate and examine the proposals or to get detailed examination of the project proposals.

The National Clean Development Mechanism (CDM) Authority has the powers:

- to invite officials and experts from Government, financial institutions, consultancy organizations, non-governmental organizations, civil society, legal profession, industry and commerce, as it may deem necessary for technical and professional inputs and may co-opt other members depending upon need.
- to interact with concerned authorities, institutions, individual stakeholders for matters relating to CDM.
- to take up any environmental issues pertaining to CDM or Sustainable Development projects as may be referred to it by the Central Government, and
- to recommend guidelines to the Central Government for consideration of projects and principles to be followed for according host country approval.

ELIGIBILITY CRITERIA

The project proposal should establish the following in order to qualify for consideration as CDM project activity:

Additionalities

Emission Additionality: The project should lead to real, measurable and long term GHG mitigation. The additional GHG reductions are to be calculated with reference to a baseline. Financial Additionality: The procurement of Certified Emission Reduction (CERs) should not be from Official Development Assistance (ODA)

Sustainable Development Indicators

It is the prerogative of the host Party to confirm whether a clean development mechanism project activity assists it in achieving sustainable development. The CDM projects should also be oriented towards improving the quality of life of the poor from the environmental standpoint.

Following aspects should be considered while designing CDM project activity:

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

Economic well being: The CDM project activity should bring in additional investment consistent with the needs of the people

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

Technological well being: The CDM project activity should lead to transfer of environmentally safe and sound technologies that are comparable to best practices in order to assist in upgradation of the technological base. The transfer of technology can be within the country as well from other developing countries also.

Baselines

The project proposal must clearly and transparently describe methodology of determination of baseline. It should confirm to following:

- Baselines should be precise, transparent, comparable and workable;
- Should avoid overestimation;
- The methodology for determination of baseline should be homogeneous and reliable;
- Potential errors should be indicated;
- System boundaries of baselines should be established;
- Interval between updates of baselines should be clearly described;
- Role of externalities should be brought out (social, economic and environmental);
- Should include historic emission data-sets wherever available;

- Lifetime of project cycle should be clearly mentioned;

The project proponent could develop a new methodology for its project activity or could use one of the approved methodologies by the CDM Executive Board. For small scale CDM projects, the simplified procedures can be used by the project proponent. The project proposal should indicate the formulae used for calculating GHG offsets in the project and baseline scenario. Leakage, if any, within or outside the project boundary, should be clearly described. Determination of alternative project, which would have come up in absence of proposed CDM project activity should also be described in the project proposal.

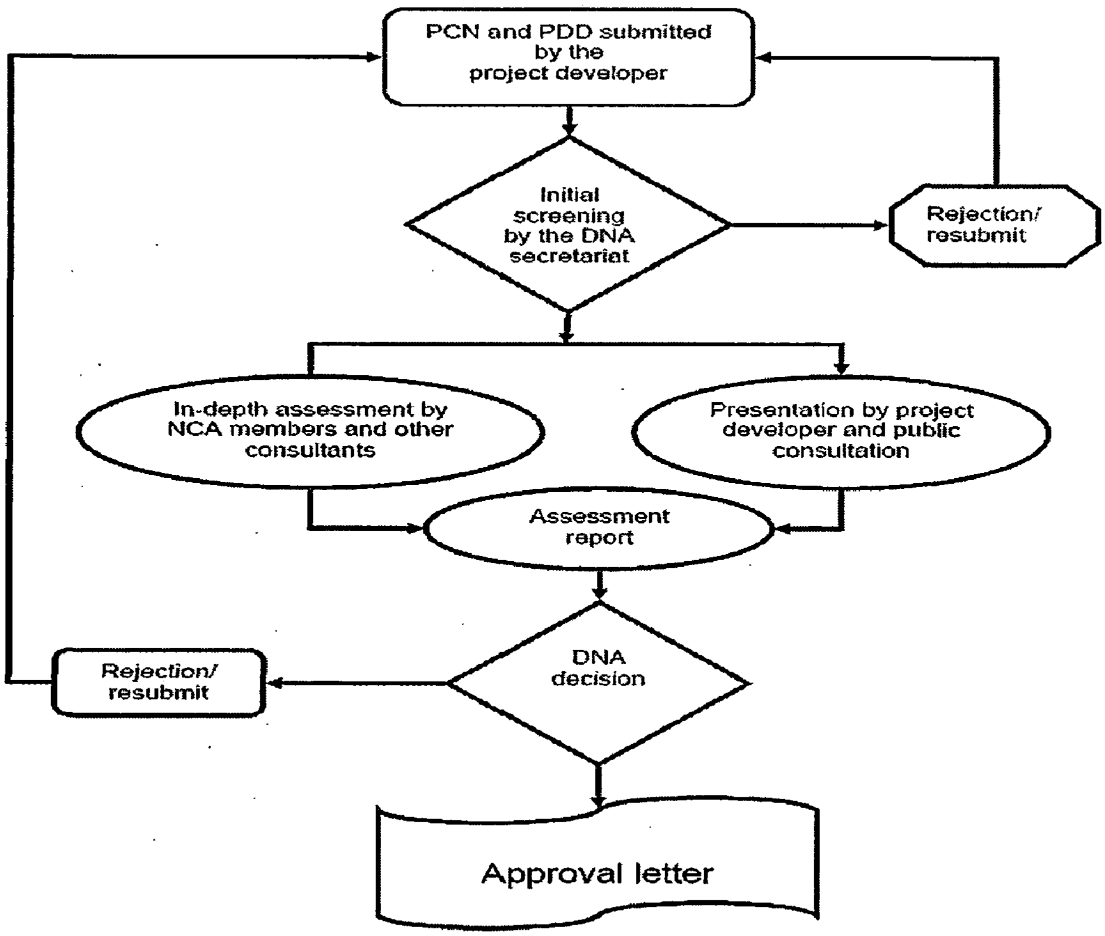
APPROVAL PROCESS

Procedure for Submitting CDM Project Reports to the National CDM Authority

The National CDM Authority is a single window clearance for CDM projects in the country. The project proponents are required to submit one soft copy of Project Concept Note (PCN) and Project Design Document (PDD) through online form and 20 hardcopies each of PCN and PDD along with two CDs containing all the information in each of them.

The project report and CDs should be forwarded through covering letter signed by the project sponsors. The project report submitted should be properly bound. The National CDM Authority examines the documents and if there are any preliminary queries the same are asked from the project proponents. The project proposals are then put up for consideration by the National CDM Authority. The project proponent and his consultants are normally given about 10-15 days notice to come to the Authority meeting and give a brief power point presentation regarding their CDM project proposals. Members seek clarifications during the presentation and in case the members feel that some additional clarifications or information is required from the project proponent the same is informed to the presenter. Once the members of Authority are satisfied, the Host Country Approval (HCA) is issued by the Member-Secretary of the National CDM Authority. The flow chart of approval process is as shown below:

Figure 2.2: Flow chart of approval process of the National CDM Authority of India



Source: CDM Country Guide for India, Institute of Global Environmental Strategies (IGES), 2005

Contact Information

Mr. R. K. Sethi

Member Secrectary

The National CDM Authority (Designated National Authority (DNA)

Ministry of Environment and Forests

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C.G.O Complex, Lodhi Road

New Delhi - 110 003, INDIA

Telefax : +91 11 2436 2252, E-mail : dir.cc@nic.in, Website: cdmindia.nic.in

envfor.nic.in/cdm

2.3.2 Designated CDM National Authority (DNA) in Nepal

Nepal signed the United Nations Framework Convention on Climate Change (UNFCCC) on 12th June 1992 at Rio de Janeiro during the Earth Summit. In accordance with the Treaty Act of 1990, the House of Representatives (Lower House) ratified it on 2 May 1994, making it effective in Nepal three months later on 31st July 1994. As a Party to the Convention, Nepal has been actively participating in the Convention processes since then. In this connection the Ministry of Environment, Science and Technology (MoEST) with mandates for implementing the UNFCCC provisions is coordinating the activities related to the obligations.

As a Party to the Convention, Nepal started its implementation through the formulation of necessary policies and legislation. Major steps have been taken to minimize GHG emission from vehicular traffic. Government of Nepal (GoN), through the Ministry of Environment, Science and Technology, has also prepared a country profile to implement the Convention at the national level.

UNFCCC

- Adoption of the Convention: 9 May 1992
- Nepal's Signature: 12 June 1992
- Nepal's Ratification: 2 May 1994
- Entry into force: 21 March 1994 (global level)
- Entered into force in Nepal: 31 July 1994
- First Initial National Communication (INC) Report prepared with GEF/UNEP assistance: July 2004

Kyoto Protocol

- Entry into force (global): 16 February 2005
- Deposition of instrument of Accession: 16 September 2005
- Entry into force in Nepal: 14 December 2005

Clean Development Mechanism

- Ministry of Environment, Science and Technology (MoEST) designated as DNA: 22 December 2005
- 11 Member Steering Committee – 17 April 2006 for DNA activities
- MoEST-WB joint organization of a seminar on Capacity Building Needs for CDM: 1 August '06

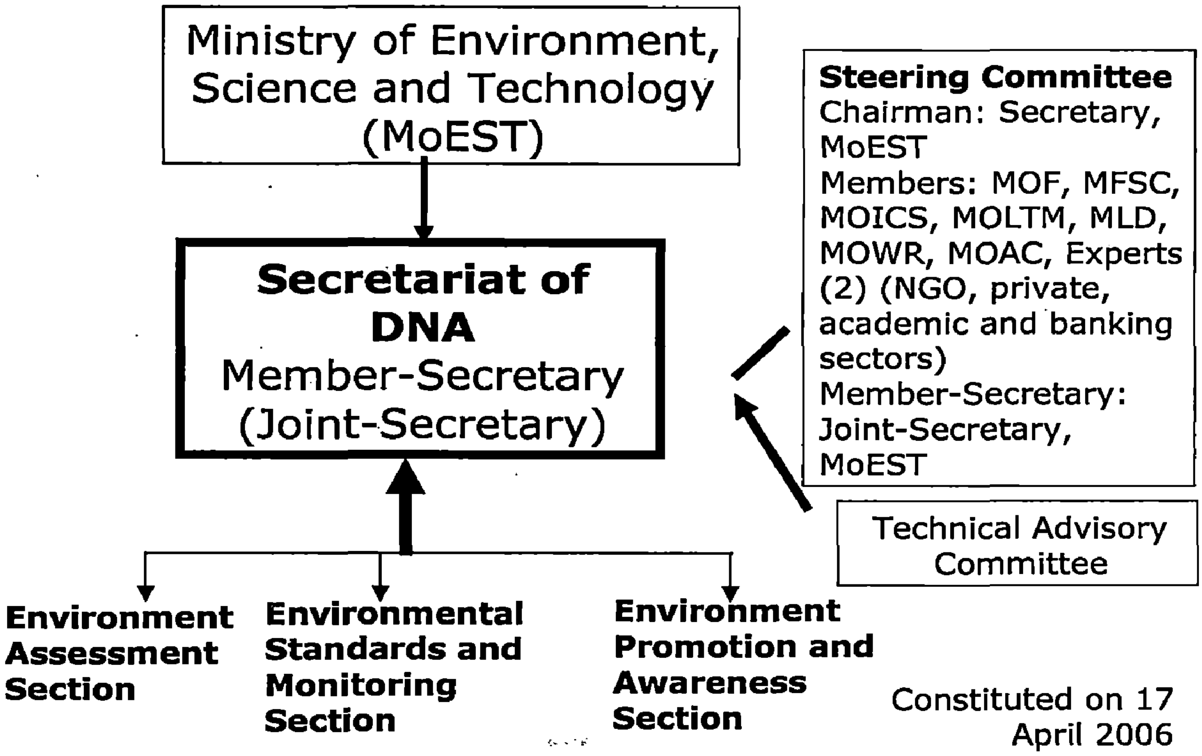
Policy Focus

Tenth Plan (2002-'07)

- Carbon trade for resource management and for poverty reduction
- Promotion of the use of environment-friendly technologies, cleaner production, energy efficiency, clean energy, and alternative energy
- Implementation of multilateral environmental agreements (MEAs) including UNFCCC

STRUCTURE OF DNA IN NEPAL

Figure 2.3: Organisation Chart of CDM Designated Authority in Nepal



Source: Ministry of Environment, Science and Technology, GoN

Nepal's Perspective of the Climate Regime beyond 2012

- The global impacts of Climate Change are real and now even more evident on many fronts of our lives
- Another commitment period should come into force with more sense of urgency and higher reduction targets

- Nepal and other south Asian nations are more at the receiving end of the Climate Change impacts
- The need for our efforts towards adaptation to the Climate Change impacts is more urgent and important to us
- Cooperation among South Asian nations to supplement to their current level of individual efforts to derive maximum benefits from the CDM
- Current provisions for funds/mechanisms for adaptation to be made more effective and secured for Least Developed Country's like Nepal
- Need to pay serious attention to the ecological fragility and vulnerability of mountainous nations like Nepal

Contact Information

Government of Nepal

Ministry of Environment Science and Technology

Singha Durbar, Kathmandu

Telephone: 977 (1) 4244609, 4247391, 4240654, 4222571, 4231172

Fascimile: 977 (1) 4225474

Email:info@most.gov.np Website: www.moest.gov.np

2.4 VALIDATION/ REGISTRATION

2.4.1 Validation

A designated operational entity (DOE), chosen by the project participants, will then review the project design document, invite feedbacks from NGOs and local communities, and decide whether or not it should be validated. These operational entities will typically be private companies such as auditing and accounting firms, consulting companies and law firms capable of conducting credible and independent assessments of emission reductions. If validated, the operational entity will forward it to the Executive Board for formal registration. The DOEs accredited by the EB will be listed on the UNFCCC CDM website.

The DOEs can be accredited for 15 sectoral scopes. The project participants should therefore check under which of the scopes their project fits, and choose for validation a DOE that is accredited for that scope. The definition of the scopes in Table-2.2 is based on the list of sectors/sources in Annex A of the Kyoto Protocol.

Some sectors are missing from the table, but the DOEs can propose new sectoral scopes.

Table- 2.2: Sectoral scopes for which AEs can be accredited

1	Energy industries (renewable / non-renewable sources)
2	Energy distribution
3	Energy demand
4	Manufacturing industries
5	Chemical industry
6	Construction
7	Transport
8	Mining/Mineral production
9	Metal production
10	Fugitive emissions from fuels (solid, oil and gas)
11	Fugitive emissions from production and consumption of halocarbons and sulphur hexafluoride
12	Solvents use
13	Waste handling and disposal
14	Afforestation and reforestation
15	Agriculture

Source: CDM Information and Guidebook, UNEP Resho centre

The DOE selected shall review the PDD and any supporting documentation to confirm if:

a) Parties in the project have ratified the Kyoto Protocol

b) The PDD has been publicly available, comments have been invited from local stakeholders for a period of 30 days, a summary of the comments provided with a report on how due account was taken of any comments.

c) Project participants have submitted to the DOE the analysis of the environmental impact of the project and, if the impacts are considered significant, have undertaken an environmental impact assessment following the procedures of the host Party.

d) The project activity is expected to result in a GHG emission reduction which is additional.

The baseline and monitoring methodologies are among those already approved by the EB, or a new methodology that has followed the Modalities and Procedures for establishing a new methodology.

Table-2.3 shows that a minimum estimate of the transaction cost for validation & certification of a CDM project is about US$70,000 and simplified procedures for small-scale CDM could reduce this to US$23,000.

Table- 2.3: Validation & verification costs

	Estimated costs (US$)
Baseline study	18,000 – 23,000
Monitoring plan	7,000 – 15,000
Validation	15,000 – 30,000
Legal & contractual arrangements	23,000 – 38,000
Verification	7,000 per audit

Source: EcoSecurities, May 2002

At the moment the EB is working to reduce the transaction costs for small-scale CDM projects. One possibility to reduce the transaction cost is to use DOEs based in developing countries. However, as yet there are very few AEs from developing countries. By PCF, the biggest transaction cost of a CDM contract to date is $300,000 as per their records.

2.4.2 Registration

At the 6th meeting of the EB, it was decided that a fee of between US$ 5,000 and 30,000 should be paid to the EB for the registration of a CDM project. Table-2.4 shows an EB decision that the registration fee for small-scale CDM projects has been reduced to US$5,000 and that for other CDM projects increases progressively to US$30,000 with annual emission reduction of the CDM project. This administration fee for examining the CDM projects for registration will be paid up-front but the fee will be deducted from the share of proceeds at the issuance of CERs.

With a bundling of small-scale projects, if the total size of the bundled project does not exceed a limit for small-scale, it can pay only US$5,000 which is for a small-scale CDM project. Therefore, bundling of many small projects within the limit of small-scale can save administration fee.

The EB must register the CDM project within 8 weeks (4 weeks for small-scale CDM projects) of the date of receipt of the request. If a request for a review has been made by a Party involved in the project activity or at least three members of the EB, the registration can be delayed until the next EB meeting for a review.

Table-2.4: Administration fee for a CDM project registration

Annual CO2-eq. reduction	Fee in US$
<=15,000	5,000
>15,000 and <= 50,000	10,000
>50,000 and <=100,000	15,000
>100,000 and <=200,000	20,000
>200,000	30,000

Source: unfccc

2.5 PROJECT FINANCING

With the validation and registration of the project, project developers will take actions to implement the project which will generate an emission reduction credit as well as other conventional benefits to create financial income. Project financing is a common and crucial part of project implementation in every project. There are multilateral and bilateral sources of funding to develop CDM projects. This project financing also involves risks from different sources and requires project developers to properly manage any potential risks, including project risks, political risks, and market risks. Project risks include whether the project meets all the requirements of the CDM and whether the project will generate the emission reduction credits estimated in the PDD. Political risks include the entry into force of the Kyoto Protocol and ratification of the Protocol by participating governments. Market risks include the price of CERs and transaction costs.

Public funding for CDM projects from Parties in Annex I is not to result in the diversion of official development assistance (ODA) and is to be separate from and not counted towards the financial obligations of Parties included in Annex I (Decision 17/CP.7, the Marrakech Accords).

2.6 MONITORING

The carbon component of a mitigation project cannot acquire value in the international carbon market unless submitted to a verification process designed specifically to measure and audit the carbon component. Therefore, once project is operational, participants prepare a monitoring report, including an estimate of CERs generated and submit it for verification to an operational entity.

Monitoring is a systematic surveillance of a project's performance by measuring and recording target indicators relevant to the objective of the project. The project's developers should prepare a monitoring plan which is transparent, reliable and relevant. Therefore, the monitoring plan needs to provide detailed information related to the collection and archiving of all relevant data necessary to

- estimate GHG emissions occurring within the project boundary;
- determine the baseline GHG emissions;
- determine the leakage.

As an example, the following information should be monitored:

- Fuel consumption
- Activity levels
- Emission factors
- Heat produced and replaced
- Electricity produced and replaced
- Grid losses
- Fuel prices/subsidies/taxes

If the project is a demand-side energy efficiency project consisting of many devices, it is costly to monitor all of them. For Small-Scale projects it is therefore suggested that it is enough to monitor an appropriate sample of the devices installed. For technologies with fixed loads while operating, such as lamps, the sample can be small while for technologies that involve variable loads, such as air conditioners, the sample may need to be relatively large. In either case, monitoring should include annual checks of a sample of non-metered devices to insure that they are still operating. Monitoring should consist of monitoring the "power" and "operating hours" or the "energy use" of the device installed using an appropriate methodology.

The Marrakech Accords shows necessary information which a monitoring plan should provide as follows:

- The collection and archiving of all relevant data necessary for estimating or measuring anthropogenic emissions by sources of greenhouse gases occurring within the project boundary during the crediting period;

- The collection and archiving of all relevant data necessary for determining the baseline of anthropogenic emissions by sources of greenhouse gases within the project boundary during the crediting period;
- The identification of all potential sources of, and the collection and archiving of data on, increased anthropogenic emissions by sources of greenhouse gases outside the project boundary that are significant and reasonably attributable to the project activity during the crediting period;
- The collection and archiving of information relevant to assess the environmental impacts of the project, including trans-boundary impacts;
- Quality assurance and control procedures for the monitoring process;
- Procedures for the periodic calculation of the reduction of anthropogenic emissions by sources by the proposed CDM project activity, and for leakage effects;
- Documentation of all steps involved in the calculations of leakage and the procedures for the periodic calculation of the emission reductions during the lifetime of the project.

Monitoring shall be planned and implemented by project participants. A monitoring methodology connected to the baseline methodology must be chosen in the database on the CDM homepage.

2.7 VERIFICATION/CERTIFICATION

Verification is the periodic independent review and ex post determination by the DOE of the monitored reductions in anthropogenic emissions by sources of GHGs that have occurred as a result of a registered CDM projects activity during the verification period. It will include the periodic auditing of monitoring results, the assessment of achieved emission reductions and the assessment of the project's continued conformance with monitoring plan. The operational entity must make sure that the CERs have resulted according to the guidelines and conditions agreed upon in the initial validation of the project. Following a detailed review, an operational entity will produce a verification report and then certify the amount of CERs generated by the CDM project.

According to paragraph 27 (c) of the Modalities and Procedures, an Operational Entity cannot normally perform the verification/certification of a CDM project if it has validated the same project. This is only possible for Small-Scale CDM projects and for single projects where the EB gives permission.

Certification is a written assurance by the DOE that, during a specified time period, a project activity achieved the reductions in anthropogenic emissions by sources of GHGs as verified. The DOE shall inform the project participants, Parties involved and the EB of its certification decision in writing immediately upon completion of the certification process and make the certification report publicly available. The certification report shall constitute a request to the EB for issuance of CERs equal to the verified amount of reductions of anthropogenic emissions of GHGs. Unless a project participant or three Executive Board members request a review within 15 days, the Executive Board will instruct the CDM registry to issue the CERs.

2.8 ISSUANCE OF CERS

The EB must issue the CERs to the project partners within 15 days after the date of receipt of the request for issuance. As early as possible in the project design negotiations, contracts on carbon credit ownership must be made between the project participants. The rights and obligations of each participant should be clear. These rights could include the option to sell CERs to third parties. The contract should also specify the insurance coverage on the project and it should stipulate the rules for resolution of disputes between the parties. In addition two percent of the CERs issued must be paid to assist in meeting the costs of adaptation. The least developed countries are exempted from this fee.

The CDM Registry being developed by the UNFCCC Secretariat will keep track of all issuances of CERs. When the EB has issued the CERs they are placed in a pending account in the CDM Registry. From here the CERs will move to the Party's legal entity's account according to a split specified in the request from project participant.

CHAPTER-3

THE PROCEDURE FOR PREPARATION OF PROJECT DESIGN DOCUMENT

This chapter explains the basic contents of the Project Design Document and baseline methodologies for small scale CDM project activities for the assessment of GHG emission.

3.1 THE PROJECT DESIGN DOCUMENT (PDD)

In order to get a CDM project approved and registered by the Executive Board (EB), the project participants must prepare a Project Design Document (PDD) following the detailed outline shown on the CDM website of the UNFCCC Secretariat http://www.cdm.unfccc.int. The present outline of the PDD for small scale CDM project is shown in Table-3.1.

Table-3.1: Required Content of a Project Design Document (PDD)

A.	General description of project activity
B.	Baseline methodology
C.	Duration of the project activity/crediting period
D.	Monitoring methodology and plan
E.	Calculation of GHG emission by sources
F.	Environmental impacts
G.	Stakeholder's comments
Annex 1.	Contact information of project participants
Annex 2.	Information regarding public funding

3.2 GENERAL DESCRIPTION OF PROJECT ACTIVITY

This section of PDDs (section A) should include the following information:

- Project title
- Short description of the project activity
- the purpose of the project activity
- the view of the project participants of the project activity's contribution to sustainable development (max. one page)
- List of Party(ies) and private and/or public entities involved in the project activity.

- Information allowing a unique identification of the project activity, including the location.
- Specification of project activity category(ies) using the list on the UNFCCC CDM website.
- Brief explanation of how GHG emission is reduced.
- Information of public funding and affirmation that it does not result in a diversion of official development assistance.
- Confirmation that the project activity is not a debundled component of a larger project activity.

3.3 BASELINE METHODOLOGIES FOR VARIOUS SMALL SCALE PROJECTS

This section of PDDs (section B) should include the following information:

- Title and reference to the UNFCCC CDM website for the project category applicable to the project activity.
- Justification of the choice of methodology.
- Explanation of how and why the project is additional and therefore not the baseline scenario.
- Description of the project boundary.
- Details of the baseline and its development.

For the small-scale CDM, standardized baselines are already in place. They are defined in Appendix B of "Simplified Modalities and Procedures for the small scale CDM": "Indicative simplified baseline and monitoring methodologies for selected small-scale CDM project activity categories" and are described in the section below.

The EB has in its "Further Clarifications on Methodological Issues" from the 10th meeting mentioned the problem whether the baseline must be calculated and fixed before the project starts (ex-ante) or at the time of certification (ex-post). The statement is: "The ex-post calculation of baseline emission rates may only be used if proper justification is provided. Notwithstanding, the baseline emission rates shall also be calculated ex-ante and reported".

3.3.1 Small-scale Standardized Baselines

In order to simplify the procedures for small-scale CDM projects, the EB has proposed standardized baselines for some of the project categories shown in Chapter-1 (Table-1.2). For all small-scale projects the leakage calculation is not required, except if the project employs used equipment transferred from another site. A short description of the baseline methodologies is given below. Details with illustrative examples are provided in annexure-1.

I. Renewable energy projects

IA. Electricity generation by the user

In this category it is assumed that the electricity generation is a stand-alone application, not connected to a distribution grid or a mini-grid.

The energy baseline is the electricity consumption of the technology in use or what would have been used in the absence of the project activity. This may be

1) an estimate of the average annual individual consumption (in kWh) observed in closest grid electricity systems among rural grid-connected consumers belonging to the same category

Or 2) the estimated annual output of the installed renewable energy technology

The emission baseline is the energy baseline described above multiplied by 0.9kgCO_2 /kWh (default value).

IB. Mechanical energy for the user

The baseline is the estimated emissions due to serving the same load with a diesel generator i.e. fuel consumption saved times the emission coefficient for diesel. The diesel displaced is calculated as:

1) the power requirement x hours of operation/year x diesel emission factor from Table-3.2

or

2) diesel fuel consumption/hour x hours of operation x 3.2 kgCO_2 /kg diesel

IC. Thermal energy for the user

If fossil-fuelled technologies are replaced:

the baseline = the fuel consumption of the technologies that would have been used in the absence of the project activity x an emission coefficient (IPCC value) for the fossil fuel displaced.

If non-renewable sources of biomass is displaced:

the baseline = the non-renewable biomass consumption x an emission coefficient (IPCC value) for this biomass.

For renewable technologies replacing electricity:

the baseline = the electricity consumption x the relevant emission factor in Table-3.2.

It should be remarked that, although sink projects (except afforestation and reforestation) are not yet eligible under the CDM, avoided deforestation is eligible for small-scale CDM projects, but only in the category concerned with thermal use of energy.

ID. Renewable electricity generation for a grid

For a system in which all fossil-fuel fired generating units use fuel oil or diesel fuel: the baseline = the annual kWh generated by the renewable unit x an emission coefficient for a modern diesel generating unit of the relevant capacity operating at optimal load as given in Table-3.2.

For other systems, the baseline is the kWh produced by the renewable generating unit multiplied by an emission coefficient (measured in kg CO_2 /kWh) calculated in a transparent and conservative manner as the average of the "approximate operating margin" and the "build margin", where: .

The "approximate operating margin" is the weighted average emission (in kg CO_2/kWh) of all generating sources serving the system, excluding hydro, geothermal, wind, low-cost biomass, nuclear and solar generation. The "build margin" is the weighted average (in kg CO_2/kWh) of recent capacity additions, defined as the most recent 20% of plants built or the 5 most recent plants, whichever is greater. If the build margin data is not available, the weighted average emission (in kg CO_2/kWh) of the current generation mix will be used.

This category also covers landfill gas and other CH_4 gases from waste that is used for electricity generation

Table-3.2: Emission coefficients for small diesel generator

Mini grid kg CO_2 /kWh	24 h Service	4-6 h service	With storage
Load factors	25%	50%	100%
<15 kW	2.4	1.4	1.2
15-35 kW	1.9	1.3	1.1
35-135 kW	1.3	1	1
135-200 kW	0.9	0.8	0.8
>200 kW	0.8	0.8	0.8

II. Energy efficiency improvement projects

II A. Supply side energy efficiency improvements - transmission and distribution

New technologies or measures may be applied to existing systems or may be part of an expansion of the systems.

For a retrofit of an existing system, the energy baseline is the technical losses of energy calculated as either the measured performance of the existing equipment or using a performance standard.

For a new system the energy baseline is the technical losses of energy calculated using a performance standard for the equipment that would otherwise have been installed.

The emission baseline is the energy baseline multiplied by an emission coefficient as for category ID. For district heating systems use an IPCC default emission factor for the fossil fuel used by the system.

II B. Supply side energy efficiency improvements – generation

The technologies or measures may be applied to existing systems or be part of a new facility.

For a retrofit of an existing system, the energy baseline is calculated as the monitored performance of the existing generating unit.

For a new facility, the energy baseline is the technical losses calculated using a performance standard for the equipment that would otherwise have been installed.

The emission baseline is the energy baseline multiplied by an IPCC default emission coefficient for the fuel used by the generating unit.

II C. Demand-side energy efficiency programmes for specific technologies

The technologies may replace existing equipment or be installed at new sites.

If the energy displaced is a fossil fuel, the energy baseline is the existing fuel consumption or the amount of fuel that would be used by the technology that would have been implemented otherwise. Here the emission baseline is the energy baseline x an IPCC default emission factor.

If the energy displaced is electricity, the energy baseline is calculated as the number of devices x the power in W of the device x the average annual operating hours of the device/the technical loss in the grid. This energy baseline is multiplied by an emission coefficient as for category ID.

II D. Energy efficiency and fuel switching measures for industrial facilities

This category covers project activities aiming primarily at energy efficiency. A project activity that involves primarily fuel switching falls into category IIIB.

The technologies may replace existing equipment or be installed at a new facility.

The baseline calculation is the same as that in IIC.

II E. Energy efficiency and fuel switching measures for buildings

This category covers project activities aimed primarily at energy efficiency. A project activity that involves primarily fuel switching falls into category IIIB.

The baseline calculation is like for IIC.

III. Other project activities

III A. Agriculture

The Executive Board considers that more work is needed before proposing simplified baselines for this category.

III B. Switching fossil fuels

This category comprises fossil fuel switching in existing industrial, residential, commercial, institutional or electricity generation applications.

The emission baseline is the current emission of the facility.

III C. Emission reductions by low GHG emission vehicles

The energy baseline is the energy use per unit of service for the vehicle that would otherwise have been used x the average annual units of service per vehicle x the number of vehicles affected x the emission coefficient for the fuel used by the vehicle that would otherwise have been used.

If electricity is used by the vehicles, the associated emissions shall be estimated in the same way as in category ID.

III D. Methane recovery

This category covers landfill gas and other gases containing CH4 from waste that is only captured and flared. If CH4 is used for electricity or heat production, use the same way as in category IC or ID.

The emission baseline is the amount of methane that would be emitted to the atmosphere during the crediting period in the absence of the project activity.

III E. Methane avoidance

The Executive Board has requested the Meth Panel to develop simplified methodologies for this section.

3.4 DURATION OF THE PROJECT ACTIVITY/ CREDITING PERIOD

This section of PDDs (section C) should include the following information:

- . Duration of the project activity including the starting date and operational lifetime.
- . Choice of the crediting period.

According to the 'Modalities and Procedures for the CDM', there are two possibilities for the crediting period:

- A period of maximum 10 years
- A period of maximum 7 years, with the potential for renewal for two additional periods at most.

Credits for projects initiated after January 2000 and before the adoption of decision 17/CP.7 on 10 November 2001, and registered before 31 December 2005, may be claimed exceptionally prior to the registration. Certified emission reductions (CERs) obtained during the period from the year 2000 up to the beginning of the first commitment period can be used to assist in achieving compliance in the first commitment period.

The crediting period starts after project registration. In the 'CDM glossary'written by the EB, the starting date of a project activity has been defined as follows: "The starting date of a CDM project activity is the date at which the implementation or construction or real action of a project activity begins."

In many cases project participants would prefer a longer crediting period to the 10 year option without a renewal. However, there is a risk that the original baseline is not valid after the 7-year period. In this case it should be revalidated by a Designated Operational Entity (DOE). For revalidation, only an updating of the data used in setting the baseline is needed, since the baseline methodology should not be changed.

3.5 MONITORING METHODOLOGY AND PLAN

This section of PDDs (section D) should include the following information:

- Name and reference to the UNFCCC website of the approved methodology applied to the project activity.
- Justification of the choice of the methodology and why it is applicable to the project activity.
- Tables to be filled with information on to data to be monitored
- Name and contact information of person/entity determining the monitoring methodology.

The project participants must include a monitoring plan in the PDD. A detailed description of this plan must be included in this section of the PDD, including an identification of the data and its quality with regard to accuracy, comparability, completeness and validity.

The monitoring plan must include a justification of the choice of the methodology and why it is applicable to the project activity. The monitoring methodologies approved by the EB can be found in the database on the UNFCCC CDM website. A new monitoring methodology can be suggested to the EB in the same way as for baseline methodologies.

The Procedures and Modalities being formulated by the EB for small-scale CDM projects also includes simplified monitoring methodologies.

According to "Modalities and Procedures for the CDM", a monitoring plan must provide for:

- Collection and archiving of data necessary for calculating emissions within the project boundary
- Collection and archiving of data necessary for determining the baseline, as applicable
- Collection and archiving of data necessary for calculating leakages, where this needs to be considered
- Quality assurance and control procedures

Monitoring data required for verification and issuance are to be kept for two years after the end of the crediting period or the last issuance of CERs for this project activity, whichever occurs later.

3.6 CALCULATION OF GHG EMISSION BY SOURCES

This section of PDDs (section E) should include the information about calculation of GHG emission reductions by sources.

A way to proceed could be first to make a list of the GHG emission sources associated with the project and make a distinction among:

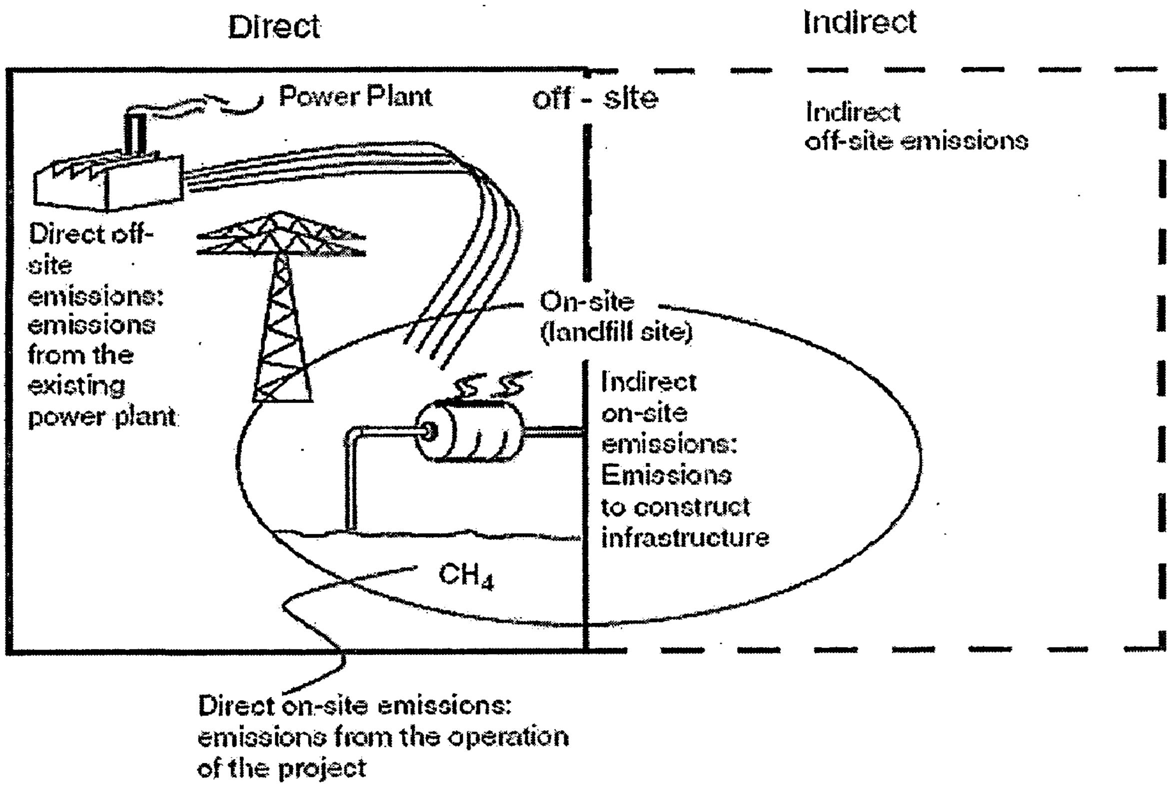
- Direct on-site emissions
- Direct off-site emissions
- Indirect on-site emissions
- Indirect off-site emissions

(the site is where the project activity is taking place)

Direct on-site emissions could be emissions from fuel combustion in the project.
Direct off-site emissions could be baseline emissions from heat/electricity which used to be delivered from the grid but which is going to be produced by the project. These old power plants are inside of the project boundary. Another example could be CH_4 emissions reduction from landfills due to a project where CH_4 is collected and used/burned.
Indirect on-site emissions from energy consumption, for example for the construction of a hydropower dam, power intake, tunnels, roads, pipelines, can be excluded since they are small compared to the emissions from the plant and difficult to measure.
Indirect off-site emissions from the production of the raw materials must be outside of the boundary, since they are not directly influenced by the project activity.
The next step is to conclude which of these emissions are inside the project boundary. The project boundary can include both on-site and off-site emissions. The project boundary encompasses all anthropogenic emissions under control of the project participants. The general rule is that emissions should not be taken into account unless they are directly controlled or influenced by the project. It is a good idea to draw a graph showing the main components of the project, the flow of energy and its boundary and outside connections. Indicate which components will be added, removed, or refurbished by the project.
Leakage is a measurable emission increase or decrease that is attributable to the project, but which is outside of the CDM project boundary or timeframe. Leakage calculations are required for small-scale CDM project activities except if renewable energy technology or energy-efficiency equipment is transferred from another activity. This exception was introduced in order to avoid cases in which an investor gained CERs just by exchanging old equipment with some new equipment at another site. Upstream emissions should be placed within the project boundary in cases where the project developer can significantly influence these emissions.

This section of the PDD must be for each gas and source, including descriptions of the formulae used to calculate the emission within the project boundaries both for the project activity and the baseline. The formula used for leakage calculation must also be described. Finally a table must be included with the values of the size of the emissions using the formulae mentioned.

Figure-3.1: Illustration of direct, indirect, on-site and off-site emissions from landfill gas power plant project



Source: CDM Information and Guidebook, Unep Reso Centre

3.6.1 Emission Factors

Unless better emission factors are available, the Revised 1996 IPCC Guidelines for National GHG Inventories should be used to calculate emissions.

A CDM project needs to reduce the emissions of carbon dioxide or one of five GHGs in Table-3.3: CO2, methane (CH4), nitrous oxide (N2O), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs) or sulphur hexafluoride (SF6). The default IPCC CO2 emission factors for the most common fuels are shown in Table-3.3. In Table 3.3 in the IPCC Guidelines mentioned above, these emission factors (plus some more rarely used fuels) are listed in the unit of tonnes of Carbon emitted per TJ fuel (t C/TJ). In order to convert them into t CO2 /TJ they are multiplied by 44/12 (the molecular weight of CO2 divided by the atomic weight of Carbon)

-Table-3.3: IPCC CO2 emission factors

Fuel	t CO2 /TJ
Natural gas	56.1
LPG	63.1
Gasoline	69.3
Jet Petroleum	71.5
Kerosene	71.9
Crude oil	73.3
Diesel 74.1	74.1
Fuel oil 77.4	77.4
Orimulsion 80.7	80.7
Coal	94.6
Petroleum coke	100.8
Lignite	101.2
Peat	106.0
Coke	108.2

3.6.2 Global Warming Potentials

In the emission calculation all results must be converted into CO2–equivalents (CO2–eq.). This is done by multiplying the emissions by the Global Warming Potential (GWP) in Table-3.4. If, for example, the emissions were 10 tonnes of CH4, the CO2-equivalent is 210 tonnes CO2-eq., which is 10 multiplied by 21. The GWPs are estimated by complex modelling of the chemical interaction in the atmosphere and will change over time as the knowledge about atmospheric chemistry improves. But new values must first be used after they have been published in an IPCC Assessment Report and a meeting of the Conference of the Parties (COP) under the UNFCCC has decided to use them.

Table-3.4: Global Warming Potentials

Species	Chemical Formula	100 years GWP
Methane	CH4	21
Nitrous oxide	N2O	310
Sulphur hexafluoride	SF6	23900
Perfluoromethane	CF4	6500
Perfluoroethane	C2F6	9200
Perfluorobutane	C4F10	7000
HFC-23	CHF3	11700
HFC-32	CH2F2	650
HFC-43-10	C5H2F10	1300
HFC-125	C2HF5	2800
HFC-134a	CH2FCF3	1300
HFC-143a	C2H3F3	3800
HFC-152a	C2H4F2	140
HFC-227ea	C3HF7	2900
HFC-236fa	C3H2F6	6300
HFC-245ca	C3H3F5	560

3.7 ENVIRONMENTAL IMPACTS

The objective of any CDM project should be to provide environmental and social benefits as well as reduce GHG emissions. However, if the host country requires an Environmental Impact Assessment (EIA), or stakeholder input shows that there are local environmental or social concerns about the initiative, a CDM project should be evaluated using the highest international environmental and social assessment procedures and standards. The conclusions from these assessments must be included in section F in the PDD and the assessments should be attached.

3.8 STAKEHOLDER COMMENTS

The DOE doing the validation must make the project design document for the CDM project publicly available. NGOs and other stakeholders have a 30-day period to comment on the PDD and thereafter the DOE must describe how comments by stakeholders have been invited and compiled; a summary of the comments received; and a report on how due account was taken of any comments received.

These comments therefore form an official input as part of the prescribed validation and registration process, creating an unknown factor in the project development cycle that investors cannot ignore. In order to get a feeling of how the NGO community is mobilising in this area, it is recommended that readers view "CDM Watch", created by a number of NGOs. Some stakeholders will have problems in making their comments. Often the PDDs will be posted on the Internet and stakeholders in rural projects often have no access to the Internet. Likewise there is no requirement that documents be made available in a language familiar to stakeholders.

3.9 ANNEX 1: CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

According to the CDM Glossary, project participants are Parties or private and/ or public entities (authorized by a Party to participate) that take decisions on the allocation of CERs from the project activity under consideration.

3.10 ANNEX 2: INFORMATION REGARDING PUBLIC FUNDING

If public funding from Annex I Parties is involved, this annex should contain information on the sources of public funding for the project activity, including an affirmation that such funding does not result in a diversion of official development assistance and is separate from and is not counted towards the financial obligation of those Parties.

CHAPTER-4

FINANCING AND MARKETTING OF CDM PROJECTS

4.1 CDM PROJECT VIABILITY

CDM projects produce both conventional project output and carbon benefits (CERs). The value of carbon benefits and its impact on project viability are influenced by several factors such as the amount of CERs generated by the project, the price of CER and the transaction costs involved in securing CERs. These factors are briefly explained below:

Quantity of CERs: The amount of CERs generated by the project depends on the greenhouse gas displaced by the project and the crediting period selected. Renewable energy and energy efficiency projects displace carbon intensive electricity and/or heat generation. Grid-based or off-grid projects that displace more carbon intensive coal and diesel fuels generate more CERs than those that displace natural gas. Projects that capture methane and greenhouse gases other than CO2 produce more CERs since the global warming potential (GWP) of methane and other gases are several times higher than that of carbon dioxide.

The Marrakech accord stipulates two crediting period options: 7 years with twice the option of renewal (totaling 21 years) or, 10 years without renewal.

Price of CERs: The price of CERs is determined in the carbon market. At present, the carbon market is a 'loose collection of diverse transactions' where emission reductions are exchanged. There are three main markets where greenhouse gas emission reductions are traded: project based or "baseline and credit" system; allowance market or "cap and trade" system, and; voluntary market.

At present there is no single CER price but differentiated according to risks, technology type and social development components. The current PCF CER rate ranges from US$3 to 4 per ton of CO2; under the C-ERUPT program, it revolves around US$ 4 to 4.5 per ton of CO2.

Transaction Costs: Transaction costs are those that arise from initiating and completing transactions to secure CERs. These consist of pre-operational costs (or upfront costs), implementation costs (i.e. costs spread out over the entire crediting period), and trading costs (Table-4.1).

Several studies show that the transaction cost per ton of CO2 for large projects is very small or even negligible while that for small-scale projects is quite significant.

Given this, it is obvious that investors would prefer large-scale projects. Fast-tracking small-scale projects (simplifying the procedures and standardizing the information and reporting requirements) not only reduces transaction costs but also improves project financial viability. According to Ecosecurities (2002), fast-tracked procedures lead up to around 67% reduction in transaction costs.

Table-4.1 CDM Transaction Costs

	Transaction Cost Component	**Description**
Pre-operational Phase (upfront costs)	Search Costs	Costs incurred by investors and hosts as they seek out partners for mutually advantageous projects
	Negotiation Costs	Includes those costs incurred in the preparation of the Project Design Document that also documents assignment and scheduling of benefits over the project time period. It also includes expenses in organizing public consultation with key stakeholders.
	Baseline determination	Development of a baseline
	Approval costs	Costs of authorization from host country
	Validation Costs	Costs incurred in reviewing and revising the Project Design Document by operational entity
	Review Costs	Costs of reviewing a validation document
	Registration	Costs Registration by UNFCCC Executive Board/JI Supervisory Committee
Operational Phase	Monitoring Costs	Costs to collect data
	Verification Costs	Costs to hire an operational entity and to report to the UNFCCC Executive Board/Supervisory Committee
	Review Costs	Costs of reviewing a verification
	Certification Costs	Includes costs in the issuance of Certified Emission Reductions (CERs for CDM) and Emission Reduction Units (ERUs for JI) by UNFCCC Executive Board
	Enforcement costs	Includes administrative and legal costs incurred in enforcing transaction agreements
Trading	Transfer Costs	Brokerage costs
	Registration Costs	Costs to hold an account in national registry

Source: Michaelowa, A., Stronzik, M., Eckerman, F., and Hunt, Alistair, 2003..

Impact of CERs on Project Viability: The net financial gain derived from the sale of CERs is the difference between the project CER value and the transaction costs. There are three elements that influence the net impact of CERs on project profitability: value of CERs (low CER value implies low net benefits), overall transaction costs (high transaction costs yield low net benefits), and up-front transaction costs (high upfront payments could also result in low benefits). Project developers generally expect up-front transaction costs within the range of 5 to 7% of the net present value of the revenue or total transaction costs around 10 to 12% of the net present value of revenue (Ecosecurities, 2002). A positive net financial gain means that CER revenues improve the financial viability of the project. Table-4.2 shows the impact of CERs on IRRs in selected projects.

Table-4.2: Impact of CERs on project IRR

Country	Project	IRR without carbon finance (%)	IRR with carbon finance (%)	Change in IRR (%)
Costa Rica	wind power	9.7	10.6	0.9
Jamaica	wind power	17.0	18.0	1.0
Morocco	wind power	12.7	14.0	1.3
Chile	Hydro	9.2	10.4	1.2
Costa Rica	Hydro	7.1	9.7	2.6
Guyana	bagasse	7.2	7.7	0.5
Brazil	biomass	8.3	13.5	5.2
India	solid waste	13.8	18.7	5.0

Source: PCF Annual Report 2001

The effect of CER cash flow on project IRRs vary by project type. The impact of CERs on wind power project IRR is relatively small (few percentage points increase) while it is substantially important for fugitive methane capture projects. More CERs are generated by methane capture projects since the global warming potential of methane is 21 times higher than carbon dioxide. This makes methane capture projects relatively attractive to CDM project developers. In fact, for the first 45 projects submitted to the CDM Executive Board for methodology review, 27% (12 projects) are methane gas capture projects.

4.2 SECURING PROJECT FUNDS

4.2.1 CER Generation and Trading

Governments and private companies from non-Annex 1 parties are the main buyers of CERs. CERs are developed and exchanged under three main different models:

Unilateral model: the host country develops and invests in a project, and sells or banks CERs. The project developer bears all risks and benefits related to the preparation and sale of CERs.

Bilateral model: this involves partnership between a project developer and Annex 1 country. The objective of the partnership is for the Annex 1 country to receive the CERs realized from the project through emission reduction purchase agreement (ERPA) or as a result of some other financial consideration.

Multi-lateral model: this is considered as a variant of the bilateral model. CERs are sold to a fund, which manages a portfolio of projects. The fund spreads the risk of investment while the investors spread their risks by investing in several different funds.

The carbon finances at the World Bank (Prototype Carbon Fund, Community Development Fund, and BioCarbon Fund) are examples of multi-lateral funds using the World Bank as fund manager. The Dutch Government adopts several means of procuring emission reduction credits, through multi-lateral organizations such as World Bank and International Finace Corporation, through banks (e.g. Rabo bank), through bilateral contracts and via its own tender (C-ERUPT). Japan, Germany and Denmark use banks and other financial institutions in managing their CDM funds. More recently, Canada and several European countries have initiated bilateral transactions with several developing and Eastern European countries.

4.2.2 Sources of Project Funds

CDM projects require upfront investments that are normally obtained from different sources such as loans, equity, grants, and upfront payments for emission reductions.

- Loans or debts refer to funds lent to CDM project owners by financiers. Debt can be obtained through public markets (bonds) or private placements (bank loans and institutional debt).
- Equity refers to funds funneled to the CDM project by company shareholders. Equity may be sourced from internal sources (sponsors) or external investors

(public or private markets). The return on equity is obtained either from dividends or from sale of shares.

- Grants are funds provided by institutions and governments to CDM project owners and developers who contribute to donors' objectives. Grants need not be repaid and oftentimes, cover only a percentage of project costs.
- Upfront payment for CER purchase. The carbon purchase agreement often stipulates payment on agreed price upon delivery of CERs but CER buyers sometimes provide upfront payment upon purchase. For example, the PCF provides upfront payment up to 25% of the total CER value.

However, to compensate for increased risk, upfront payments are discounted.

Like conventional projects, financing CDM projects can be arranged either through corporate or project financing. These are described as follows:

- In project financing, a project company is formed and investments are viewed as assets of the company. Investment funds are sourced either from equity or debt. Assets and cash flow secure debts. Creditors do not have recourse to the other resources of sponsors.
- Under corporate financing, new projects are undertaken as extension of assets of the existing company. Capital investments and borrowing are not placed under the project account. Loans are considered as company debts and lenders have full recourse to all the assets and revenues of the company over and above those generated in the new project.

Additional project revenues (i.e. CER) could be used to service debts and leverage debt financing. Guest et al (2003) presents that the carbon cash flow can help increase debt carrying capacity: The carbon revenues could help increase debt leverage of project by increasing the debt service coverage ratio (DSCR) levels of the project. In addition to improving debt capacity, there are other options to debt service through the carbon cash flow. These include: pre-paying debt based on Forward Emission Reduction Purchase Agreements (ERPAs); depositing carbon cash flow directly with banks for credit against debt service thereby lowering liability on electricity cash flow; and using ERPAs and/or forward carbon sales as collateral for loans (this is the case for Plantar project in Brazil where the CER purchase agreement with the PCF was used as collateral for commercial bank financing).

4.3 RISK MANAGEMENT

CDM projects face two types of risks: conventional project risks and CDM-related risks. Conventional project risks relate to uncertainties in project performance and in the market of project output while CDM-specific risks refer to uncertainties in the Kyoto process and its implementation as well as the market performance of carbon assets.

Project risks may be broadly classified into i) construction risks (referring to time and cost overrun), and ii) operational risks (involving technology performance, fuel, or product supply, market, operation, political, legal, environmental, and financial factors). Though these risks are generic to projects, these relate to project performance, which affect its ability to deliver the expected quantity of CERs.

On the other hand, CDM-related risks contain following risk categories:

Policy risks: this includes risk that the Kyoto Protocol will not be ratified; risk that the host country will not comply with its obligations; and risk that specific baselines and procedures used in the project will not be approved.

Market risk: CER pricing is highly speculative and that the development of the CER market and the evolution of CER prices are highly unpredictable.

Risk management principles apply to both categories of project risks, namely:

- allocation of risks to contracting parties who best understand the risks, and
- transfer of risks to a third party who uses financial tools.

There are several financial tools for risk management; these include hedging, guarantees and insurance products. In financial hedging, the derivative markets are used to fix future prices of commodities, currencies and interest rates. Financial derivatives market can also be used for emission commodities. These include: call and put options, collars, swaps and forward contracts. With insurance, a third party is paid to bear a particular risk. Insurance is often used to mitigate political risks and natural hazards.

A number of international agencies provide political risk insurance and guarantees. The European Investment Fund, for example, offers guarantees on debt financing to infrastructure projects including those in the energy sector. The International Bank for Reconstruction and Development (IBRD) likewise provides guarantees against interest rate conversions or swaps; interest rate caps and collars, currency conversions or swaps and commodity swaps. Several other risk mitigation organizations provide or broker mitigation products in the SO2, NOX emission reduction markets.

The PCF assumes CDM-specific risks and assigns project equity sponsors and creditors to bear project risks. In managing the Kyoto risk, the PCF i) seeks commitment from host countries for Kyoto Protocol ratification and compliance, and for the transfer of CERs; ii) shares this risk with project sponsors (in the case of Chile for example, PCF commits to a higher CER price once the Government ratifies the Kyoto Protocol and provides a letter of approval to PCF); and in some cases, requires the Kyoto ratification as a requirement in the carbon purchase agreements. Exposure to baseline risks is managed by commissioning a rigorous baseline study, monitoring plan and third party validation. For market risks, the PCF assumes market risks and agrees to pay the contract price regardless of the actual market price at the time of delivery.

4.4 DEMAND AND SUPPLY OF CERs

The Kyoto Protocol requires industrialized (Annex 1) countries (Table-4.3) to stabilize their GHG emissions to an average of 5.2% below their 1990 emissions over the period 2008-2012. The numbers in Table-4.3 show that many Western industrialized countries have net positive emissions in 2000 with respect to their Kyoto emission targets. Recent reports indicate that greenhouse gas emissions in 2002 and 2003 have continued to rise in many of these countries such as Australia, Austria, Finland, Germany, Japan, Norway, and the United Kingdom. Projections for 2010 show that the emissions gap will increase further in most of these countries even with full implementation of their current policy measures (Table-4.3). Most of the Eastern European countries however have their emissions in 2000 below their Kyoto targets, and as also shown in Table-4.3, their present positions could be maintained until 2010 with the current policies to mitigate greenhouse gas emissions.

Several options exist for many Annex 1 countries to meet this legally binding obligation. These include domestic mitigation measures, development of carbon sinks, trade of excess credits (hot air) from economies in transition, and trade of credits from CDM (CERs) and JI projects (ERUs). A number of EU states have disclosed to purchase emissions reductions from JI and CDM projects. For example the Netherlands government has planned to purchase annual emissions reduction of around 12 MMTCO2e, Italy at around 11 MMTCO2e, and Austria, Belgium, Denmark and Ireland combined at around 10 MMTCO2e during the period 2008-

2012. As shown in Table-4.4, the projected emissions reductions supply is estimated to be between 1177 and 2064 MMTCO2e per year. The CER supply could range from 55 to 183 MMTCO2e. As of early 2004, however, there are only 82 CDM projects that have reached Project Design Documentation stage, which could yield an accumulated CER supply of 23.4 million in 2007.

Table-4.3: GHG Emissions of Annex-1 Countries in 2000 and 2010

Country	Emissions reduction target under the Kyoto Protocol (% of 1990 emissions)	Emissions in 2000 (actual levels) MMTCO2e	Emissions in 2000 (% of 1990 emissions)	Projected Emissions in 2010 (% of 1990 emissions)
Australia	+8	501	+18	+16
Austria	-13*	80	+3	+12
Belgium	-7.5*	152	+7	+16
Bulgaria	-8	78	-51	-42
Canada	-6	726	+20	+19
Croatia	-5	22 (1995)	-30	-
Czech Republic	-8	148	-23	-32
Denmark	-21*	69	-1	+15
Estonia	-8	20	-55	-69
Finland	0*	74	-4	+17
France	0*	550	-2	+6
Germany	-21*	991	-19	-32
Greece	+25*	130	+24	+36
Hungary	-6	84	-17	
Iceland	+10	3	+7	-2
Ireland	13*	67	+25	+28
Italy	-6.5*	547	+5	+11
Japan	-6	1386	+11	+7
Latvia	-8	11	-64	
Liechtenstein	-8	0.218 (1999)	0	+2
Lithuania	-8	24 (1998)	-54	
Luxembourg	-28*	5.971	-56	
Monaco	-8	133	+33	
Netherlands	-6*	216.916	+3	+19
New Zealand	0	76.956	+5	+38
Norway	+1	55.263	+6	+22
Poland	-6	386.187	-32	
Portugal	27*	84.700	+30	+54
Romania	-8	164.026 (1994)	-38	-28
Russian Federation	0	1.965.346	-35	-20
Slovakia	-8	49.165	-33	-27
Spain	15*	385.987	+35	+48
Sweden	4*	69.356	-2	+1
Switzerland	-8	52.743	-1	-7.2

Ukraine	0	454.934	-51	
UK	-12.5*	649.106	-13	-15
USA	-7	7.001.225	+14	+16
Total		17.281.439		

Source: emissions data in 2000, HYPERLINK "http://ghg.unfccc.int" http://ghg.unfccc.int; emissions data in 2010, Annex 1 countries Third National Communications, http://unfccc.int.
Note: The numbers in parenthesis show different years. Emissions projections are based on 'with measures' scenario, and reference economic growth.
** According to burden sharing agreement, average of EU 15 is –8%.*

The projected demand and supply balance shows that there will be a net surplus of emissions reductions in 2010, which ranges from around 366 MMTCO2e to 1873 MMTCO2e. The demand of CERs is affected by several factors such as the growth of emissions in Annex 1 countries, abatement costs in developed countries, the markets of "hot air" and the JI market. The CER demand could be high or low, depending on the development of the above determining factors.

Table-4.4: Supply and Demand Balance in Kyoto First Period Commitments without US: Limiting Scenarios

MMTCO2e/year average	**Low Surplus Scenario (High Demand, low supply)**		**High Surplus Scenario (Low Demand, high supply)**	
	% change 2000-2010	*MMTCO2e/ year*	*% change 2000-2010*	*MMTCO2e/ year*
Demand		**811**		**191**
EU-15	7	440	-3	110
Japan	10	213	-3	62
Canada	15	224	0	136
Other GHGs		44		-7
Managed Forests		-110		-110
Supply		**1177**		**2064**
Russia	20	389	0	719
Ukraine	20	246	0	319
Accession 10	25	165	5	275
Other EIT	25	88	0	132
Other GHGs		88		290
Managed forests		147		147
CDM (equiv. annual)		55		183
Surplus		**366**		**1873**

Source: Grubb et al. 2003.

Note: data were converted from MMTC/year.

4.5 CER MARKET DEVELOPMENT

4.5.1 Carbon Markets

The CER market can be broadly classified as follows:

- Project-based or baseline and credit system. Emission reductions are created and traded through a given project or activity. CDM and JI are examples of the project-based system where CERs and ERUs are generated respectively.
- Allowance market or cap and trade system. Emission allowances are defined by regulations at the international, national, regional or firm level. Examples of allowance market include the Emissions Trading under the Kyoto Protocol (global), EU ETS (regional), the UK and the Danish trading systems (national), and BP and Shell internal trading (firm).

4.5.2 Current buyers and CER transactions

Project-based transactions (CDM and JI) dominate the global trade of greenhouse gas emission reductions. It represented 85% of the total transaction volume in 2002, and 97% between 1996 and 2002 (PCF Plus, 2002). The total carbon market volume traded in 2001 was about 13 MMTCO2e, increasing to 29 MMTCO2e in 2002, and reaching to more than 70 MMTCO2e in the first 10 months of 2003 (PCF, 2003). Point Carbon (2004) projected that the total volume will reach 100 MMTCO2e in 2004.

The World Bank's PCF and the Dutch Government's C-ERUPT tender are the current main buyers of CERs through direct purchase transactions. As of 2003, the PCF has signed 7 emission reductions purchase agreements (ERPAs) with total emissions reductions of 12.19 MMTCO2e. Also, PCF has 144 projects under preparation and received 420 project idea notes. The C-ERUPT tender, on the other hand, approved 18 projects in 2003 aimed to generate emissions reductions of 16.7 MMTCO2e. A number of PCF projects have been operational since 2002. CDM portfolios were also launched by Austria, Denmark, Finland and Sweden. The Austrian government opened a tender for CDM projects in December 2003. Denmark is cooperating with Thai industries and will select 5 projects for actual CDM implementation. The Finnish Government launched a tender for small-scale projects and is currently engaged with preliminary discussions with 7 CDM project sponsors. Sweden launched a tender in

2002 and elected 5 projects in India, Brazil and South Africa. Most recently, Belgium announced its plan to purchase emissions reductions of around 2.46 MMTCO2e annually in the period 2008-2012.

CER procurement funds are growing and expanding. As shown in Table-4.5, three new public-private partnership funds have been recently launched by the World Bank: the Community Development Carbon Fund, the Bio-Carbon Fund and the Italian Carbon Fund. Public-private partnership funds to purchase CERs were also established by the European Investment Bank, Japanese Banks, Germany's KfW and Ecosecurities-Standard Bank of London (Danish CDM Facility). In addition to the Government of the Netherlands, several European governments have launched CDM funds. These governments have used several vehicles in CER procurement such as government-own tenders through banks and multilateral institutions. Bilateral transactions are also emerging. Several European governments and the government of Canada have signed MOUs with several Latin American and Asian countries for the development of projects and supply of CERs.

CERs purchased through public-private partnership and government funds are mainly used for Kyoto compliance. Private funds are also being established to secure CERs for purposes other than compliance. Mitsubishi Corporation of Japan recently purchased emission rights from a Chilean Hydropower project for trading purposes. More recently, Cambria Energy, Investic Bank and Less carbon launched ICECAP, a vehicle to purchase CERs for large industrial emitters and Annex 1 governments. Mitsubishi Securities Company and Mizuh Securities Company are also planning to be involved in the purchase of carbon emissions certificates to cater to the needs of their business clients. Aside from trading, institutions interested in becoming carbon neutral with their activities could be another buyer of CERs. The Dutch Development Finance Company, for example, have announced their intention to compensate carbon dioxide emissions from their activities in developing countries and that it plans to purchase CERs from projects the company finances.

Table-4.5: CER Procurement Funds

Public-Private Partnerships	Government Funds	Private Funds
Multilateral Institutions **The World Bank** • Prototype Carbon Fund (US$180 million) • Community Development Carbon Fund (US$ 100 million) • World Bank Bio-Carbon Fund (US$ 100 million) • Italian Carbon Fund (US$15 million) • Spanish Carbon Fund (under discussion) **European Investment Bank** •Proposed Carbon Investment Trust **Other Financial Institutions Japan** *Japan Bank for International Cooperation (JBIC) and Development Bank of Japan* • Joint Carbon Fund (10 billion yen) **Germany** *KfW* German Carbon Fund (€ 50 million) **Denmark** *Ecosecurities and Standard Bank of London* • Denmark Carbon Facility (DKK 59 million)	**Own Tender** • Denmark CDM Program • Dutch Government C-ERUPT Program • Finnish CDM/JI Pilot Program (€ 20 million) • Sweden International Climate Investment Program – CDM • Austria JI/CDM Procurement Program • Belgium CDM/JI Program **Through Commercial/ Development Banks** • Rabo Bank (Dutch Government) **Through Multilateral Institutions** • World Bank (The Netherlands Clean Development Facility - € 70 million) • IFC (IFC-Netherlands Carbon Facility - € 44 million) **Through Bilateral Transactions (signed MOUs)** • Austria: discussions with China • Canada: Costa Rica, Colombia, Chile, Nicaragua, Tunisia, South Korea • Denmark: Malaysia; discussions with China, South Africa • Finland: China, Costa Rica, El Salvador, Nicaragua, India • France: Colombia and Morocco • Italy: Algeria, China, Cuba, Cyprus, Egypt, El Salvador, Israel, Morocco • Netherlands: Colombia, Costa Rica, El Salvador, Panama, Uruguay, Bolivia, Nicaragua, Guatemala, Honduras. Under negotiation: Indonesia, Philippines).	**For Trading** • ICECAP (Cumbria Energy, • Investec Bank and Less Carbon) • Mitsubishi Corporation (purchased emission rights from Hidroelectrica Guardia Vieja, SA) • Mitsubishi Securities Co. • Mizuho Securities Co. • Voluntary use (carbon dioxide neutral) • Dutch Development Finance Company

4.6 CER PRICES

The fragmented nature of the global carbon market generates differentiated prices for emissions reductions as shown in Table-4.6. Allowance markets generate high emission reduction prices since the delivery risks are believed to be minimal. Though JI and CDM are both project-based, PCF pays higher prices for ERUs since JI are supported by Host Country Agreements and Assigned Amount Units, which reduces

PCF's exposure to risks. ERUPT however in its January 2003 tender for JI projects have specified a price range similar to C-ERUPT tender for CDM projects.

The current price spread of CERs is US$ 3 – 6 per TCO2e (Table-4.6). PCF's price average is relatively lower than that of C-ERUPT's. The Finnish Government's offer for CER's from its pilot programme is lower than C-ERUPT's price range since it focuses on small-scale projects which have higher transaction costs and delivery risks. Among the CDM projects being contracted by PCF, a price premium of US$ 0.5 per TCO2e has been offered to the Colombia Jepirachi Wind Farm sponsors for the delivery of activities that improve the social conditions of the local indigenous population that hosts the project.

The CER is being differentiated from other emission reduction instruments due to its high delivery risks. Moreover, there is no standardized CER price. Instead CERs are differentiated according to its related risks, sustainable development component, and technology type. The CER price differentiation could evolve into the following categories: i) CERs from projects that fulfill the WWF Gold Standard, ii) CERs from projects with community development features, iii) CERs from standard projects, and iv) long-term and temporary CERs from forestry projects (Michaelowa, A., CDM Monitor, March 11, 2004).

With the entry of CERs in the EU allowance market under the linking Directive, CER price could rise to EU allowance price. The EU ETS could potentially set the limit of CER prices which is equal to EU allowance price minus a risk premium.

Table-4.6: Carbon Emission Reduction Prices (per TCO2e)

Project-Based		
Clean Development Mechanism	**Joint Implementation**	**Allowance Markets**
PCF[1] • US$3.0-3.5 • premium of US$0.5 per ton of CO2e for projects with developmental components (Colombia Wind Farm) **CERUPT**[2] **(maximum prices)** • renewable energy – €5.5 • biomass energy - €4.4 • energy efficiency - €4.4 • fuel switch and methane - €3.3 • average price - €4.73 **Finnish Government4** • small-scale - €2.47-3.2	**PCF**[5] • US$ 3.5-4.0 **ERUPT**[6] • First tender average price - €8.46 (closed in April 2001) • Second tender average price - €4.78 (closed in March 2002) • Third tender - expected price range - €3.0-5.07 (closed in January 2003) **Denmark-Romania JI**[8] • estimated price range €5.40-8.10	**Regional** • EU-ETS8 € 5.0-7.0 (indicative price); € 13.059 (forward price in Jan 2004); € 7.1710 (forward price in Apr 2004) **National** • UK-ETS9 – Bid price £1.75, offer price £2.25 **Firm** • BP Emissions Trading Scheme10 (Scheme discontinued in 2001) average in 2000 – US$7.6 average in 2001 – US$39.63

[1]*PCF Annual Report 2002; 2C-ERUPT Tender Document 2002; 3Carbon Market Europe (March 21 2003);*

[4]http://global.finland.fi; *5PCF Annual Report 2002; 6Environmental Finance (February 2003); 7GHG Market Trends 2/2003; Carbon Market Europe (March 7, 2003); 8Carbon Market Europe (May 2 2003);*

[9]*Carbon Market Europe (August 15 2003);* [10]*ww.bp.com/files/15/Climate_Change_2001_performance_1541.pdf*

CHAPTER-5

CLEAN DEVELOPMENT RESOURCES OF NEPAL

This chapter describes the country profile of Nepal and energy consumption pattern in various energy end use sectors. The inventory of national GHG emissions is also presented in this chapter.

5.1 COUNTRY BACKGROUND

5.1.1 Geography

Nepal is a landlocked and predominantly mountainous country sandwiched between India on three sides – East, West, and South, and the People's Republic of China to the North. The country spans a total area of 147,181 sq. km. with tropical plains in the South and the Himalayas in the North within a mean width of 193 km. This tremendous variation in altitude within a relatively short distance is what gives the country its varied ecological zones and the range of biological and cultural habitats it enjoys.

Nepal is endowed with rich natural and cultural diversity. The mountains, hills and the Terai are three distinct ecological regions running from the North to the South respectively and form three parallel belts spanning the length of the country. The mountainous region consists of a large number of magnificent snow covered mountains including Mount Everest (8848 meters) and covers about one third (35%) of the total land area of which only 2% is suitable for cultivation. This region is the most sparsely populated region because of its geographic and climatic conditions. The hills region, on the other hand, comprises of several attractive peaks, fertile valleys and basins including the densely populated Kathmandu and Pokhara valleys. This region makes up 42% of the total land area, out of which about one-tenth is suitable for cultivation. About 46% of the total population resides in this region. The Terai region accommodates 47% of the total population and comprises 23% of the total land area, which includes fertile land and dense forests (CBS, 2001, Page i – ii).

For administrative purposes, Nepal is divided into five development regions: Eastern, Central, Mid-Western, Western and Far-Western. The Mid and Far Western areas are most backward in overall development. These zones are further divided into a total of 75 districts (16 in the Mountain region, 39 in Hill region and 20 in the Terai region). District distribution Development Region- wise is: 16 in the Eastern, 19 in the Central; 16 in the Western, 15 in the Mid-western and the remaining 9 in the Far-Western regions. Each district constitutes of, on an average, 60-70 village development committees (VDCs). On average each VDC includes around 500 households. Government administration is carried out through the 3,914 VDCs and 58 Municipalities in all 75 districts.

Such a geographical setting of the country brings both complexity and opportunity for natural resource management and sustainable development.

5.1.2 Natural Resources

The country's topography is rugged with over three-quarters of the total area made up of mountains, hills and valleys. The distribution of land according to land use is illustrated in the table below:

Table 5.1: Land Use Pattern of Nepal (1999)

Land Use Type	Area ('000 ha)	Share (%)
Forest Land	4,269	29
Cultivated Land	2,968	20
Grass Land	1,745	12
Non-cultivated Land	998	7
Shrub land/degraded forest	1,559	11
Other Land Uses	3,179	22
TOTAL	**14,718**	**100**

Source: DOA (1999), FSD (1999), ICIMOD (2000) in UNEP et al. 2001, P. 17

Forestland remains the largest category in terms of land use; however, it has been subject to immense pressure. Forest areas have declined from 45% in 1966 to 37% in 1986 whereas shrub land has doubled from 5% in 1980 to 10.6% in the mid 1990s. This corresponds to the annual estimated deforestation rate of 1.7% (DFRS 1999 in UNEP et al 2001, P. 18). Agricultural land, the second largest category, however, has declined in terms of per capita from 0.16 ha in 1980 to 0.13 ha in 1999 (CBS 1999 in UNEP et al, 2001, P. 17). The Nepali economy is dualistic with a relatively modern non-agricultural sector and a largely subsistence-based agricultural sector.

Water is Nepal's major natural resource. There are about 6,000 rivers and rivulets in the country and the annual mean flow for the snow-fed major rivers is estimated to be 4,930 m^3/sec (UNEP et. al., 2001, P.17). The hydroelectric power potential is estimated at 83,000 megawatts, of which about 50 percent could be economically harnessed. However, only a little more than 1.5 percent of this economically viable potential has been exploited so far. There is also a growing pressure on water resources due to the population growth, expansion of irrigation systems, agricultural production, urbanization and industrial expansion. The surface water and groundwater sources, especially in urban areas, have also deteriorated. A combination of fossil fuel combustion, deforestation, and change in land use patterns account for the GHG effect in Nepal. According to the World Bank (2003, P. 23) estimate in 1999, the annual per capita CO_2 emissions in Nepal is 0.1 tons.

5.1.3 Population

In 2001, the population of Nepal was calculated to be around 24 million, of which 48.7% were women. The population density stands at an estimated 165 persons per square km. Nepal is probably one of the very few countries in the world where the life expectancy of men (60 years) is higher than that of women (59 years) as presented by The World Bank (2003, P.15 & 29). A population growth rate of 2.3 percent per annum during 1980 – 2001 and the expected growth rate of around 2% until 2015 (World Bank, 2003, P. 39) is putting Nepal's environmental resources under tremendous pressure. The three towns of the Kathmandu Valley, namely Kathmandu, Patan and Bhaktapur, account for almost 40 percent of the entire urban population in the country. Nepal's population is relatively young, with 46 percent being under the age of 16.

5.1.4 Economy

Nepal is one of the least developed countries, with 38 percent of the population still below the poverty line at the end of the Ninth Five Year Plan in 2002. GoN's Tenth Five Year Plan (2002-2007) adopts poverty alleviation as its central focus with special emphasis on the development of politically, geographically and socially backward areas, and upliftment of indigenous communities, ethnic groups, and oppressed sections of society. The Tenth Plan's sectoral emphasis is on Agriculture and Forests, Water Resources, Human Resource and Social Development, Industrialization, Tourism Development and International Trade, and Physical Infrastructure Development.

5.1.5 Human Development

Nepal belongs to the category of low human development countries. Nepal is ranked 143rd in the 2003 Human Development Report with the human development index (HDI) value of 0.499 and per capita Gross Domestic Product (GDP) of Purchasing Power Parity (PPP) US$ 1,310 (Human Development Report, 2003 in http://www.undp.org.np). Nepal ranks 129th in life expectancy at birth with 59.1 years and ranks 112th in combined primary, secondary and tertiary gross enrollment ratio of 63.7%. As reflected in Nepal's Human Development Report for 2001 (Page 149), the level of human development attainment varies widely across regions: human development in Kathmandu is, for example, four times that of Mugu, the most deprived district. As presented in the HDR report, Nepal's HDI has been increasing from 0.287 in 1975, 0.368 in 1985 and to 0.499 in 2001.

Nepal's struggle to reduce poverty can also be envisaged in the world scenario. Nepal stands in the 70th position among 94 developing countries with the Human Poverty Index (HPI-1) value of 41.9%. Similarly, with a value of only 0.479, Nepal ranks 119th in the Gender-related Development Index (GDI).

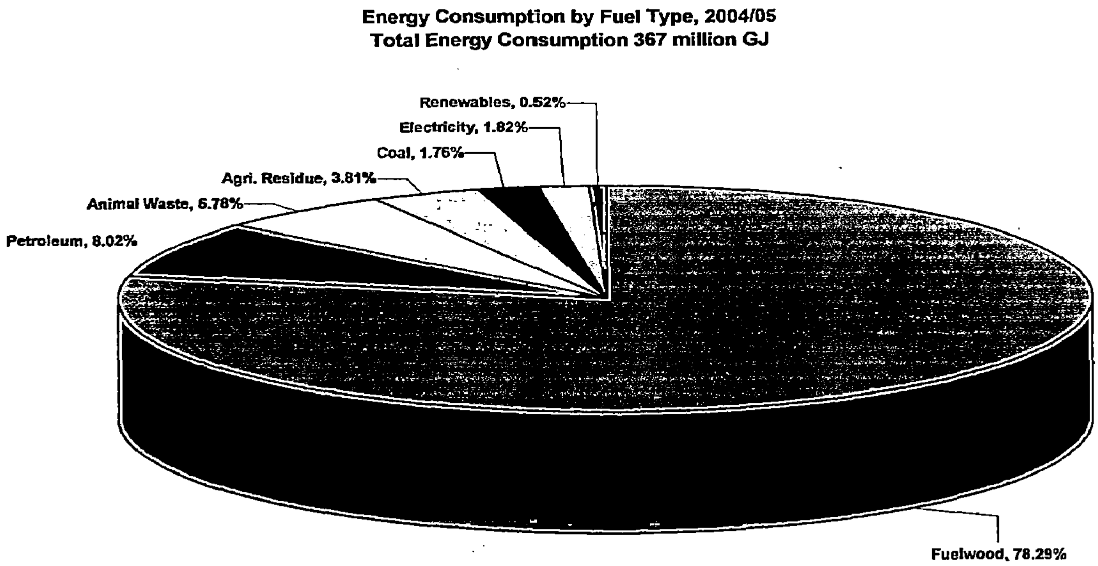
5.2 ENERGY SECTOR REVIEW

5.2.1 National Energy Supply and Demand Situation

The total energy consumption in Nepal was 8.62 million toe in 2005, which translates to per capita annual energy consumption of about 15 Giga Joule (GJ), ranks among the lowest of the world (WECS, Energy Sector Synopsis Report, 2006).

The energy mix is lopsided in Nepal, with biomass (fuel wood, agricultural residue and animal dung) being the main energy providers, supplying an overall 88% of the total energy consumed. Figures below illustrate the share of different forms of energy in the total supply and the sectoral consumption (WECS, Energy Sector Synopsis Report, 2006).

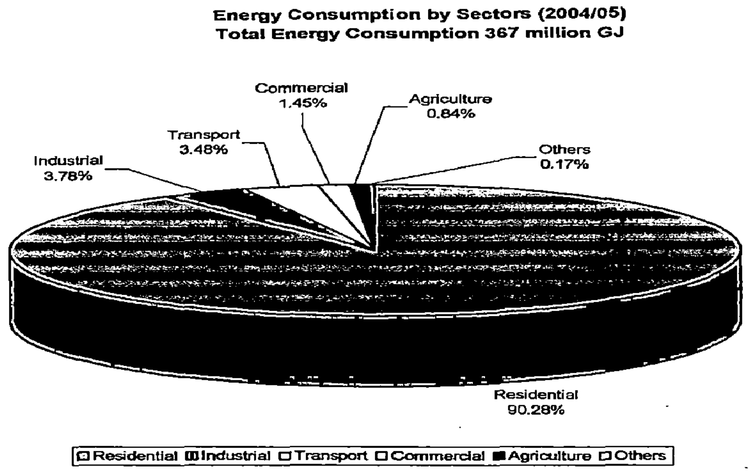
Figure 5.1: Energy Consumption by Energy Type



Fuel wood, representing 78% of the energy consumption, is mainly used in rural Nepal. During the period from 1978/79 to 1994, the total forest area in the country has decreased from 38% to 29% with a 1.7% deforestation rate. During the same period, shrub land has more than doubled from 4.7% to 10.6% (DFRS 1999 in National Climate Change Study Group/TU, Page 46). Some major causes of forest depletion can be attributed to clearance of forestland for agricultural use, and over dependency on forests to fulfill the fuel wood, fodder and timber requirements. On the other hand, the agricultural area has increased from 592,000 ha to a total area of 2,968,000 ha between 1985 and 1995 (UNEP 2001 in SNV/Nepal 2001).

Imported petroleum and coal together comprise about 10% of the total energy consumption. All commercial fossil fuels are imported, and account for about 25% of Nepal's foreign exchange earnings (Ministry of Finance in SNV/Nepal, 2001, Page 6). Petroleum products are the single largest import for Nepal. Over the next 20 years, the share of biomass in energy supply is expected to reduce gradually to about 70% under the medium growth scenario, mainly compensated by an increased share of commercial energy (WECS, 1999 in SNV/Nepal, 2001, Page 6). The rural population, which comprises of a little less than 90% of the total population, has minimal access to electricity and the per capita electricity consumption in 1999 was only 45.7 kWh (WECS, 1999 in CES, 2000, Page 4).

Figure 5.2: Energy Consumption by Sectors

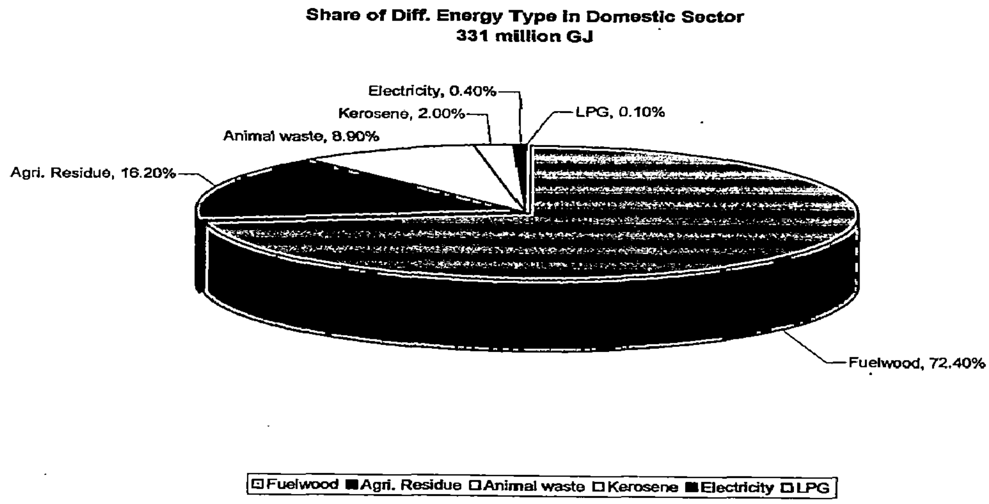


The low level of commercial energy consumption in the country reflects the very low level of industrial activities, which has changed little over the last decade. Energy consumption by the agriculture sector is negligible and is not reported in the above figure.

Residential Sector

Energy end-uses of the domestic sector are mainly for cooking and lighting. The total demand of 331 million GJ in the domestic sector in 2004/05 was met mostly by fuel wood, followed by 16.2% agricultural residue. Commercial energy consumption was nominal with kerosene and LPG making up 2% and 0.1% respectively in that year.

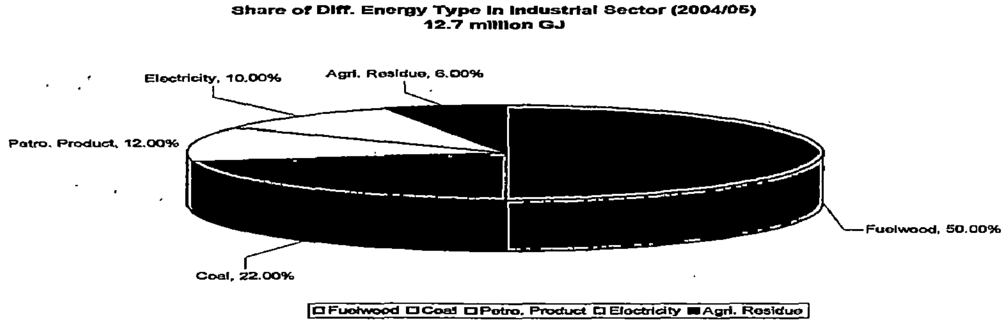
Figure 5.3: Share of Diff. Energy Type in Domestic Sector



Industrial Sector

With an estimated total energy demand of 12.7 million GJ in 2004/05, the industrial sector, at 50%, is also dominated by fuel wood. However, the share of other energy sources is also significant here. Coal and petroleum products contributed 22% and 12%. Agri. residue contributes 6% in these mostly agri. based industries.

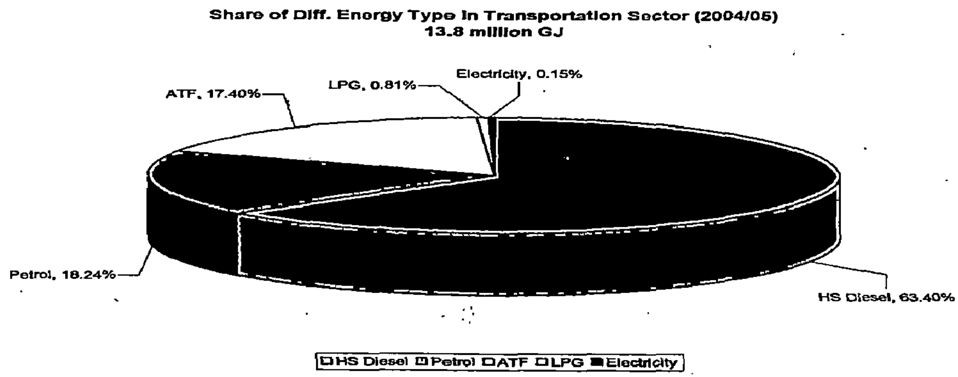
Figure 5.4: Share of Diff. Energy Type in Industrial Sector



Transportation Sector

This sector is heavily dependent on imported fossil fuels. The total demand in this sector in 2004/05 was estimated to be 13.8 million GJ, and increasing very rapidly at a energy consumption growth rate of about 4% annually. Diesel contributes 63% followed by petrol with 18%. Aviation Turbine Fuel (ATF) contributes 17% whereas the share of electricity and coal is very minimal. It is seen for the last few years that though in quantitative term, LPG's contribution is minimal; the growth trend is about 12% in this sector. Other fuels having high growth rate in this sector is ATF with 9% and Motor Spirit with 5%.

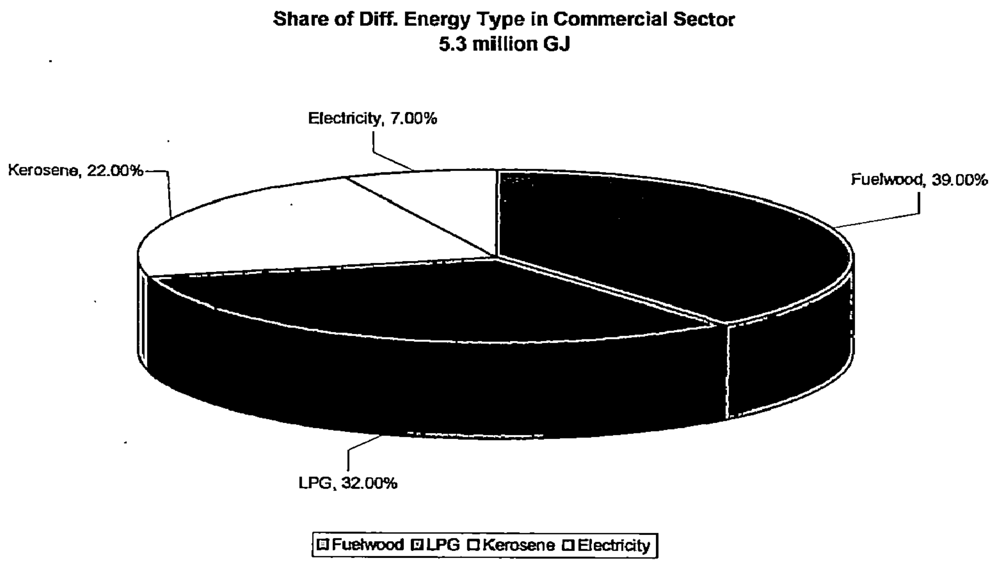
Figure 5.5: Share of Diff. Energy Type in Transportation Sector



Commercial Sector

This sector, which includes schools, hotels, government and non-government institutions, retail shops etc. has increased from 2.5 million GJ in 1995 to 5.3 million GJ in 2004/05 which shows an increase in 8% per annum. Fig. 5.6 presents the different share of fuel types consumed in the commercial sector. It is seen that fuelwood accounts with the highest share of 39% followed by LPG 32%, Kerosene 22% and then the electricity with 7%. For the last few years, it has been seen that LPG consumption growth rate in this sector is about 13%, while the growth rate of kerosene is in the decreasing trend. Fuelwood and electricity consumption growth rate is about 4% and 5% per annum respectively in this sector.

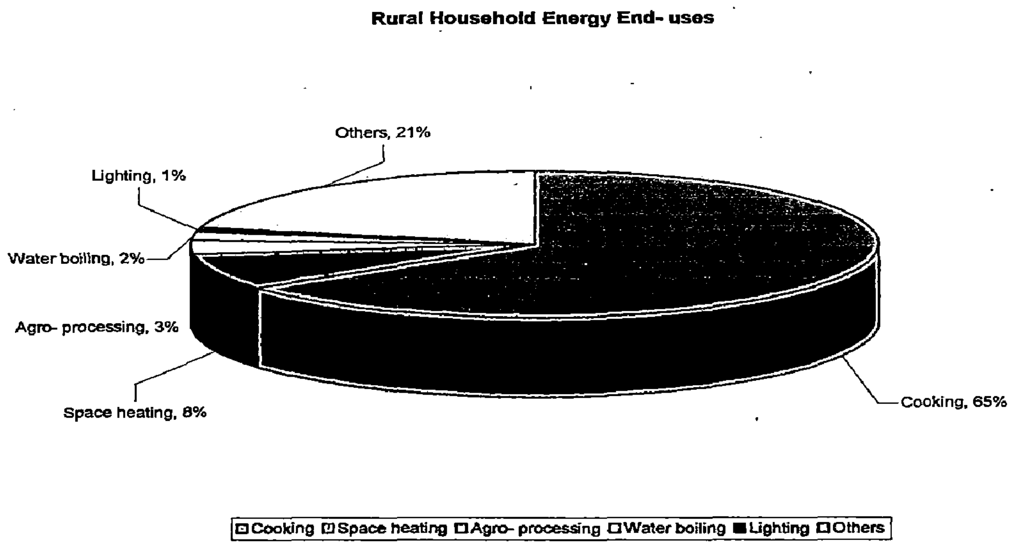
Figure 5.6: Share of Diff. Energy Type in Commercial Sector



5.2.2 Rural Energy Supply and Demand Situation

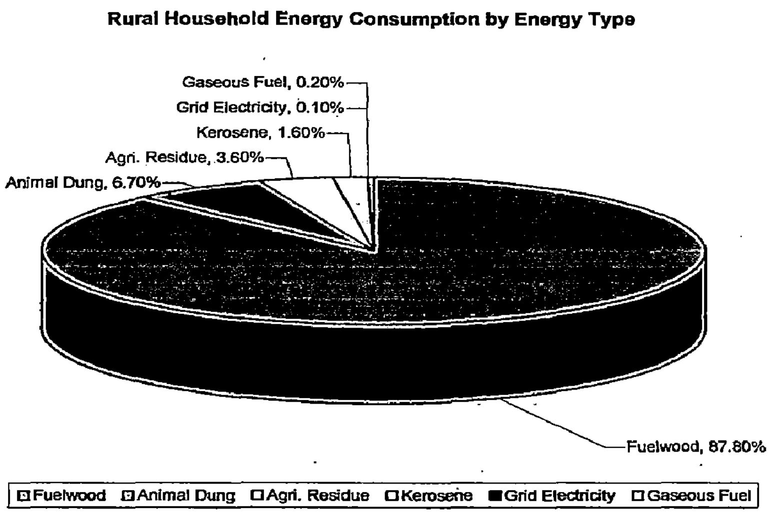
About 87% Nepalese live in rural areas with agriculture as the main livelihood. Energy consumption in rural areas constitutes about 87% of the country's total energy expenditure, and the residential sector accounts for 89% of the total energy consumption. Rural household energy end-uses and energy consumption by energy type for 1995 are presented (WECS 1995 in CES 2000, P. 5).

Figure 5.7: Rural Household Energy End-uses



From the perspective of energy end-use, residential cooking is a single activity that accounts for about 65% of the total energy consumption. The level of electrification was negligible in 1995; use of appliances was also negligible and is not even accounted for in the figure. Kerosene lamps are the most common lighting appliances in rural areas, consuming about 1 percent of the total rural energy consumption. It is also evident from the figure that rural energy demand is heavily dependent on biomass energy.

Figure 5.8: Rural Household Energy Consumption by Energy Type



5.3 CLEAN DEVELOPMENT RESOURCES IN NEPAL

Indigenous energy resources in Nepal consist of a combination of traditional and commercial sources including fuel wood, agricultural residue, animal waste, hydropower, solar and potentially wind energy as well. The theoretical potential of known indigenous energy sources, excluding solar energy, amounts to 1,970 million GJ annually on a sustainable basis, which indicates Nepal's potential to cover its energy requirements (PEP, 1995 in SNV/Nepal, 2001). Clean Development Resources covers renewable energy technologies mainly hydropower, biogas, solar power, biomass conversion and limited coverage of wind.

Nepal has abundance in natural resources with 224 billion cubic meters of annual run off and 300 sunny days in a year, with 6.5 hours average daily sunshine. The country also hosts 34 natural hot springs; in addition, the high mountains also have considerable wind energy potential (ENPHO & Welink Consultants, 2002, Page 54). Nepal's energy resources potential is estimated to be 1,519 million GJ annually on a sustainable basis, which would be 15 times the estimated total GJ consumption (Banskota & Sharma 1997 in ENPHO & Welink Consultants, 2002, Page 54). This indicates that there is sufficient potential of energy output of renewable sources. Besides biomass, there are other renewable energy sources, like hydropower, solar, wind and biogas, with great potential in Nepal.

Hydropower and cogeneration options have the potential to increase the capacity of the national grid to meet the transport and industrial needs and to expand rural electrification. Technologies dedicated purely to the domestic sector, namely micro-hydro, biogas and solar are anticipated to have positive impacts on replacing firewood (biogas, micro-hydro, ICS), kerosene lighting and diesel generators (solar PV, micro-hydro), and diesel agro-processing mills (micro-hydro), etc.

5.3.1 Hydropower Potential

In spite of being a small country, Nepal is home to some of the most significant tributaries of the mighty Ganges. The major river basins of Nepal are the Koshi, Gandaki, Karnali and Mahakali. Hydropower potential is shown in table 5.2.

Table 5.2: Hydropower Potential of Nepal (GW)

River basins	Small river courses Catchment areas 300 – 1000 km^2	Major river courses Catchment areas > 1000 km^2	Total theoretical	Economically feasible
Sapta Koshi	3.6	18.75	22.35	10.86
Sapta Gandaki	2.7	17.95	20.65	5.27
Karnali and Mahakali	3.5	32.68	36.18	25.1
Southern Rivers	1.04	3.07	4.11	0.88
Country Total	**10.84**	**72.45**	**83.29**	**42.13**

Source: WECS, 1994, Page 16

These estimates account for rivers with catchments areas of over 300 sq. km.. Assuming a minimum specific discharge of 5 liters per second per sq. km, the minimum discharge corresponding to the above catchments is 1.5 m^3 per second. The present exploitation of hydropower in Nepal is only a little higher than 1.5% of its economically feasible potential. The detail breakdown is given in Table 5.3.

Table 5.3: Share of Capacity and Energy by type of generation in INPS

S.N.	Type of Generation	Installed Capacity		Annual Designed Energy	
		MW	Share%	GWh	Share%
1	NEA Hydro	408.118	66.74	2155	71.06
2	NEA Mineral Oil	55.028	9.00	140	4.61
3	IPP Hydro	148.283	24.25	737.8	24.33
	TOTAL	**611.529**	**100**	**3032.8**	**100**

Source: NEA, Annual Report 2006

Local developers in Nepal are involved mostly in small power projects. Larger projects involving huge capital investment require external financial support as they are beyond the nation's financial capacity. Foreign investors are keeping a close watch on the market in the region, particularly in India. Snowy Mountain Engineering Corporation (SMEC) of Australia is holding negotiations with India for a Power Purchase Agreement (PPA) for the 750 MW West Seti Project and a Nepal-India joint committee is preparing a detailed project report on the 6,000 MW Pancheswor River in western Nepal.

The Tenth Plan clearly states that the major policies are to encourage private investment, develop public private partnership and adopt Build, Own, Operate and Transfer (BOOT) in order to extend the total installed hydroelectric capacity to 820 MW of which 70 MW will be exported. Moreover, 43 percent of the total population is expected to obtain access to electricity from national grid in the Plan period.

5.3.2 Cogeneration

Cogeneration is the simultaneous production of electricity and heat, both of which can be used. It offers an opportunity for local power generation close to the point of use and can enhance the energy economy of power generation with a much higher contribution from renewable fuel sources.

The sugar industry, with its built-in arrangement of steam production through the combustion of bagasse (the residue remaining after the juice has been extracted from cane stalks) has by far the biggest potential for cogeneration of power. It is estimated that a sugar plant of an average capacity of 2,500 tons of crushing per day (TCD) can generate about 11 MW of electric power and can supply surplus power of 8 MW to the grid as per the experience in India. With this reference, 80 MW of electric power generation potential is anticipated from the currently existing sugar industries in Nepal, around 60 MW of which can be supplied to the national grid (CES 2000, Page 29). However, there is a need for an in-depth study to furnish the actual figures. There is a need for clear national policy guidelines and a coordinated approach to enable this potential to be profitably exploited in the near future.

5.3.3 Micro-Hydropower Potential

According to the Micro-hydro Yearbook of Nepal 2002 (page 6), a total of 371 micro-hydro schemes with a total capacity of 5,068.2 kW and 875 peltric set units with a total capacity of 1,471.9 kW have been installed in Nepal for the purpose of rural electrification. The 10th Five Year Plan has set a target of 10 MW of power generation from micro-hydro. In addition to this, there are also 800 MHP schemes with the total installed power of 7,074.9 kW for mechanical power used for milling purposes. Such micro-hydro milling, improved ghatta, etc. also have great potential to replace diesel mills in rural areas. CRT has been involved in promoting Improved Ghattas for quite some time and has installed around 1,000 units through GTZ and other donor support. At present, SNV/CRT are promoting around 4,000 Improved Ghattas in rural areas. Assuming 1 kW of power generated by each improved ghatta (the capacity will depend upon the flow and head available), the total power generated would amount to a noteworthy 4,000 kW. Detailed information on their potential to reduce GHG emissions is not fully known at this stage.

5.3.4 Biogas Potential

Livestock play an important role in an agriculture-dependent country like Nepal. The total cattle and buffalo population in Nepal was estimated to be 9.3 million (i.e. 6.3 million cattle and 3.0 million buffalo) in 1990/91. Based upon the study of the technical biogas potential of Nepal, it is assumed that a total of 28.1 million ton of dung would be available per day for biogas production (BSP, 2003, Page 4). This indicates that there is a high potential of biogas production in Nepal on the whole.

Table 5.4: Region wise biogas potentiality and production

Region	Household With Animals	Potential Biogas Household	Production Biogas Household
Remote Hill	314,874	139,111	2,592
Hill	1,005,188	461,340	50,118
Terai	891,925	891,925	42,752
Total	**2,211,987**	**1,492,376**	**95,462**

Source: BSP, 2006

The potential number of biogas plants in Nepal was estimated to be about 1.9 million in 2001 by BSP out of which 57% are expected in the plains, 37% in the hills and the remaining 6% in the mountain region. BSP, however, has estimated that only around 1000,000 plants would be economically promising. Biogas is being ardently promoted by numerous organizations, there were 140,549 plants at end of Dec 2005 plants installed with support from BSP alone throughout the country. The Tenth Five Year Plan has set a target of installing 200,000 (including 500 community biogas plants) new biogas plants in the plan period.

5.3.5 Improved Cooking Stoves

The average annual household consumption of fuel wood in Nepal is about 3,666 kg (WECS 2001 in ENPHO & Welink Consultants, 2002, Page 58). Fuel wood is primarily burnt in traditional or open fire stoves. Each rural household possesses at least one traditional and/or open fire stove. According to CBS 2001, there are 4.3 million households in the country, out of which 85% are in rural areas, i.e. about 3.6 million households. As a result, there is a high potential for ICS to reduce fuel consumption in the domestic sector. The country requires a simple technology that can contribute towards reducing the imbalance between supply and demand of energy sources as the large percentage of the population still depends upon biomass fuels using traditional stoves. Increased access to ICS would benefit small and poor households in rural areas in particular, fulfilling their energy needs, especially where there are no biogas plants.

The global warming potential (GWP) of a meal cooked on a biomass stove can actually exceed that of fossil fuels, even if based on renewably harvested fuel (Smith, K. et. al. 2000, P. 741) because typical biomass stoves are thermally inefficient and divert substantial fuel carbon to products of incomplete combustion which will conversely make their per meal emissions high. Thus in Nepal's case, further investigation is needed to gauge the actual impacts of ICS on GHG emissions.

5.3.6 Solar Power

Nepal has about 300 days of sunshine per year and the average insolation for Nepal ranges between 4 to 5 $kWh/m^2/day$. The total solar energy potential in Nepal is estimated to be about 27 million MW (WECS, 1994, Page 24). The total installed capacity of photovoltaic systems in Nepal is increasing day by day. Since 1989, NEA has a centralized PV power system totaling 100 kWp at two locations: Simikot (50 kWp) and Gumgadhi (50 kWp) whereas the 30 kWp system in Kodari/Tatopani has already been dismantled. The detailed data available illustrates that the total capacity of solar power has exceeded 1MWp (excluding SHS).

5.3.7 Solar Home Systems

The potential scope for SHS installation in Nepal is believed to be in excess of 100,000 systems. The Tenth Five Year Plan has set a target of installing 3.5 MW from the 52,000 domestic and institutional solar home systems. However, the success of household electrification through SHS lies in overcoming the high initial costs, quality control and services through a market based approach and ensuring appropriate support from the government and donors. As of July 20, 2003 (AEPC homepage, July 28, 2003) there were already 23,245 SHS installed in 66 districts of Nepal with total power generation of 885.749 kW through AEPC/ESAP.

5.3.8 Solar Thermal Energy

Solar water heaters and solar dryers are the two main types of solar thermal systems. An estimated 17,265 households, 270 commercial establishments and 26 public institutions are currently using solar water heaters. It is estimated that about 120 manufacturers are currently producing water heaters throughout the country. The highest concentration of SWH installations is in the urban centers of Kathmandu and Pokhara; Kathmandu alone accounts for over 80% of domestic SWH users (CES, 2000, Page 52). The potential of solar water heaters for hotels is presented under energy efficiency.

Solar dryers of various types have been used in 14 districts (763 box type and 37 cabinet type) throughout the country. Dissemination of solar dryers has been limited due to its high cost and lack of product specific designs. The Centre for Rural Technology, Nepal (CRT/N) has been promoting the use of solar cookers (200 box type and 130 parabolic). The main problems for the wide spread dissemination of this technology are uncertainty of sunshine, preference for fried food and adherence to traditional culture and eating habits (CES, 2000, Page 56).

5.3.9 Wind Energy Potential

Nepal's efforts to harness wind energy has resulted in a series of failures in the past. The main lesson learnt is that thorough and reliable wind analysis has to be made before a wind power project is undertaken. Few initiatives include three wind turbines for pumping water by Krishna Grill and Engineering Works (KGEW) in Biratnagar and a 900-watt wind solar hybrid system in a hotel resort in Kavre district. A preliminary survey of Department of Meteorology and Hydrology indicates that wind energy can be used for generating electricity and pumping water in the hills and Terai respectively. A study with support from the World Bank in Khumbu, Solukhumbu district in 1997 found that the average wind speed is 5 m/s and the electricity thus generated would be cheaper than the cost of kerosene in that region. The potential survey done by Dangrid in 1992 with UNDP support indicates that 200 MW of wind power can be produced in the 12 km corridor from Kagbeni to Chusang alone. It is estimated that 500 GWh electricity can be generated annually (CES, 2000, Page 66). Some other potential sites identified are Karnali river along East-West highway, Batase Danda (Palpa), Rampur (Chitwan), Tarhara (Sunsari), and the Arun Valley. There are 48 wind-measuring stations in Nepal and RONAST and NEA have an additional one each. It seems that small scale (50W – 1kW) wind generators may be a feasible proposition for meeting lighting requirements, supporting communication and social infrastructure in remote and isolated areas (Bhadra1998 in ENPHO & Welink Consultants, 2002, Page 59).

5.4 GHG EMISSIONS INVENTORY

According to the World Development Report 2003 (P. 235), Nepal's share in the total CO_2 emissions was 3 million tons of CO_2 in 1998. The following details for GHG emissions in Nepal are mostly based on the draft National GHG Inventory study.

According to Table-5.7, the net national emissions of CO_2, CH_4 and N_2O were estimated at 9,747 Gg, 877 Gg and 30 Gg respectively for the base year 1994/95. Of the five categories included in the inventory, the Land use Change and Forestry sector, with total emissions of 22,895 Gg is the strongest source of CO_2 followed by the Energy sector with 1,465 Gg. In the base year, Land use changes and the forestry sector indicated a total CO_2 removal of 14,778 Gg because of strong intake of CO_2 through forestry management and plantation as well as abandonment of managed land. This feature is important because it indicates that the atmospheric concentration of CO_2 can be partially mitigated. Moreover, methane and nitrous oxide were also emitted by agriculture and solid waste sectors. In fact the most important net GHG source in the country is methane from agriculture, which is 18,207 Gg of CO_2 equivalent considering global warming potential of methane as 21.

Fossil fuel combustion in transportation, industrial, domestic, commercial and also in agricultural sectors is the major anthropogenic source of CO_2 emissions. The total CO_2 emission from fossil fuel consumption in the base year was estimated at

1465 Gg. Some other non-energy production processes like cement production also emit a significant amount of CO_2. In 1994/95, the total CO_2 emissions resulting from cement production was 163 Gg and that from lime production was about 2 Gg.

Changes in land use and forestry activities both emit CO_2 (e.g. as a result of forest clearing) and can act as a sink for CO_2 (e.g. as a result of improved forest management activities). In total, 14,738 Gg of CO_2 was sequestrated due to biomass growth and 40 Gg of CO_2 was absorbed by the re-growth in abandoned, previously managed land. Conversion of forestland to other land use categories also affects the carbon in the soil. In the base year 1994/95, CO_2 emissions from soil carbon loss from different land use systems was estimated at 4,348 Gg. Similarly, 18,547 kilo ton of CO_2 was released due to the forest conversion to grasslands. Thus, the total net emissions from the land use change and forestry sector was about 8,117 Gg in the base year.

The agriculture sector is the major sector contributing the bulk of methane emissions in the country, including emissions from enteric fermentation, rice cultivation and agricultural crop residue, followed closely by the waste sector. The agricultural sector contributed an estimated 867 Gg of the total methane emissions for the base year 1994/95. The three different sources, namely, disposal of solid waste, treatment of domestic and commercial wastewater and treatment of industrial wastewater were considered in order to estimate methane emissions from the waste sector. For the base year 1994, the total methane emissions from these three sources were 10.47 Gg.

The major source of N_2O emissions in 1994/95 for Nepal was agriculture soils. The total N_2O emissions were 29 Gg of which 93% was contributed by agricultural soils and the remaining 7% by animal waste management systems. After treatment in a septic system or wastewater treatment facility, sewage is disposed on land or discharged into aquatic environments such as rivers and streams. N_2O may be generated during treatment and disposal through nitrification and de-nitrification of the nitrogen that is present in sewage. The indirect N_2O emission for the base year 1994/95 was 1.10 Gg. Table-5.7 below shows the sectorwise GHG emission inventory data.

Table 5.5: National Greenhouse Gas Inventory of Anthropogenic Emissions by Source and Removals by Sinks for base year 1994/95

Unit: Gg (1 Gg = 1 kilo ton)

Greenhouse Gas Source and Sink Categories	CO_2 Emissions	CO_2 Removals	CH_4	N_2O
1. Energy	**1465**			
1.1 Fuel Combustion (Sectoral Approach)				
1.1.1 Energy Industries	71			
1.1.2 Manufacturing Industries and Construction	320			
1.1.3 Transport	456			
1.1.4 Other Sectors	618			
1.2 Fugitive Emissions from Fuels	0			
2. Industrial Processes	**165**			
2.1 Mineral Products				
2.1.1 Cement Production	163			
2.1.2 Lime Production	2			
2.1.3 Solvent and Other Product Use	0			
3. Agriculture			**867**	**29**
3.1 Enteric Fermentation			527	2
3.2 Manure Management				
3.3 Rice Cultivation			34	
3.4 Agricultural Soils			306	
				27
4. Land-use Change & Forestry	**22895**	**-**		
4.1 Changes in Forest and Other	0	**14778**		
Woody Biomass Stocks		-		
4.2 Forest and Grassland Conversion	18547	14738		
4.3 Abandonment of Managed Lands				
4.4 CO2 Emissions and Removals from	4348			
Soil		-40		
		0		
5. Waste			10	1
5.1 Solid waste disposal land			9	
5.2 Wastewater handling			1	
5.3 Waste Incineration				
5.4 Other				1
Total emissions and Removals	**24,525**	**-14778**	**877**	**30**
Net Emissions	**9,747**		**877**	**30**

Source: National Climate Change Study Group/ TU, 2002 Page iv.

CHAPTER-6

NEPAL BIOGAS SUPPORT PROGRAMME (BSP-NEPAL) – A CASE STUDY

This chapter provides an example on preparation of project design document in accordance with approved format specified by UNFCCC Executive Board. The example pertains to Biogas Support programme in Nepal. The data for preparation of PDD has been obtained from Biogas Support Programme office in Kathmandu (Nepal).

6.1 DESCRIPTION OF THE SMALL SCALE PROJECT ACTIVITY

Under the proposed project activity, the Alternative Energy Promotion Center aims to sell biogas digesters (biogas plants) to households located primarily in the rural areas of Nepal. The project activity will reduce greenhouse gas (GHG) emissions by displacing conventionally used fuel sources for cooking, such as fuel wood and kerosene.

Despite the government's past efforts to develop the biogas market with the support from international donors, namely the German Development Bank (KfW) and the Netherlands Development Agency (SNV), the investment in the biogas sector is a non-commercial activity in Nepal.

In this context, an MoU was signed by the Alternative Energy Promotion Centre (AEPC) and the World Bank in 2004 to develop CDM project in the BSP of Nepal, starting from development of a methodology. The MoU included trading of Emission Reduction equivalent to 1 million tons of CO2. Two small scale CDM Projects with a total of 19,396 biogas plants disseminated all over Nepal from July 2003 to April 06, 2005 were already registered with the CDM Executive Board in December 2005 and approved.

Consequently, an Emission Reduction Purchase Agreement (ERPA) was signed by the AEPC and the World Bank in May 2006 for trading of the Emission Reductions (ERs) from the two CDM Projects for 7 years. An Implementation Agreement was also signed in May 2006 between AEPC and Biogas Support Programme-Nepal (BSP-Nepal).

The key objective of the umbrella program is to develop the donor-supported biogas program as a commercial activity with the integration of carbon revenues to serve a large rural population.

The proposed study is considered as the third project activity that installed a total of 9,759 small biogas digesters from April 07, 2005 to December, 2005 in a number of districts of Nepal as shown below in Table 6.1.

A biogas plant produces biogas, thermal energy for cooking. The power equivalent of the installed biogas plants ranges from 1.16 KW to 2.32 KW and the total installed equivalent generation capacity of the proposed project activity totals 14.77 MW. Since the total installed equivalent generation capacity of the proposed project activity is less than 15 MW, so the proposed project activity falls under small scale CDM project category.

Table 6.1: Distribution of Biogas Plants from April 07, 2005 to December, 2005

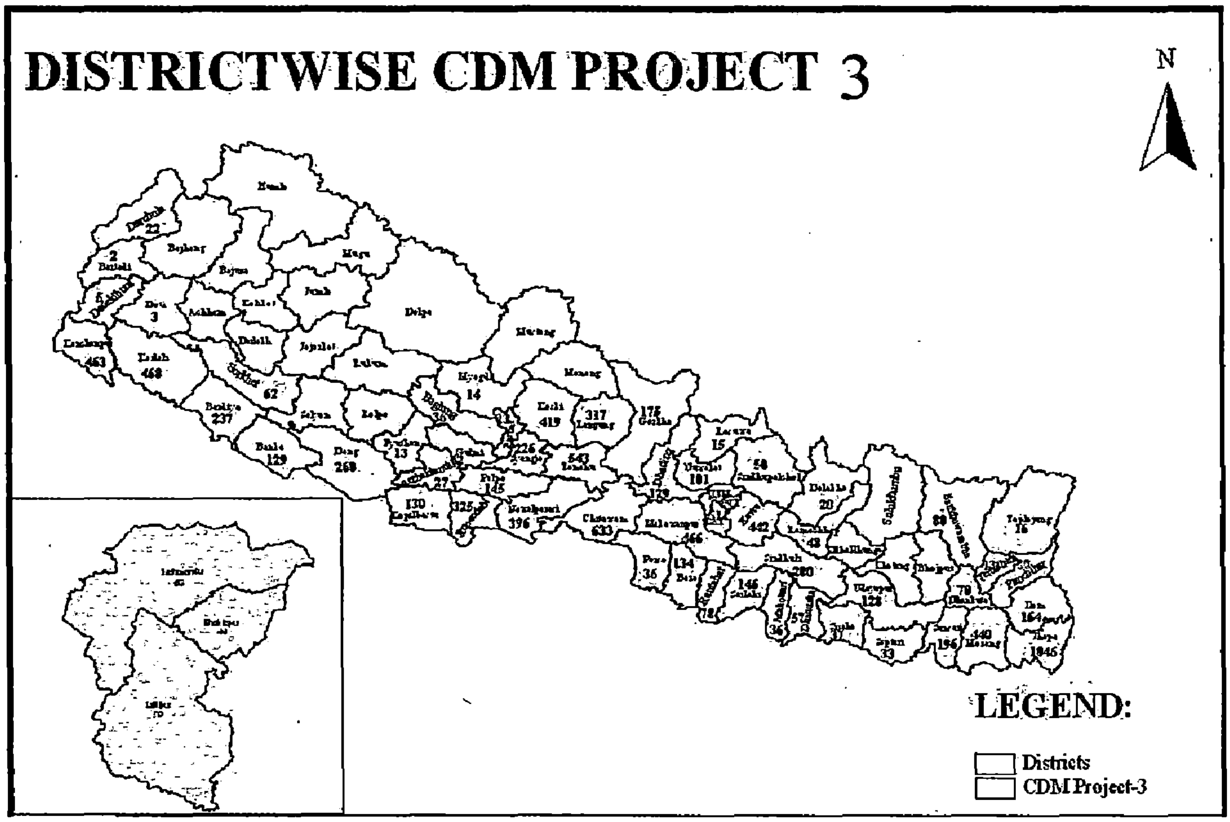
Districts	Number of Plants	Districts	Number of Plants	Districts	Number of Plants
Arghakhachi	27	Jhapa	1060	Ramechhap	48
Baglung	36	Kabrepalanchowk	443	Rasuwa	17
Baitadi	2	Kailali	471	Rautahat	84
Banke	132	Kanchanpur	468	Rupandehi	325
Bara	143	Kapilbastu	132	Sankhuwasabha	82
Bardiya	236	Kaski	437	Saptari	33
Bhaktapur	49	Kathmandu	96	Sarlahi	155
Chitawan	660	Lalitpur	61	Sindhuli	203
Dadeldhura	5	Lamjung	319	Sindhupalchowk	50
Dang	264	Mahottari	37	Siraha	38
Darchula	36	Makawanpur	489	Sunsari	205
Dhading	129	Morang	470	Surkhet	62
Dhankuta	78	Myagdi	14	Syangja	238
Dhanusa	63	Nawalparasi	417	Tanahu	550
Dolakha	23	Nuwakot	99	Taplejung	16
Doti	3	Palpa	145	Terathum	13
Gorkha	176	Panchther	32	Udayapur	130
Gulmi	42	Parsa	37	**Total 9759**	
Ilam	166	Pyuthan	13		

6.1.1 Location of the Proposed Project Activities

The biogas plants under the proposed project were sold across various locations in 55 districts out of 75 districts of Nepal. The technology is best suited to the warmer districts existing below 2,000 m altitude; hence these districts are located mostly in the Terai and the Hills. BSP-Nepal will rely on around 60 companies to sell plants through their 200 branches located in different parts of the country.

BSP-Nepal keeps record of the addresses of each household buying biogas plants under its program to allow for field surveys and for monitoring over the lifetime of the project. The plant record includes exact unique plant identification code, physical location, name of biogas household, size of plant, date of construction, and name of the construction company. The geographic location details of the plant distribution are given in the map below.

Figure 6.1: Location of the biogas plant districts



6.1.2 Project category applicable to the small-scale project activity

Household biogas digester plants provide biogas for the thermal energy needs of households with at least 2 heads of cattle (cow or buffalo). Biogas plants are generally held by farming households living in villages. The biogas digesters are based on a uniform technology manufactured and installed following BSP-Nepal's technical standards. All biogas digesters sold will be registered under BSP-Nepal and their performance monitored through field surveys of a random sample of the installed households. The biogas production of biogas plants will not be metered.

The key features are:

1. The baseline and project emissions are based on the emission patterns of a number of randomly selected households. In a field survey, data are collected on both baseline and project emissions by interviewing households.
2. The emission reduction factor is expressed as the net emission reductions of a biogas plant i.e., baseline emissions minus project emissions. The standardized

Emission Reduction Factors are determined for different biogas plants based on their geographic location and size.

These factors are applied to all biogas plants sold under BSP-Nepal that meets the same specification. With reference to the modalities and procedures for small-scale projects, the above approach based on emission reduction calculation will cover the impact of use of biogas on conventional fuel reduction (such as fuel wood and kerosene).

6.1.3 Project Additionality

A small-scale CDM project activity is additional if anthropogenic emissions of greenhouse gases by sources are reduced below those that would occur in the absence of the registered CDM project activity and the project activity is facing one or more barriers as defined in Attachment A to Appendix B of the simplified modalities and procedures for small-scale CDM project activities. Several barriers related to investment and technology are described below and hinder the development of the proposed bundle of small-scale CDM activities.

The additionality of the proposed project below is demonstrated in two steps. Since the proposed project activity is a sub-activity of the BSP-Nepal Umbrella Biogas Program, the first step examines the issue of additionality at the level of the umbrella program aiming to install all 200,000 new biogas plants. The second examines the additionality issue at the level of the households to be enrolled in the project.

6.1.4 Debundled Component

The proposed project is not a debundled component of the BSP-Nepal umbrella biogas program according to the "debundling" rules explained earlier.

According to the rules, a small-scale project is a debundled component of a larger project if there is a registered small-scale activity or an application to register another small-scale activity:

With the same participants;

- In the same project category and technology/measure;
- Registered within the previous 2 years; and
- Whose project boundary is within 1 km of the project boundary of the proposed small-scale activity at the closest point.

The project participants of the proposed project are different from the project participants of another similar sub-project under the BSP-Nepal umbrella that has an application to be registered as a small activity, thereby clearly demonstrating that the project is not a debundled component.

6.1.5 Contribution to Sustainable Development

At the local level, the BSP-Nepal program has multiple social benefits. A major household benefit is the reduction in time and energy spent by women and children in collecting firewood for cooking. The project will attach latrines to biogas plants providing better sanitation to rural households. Potential employment will add more than 15,000 people-years for skilled people in the construction, maintenance, marketing, and financing of biogas plants. The use of biogas means negligible smoke, hence better family health. Moreover, the residual biological slurry from the biogas plants can be used as superior organic fertilizers to enhance agricultural yields.

At the national level, the proposed umbrella program supports the Nepali Government's sustainable energy goals as laid out in 10th Five Year Plan to improve energy access for rural poor and to reduce rural poverty by providing high quality biogas plants to poor households at an affordable price.

Additionally, the project will support forest conservation goals by substituting the traditionally cooking fuel, i.e., firewood, with biogas fuel.

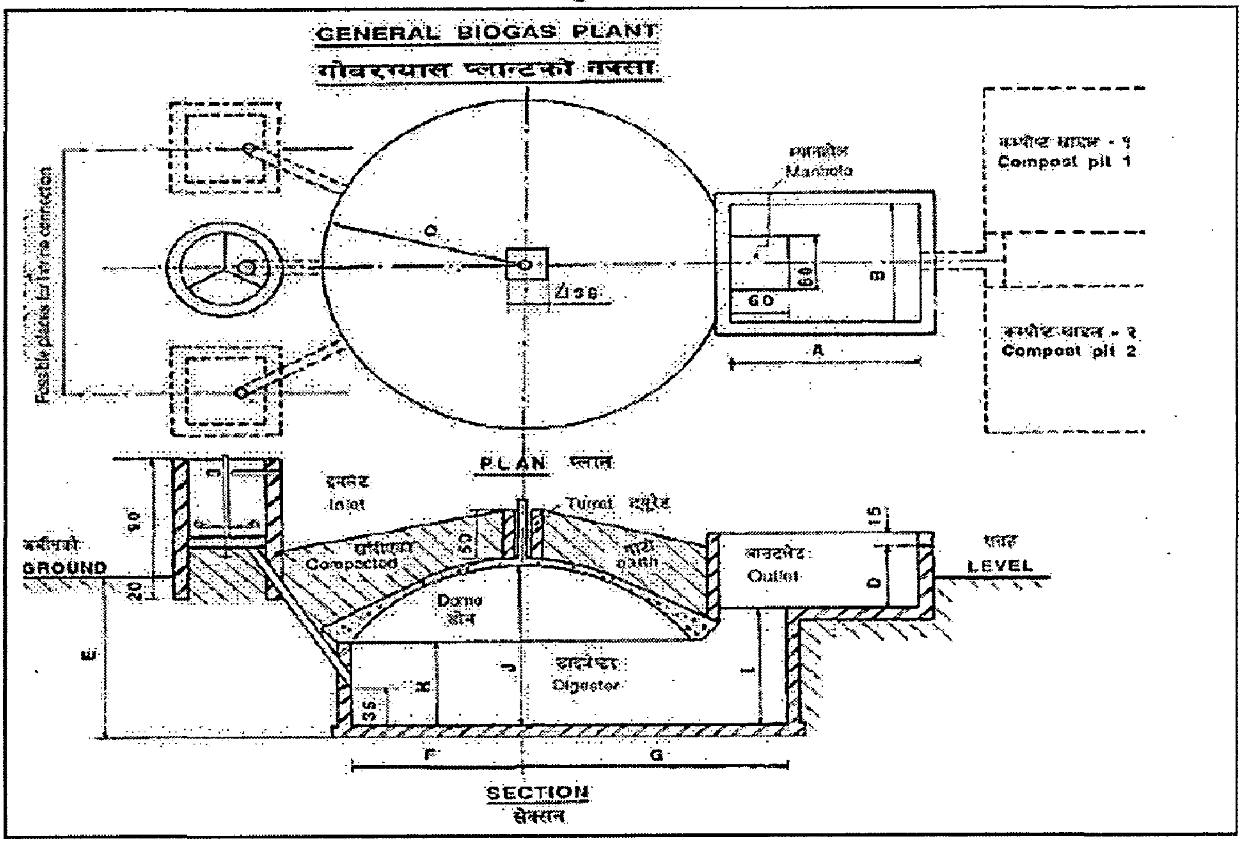
Each **biogas household** is the participant of the project who decides to invest in a biogas plant and owns emissions reductions generated thereafter. All but two households agree by contract to transfer the CO2 credit and all other rights associated with the transaction and administration of these ERs to the Alternative Energy Promotion Centre.

6.1.6 Technology of the Project Activity

The household biogas digester plants to be sold under this proposed project activity will provide biogas for the thermal energy needs of households with at least 2 heads of cattle (cow or buffalo) and will displace fossil fuel and/or non-renewable biomass products (firewood). Farming households living in villages in remote areas are the primary buyers of biogas plants. The biogas plants are based on a uniform technical design and are manufactured and installed following established technical standards in Nepal. The households will feed dung of cattle (cows or buffaloes) mixed with water into the biogas plant, which through anaerobic digestion will produce biogas. The retention time of the slurry inside the tank is around 3 months. The figure below shows the technical design of the biogas plant.

All biogas appliances except the main valve are produced locally, and are of good quality. Regarding the main valve, the limited biogas market does not justify the necessary investment for local production as yet; therefore the valves are imported from the Netherlands, Italy and/or Thailand. BSP-Nepal also provides R&D support and technical assistance to the individual companies.

Figure 6.2: General design map of biogas plant



6.2 BASELINE METHODOLOGY AND GHG EMISSION REDUCTIONS BY SOURCES

6.2.1 Baseline Methodology

The baseline approach adopted for the analysis is based on the small-scale CDM project activity categories contained in appendix B of the simplified M&P for small-scale CDM project activities. The baseline for the category I..C. Thermal Energy for the User under Type I, Renewable Energy Projects, is defined as follows: "For renewable energy technologies that displace technologies using fossil fuels, the simplified baseline is the fuel consumption of the technologies that would have been used in the absence of the project activity times an emission coefficient for the fossil fuel displaced. IPCC default values for emission coefficient may be used." "For renewable energy technologies that displace non- renewable sources of biomass, the simplified baseline is the non-renewable sources of biomass consumption of the technologies times an emission coefficient for the non-renewable sources of biomass displaced. IPCC default values for emission coefficient may be used."

The biogas digester systems proposed in this study generate heat for their owners (households) and displace fossil fuels and/or non-renewable sources of biomass (kerosene and fuelwood). As such this project qualifies under Section I-C of Appendix B of the small-scale guidelines.

6.2.2 Specification of baseline

The approach to the baseline is the calculation of the net emission reduction factor per biogas plant. In line with the spirit of the baseline methodology specified in appendix B of the simplified M&P for small-scale CDM project activities, a process consisting of 5 steps is followed to determine the net emission reductions:

Step - 1: Identification of baseline and project emission sources;

Step - 2: Identification of emission factors;

Step - 3: Identification of activity volumes;

Step - 4: Calculation of emissions per source;

Step - 5: Calculation of emission reduction factor per plant per region.

Step - 1: Identification of baseline and project emission sources

Baseline and project emission sources have been identified as listed in Table 6.3

Step - 2: Identification of emission factors.

Manure - In accordance with the Nepal national GHG inventories, the emission factors for dairy, nondairy cattle and for buffaloes are taken from the IPCC Tier 1 approach. IPCC Tier 1 emission factors rely on default emission factors drawn from previous studies. The Tier 1 approach is likely to be sufficient for most animal types in most countries. Tier I methodology emission factor for India & subcontinent assumes that half of the dung is used for fuel and the remainder is managed in dry lots. This is in line with the situation in Nepal. Estimated dung use for fuel in Terai is roughly 46% and in Hills around 36%. For chemical fuel/methane leakage the default emission factors have been taken from the IPCC. GWP of methane is 21.

Step - 3: Identification of activity volumes.

The following activity volumes need to be measured:

- Amount of fuel saved per household

- Amount of methane leakage from biogas digesters into the air.

Data sources used to estimate volumes:

- BSP-Nepal's Environmental Impact Study – This Study includes an extensive household survey among 1,200 households (600 biogas users, 600 non-users) which has been used to assess changed household behavior in relation to consumption of fossil fuels and fuel wood due to the introduction of biogas digesters.
- BSP-Nepal's database on biogas users - This database contains a wealth of information from the BSP-Nepal quality control program on the total population of biogas plants sold so far in Nepal (totaling over 100,000). Information is mostly technical and related to gas production, such as cow dung fed into biogas digesters.

In measuring the emission volumes the following factors have been taken into account:

- Size – emission reductions are likely to be a function of the amount of biogas produced and consumed which in turn is determined by the size of biogas digester. The most common biogas digester plants sold under BSP-Nepal are 4 m^3 , 6 m^3 , 8 m^3 and 10 m^3 . Incidentally, also systems of 15m^3 and 20 m^3 are sold, although these larger plants are no longer recorded by BSP-Nepal. These systems have been included in the category 10 and larger.
- Geographic zone – As previously mentioned, Nepal is characterised by three distinctive geographic zones: Terai, Hills, Mountains. The different environments and possible different habits of people living in these zones may have an impact on the volume of baseline and project emissions. In the case of Nepal, the data have been distinguished between these three regions.

Step - 4: Calculation of emissions per source

The emissions per source have been calculated according to a specific calculation formula, which combines the activity volumes per plant per region with the emission factor.

Step - 5: Calculation of emissions reduction factor

For each plant in each region the emissions for the various sources have been aggregated (baseline emissions minus project emissions) resulting in one emission reduction factor per plant per region.

6.2.3 Estimation of GHG Emissions by Sources

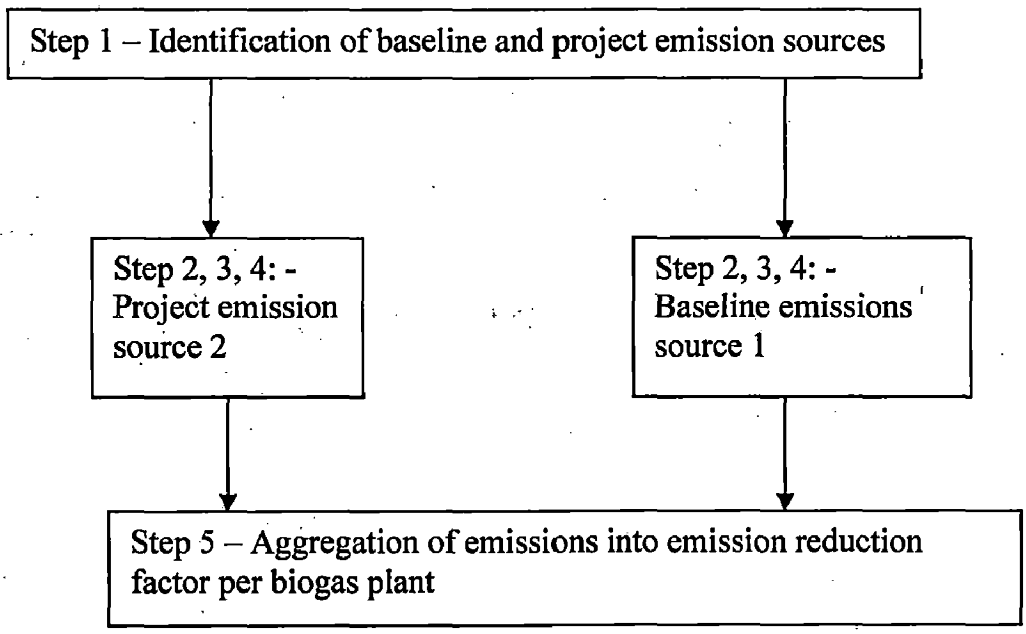
The approach to the baseline of the proposed project is based on the calculation of a standardized emission reduction factor per biogas plant taking into account both baseline emissions and project emissions. For clarity and flow of presentation, all emission sources and their calculations are therefore discussed below.

Estimation of Leakage

There is no leakage due to the project activity. In the project baseline, the supply and demand of the cattle manure is confined within the project boundary of an individual household. The wet manure is used as compost for the household's own use and the dry manure as dung-cake for cooking. Since the biogas plant will generate more efficient and clean fuel to substitute for the previously used cow dung, the net effect on the cow dung availability will be zero. Similarly, the biogas plant produces residual bio-slurry that has superior fertilizer value than the compost fertilizer.

Any other potential emission sources and possible leaks within the project boundary were identified and incorporated in the formulae to calculate the standardized emission reduction as indicated below.

The baseline methodology steps outlined above have been followed to calculate the standardized emission reduction factor (see figure below).



Source 1: Fuel Displacement

Source 2: Fugitive emissions from leakage in biogas digester and incomplete combustion

Step 1: Identification of emission sources

Table 6.2 Overview of emission sources

Emission source	**Baseline**	**Project**
Fuel use	CO_2 emissions from kerosene	None
	CO_2 emissions from burning unsustainable fuel wood	None
	CH_4 emissions from burning of fuel wood	None
Fugitive		Biogas (CH_4) leaks from digester and incomplete combustion

Step 2, 3 and 4 per emission source

Below for each source, step 2, 3 and 4 are outlined.

Fuel baseline

I. CO_2 emissions from kerosene:
Emission factors (step 2):
2.41 kgCO_2/liter kerosene.

Volume estimation (step 3):
- Consumption of kerosene per day before installation (in litres/day);
- Consumption of kerosene per day after installation (in litres/day).

Calculation of emissions (Step 4):
Calculation formula for each plant size per region in tCO_2eq/year:
- Kerosene savings in litres per day* 365 * 2.41 kgCO_2/liter/1000.

II. CO_2 emissions from fuel wood:

Emission factors (step 2):
1.83 kgCO_2/kg of fuel wood.

Volume estimation (step 3):
- Average consumption of fuel wood per day before installation (in kg/day);
- Average consumption of fuel wood per day after installation (in kg/day);
- Share of unsustainable fuel wood consumption per household.

Calculation of emissions (Step 4):
Calculation formula for each plant size per region in tCO_2eq/year:
- Fuel wood savings in kg per day * % of unsustainable fuel wood consumption per hh * 365 * 1.83 kgCO_2/kg of fuel wood/1000.

The methodology utilized to claim non-renewable biomass as a source of emission reductions shows that all 100% fuelwood consumption in a biogas household should be considered unsustainable.

III. CH4 emissions from fuel wood burning

Emission factors (step 2):

- 3.0g C methane emissions from burning 1 kg fuel wood
- 1 gC = 1.3 gCH4
- 21 tCO2eq/tCH4 = GWP of methane

Volume estimation (step 3):

- Average consumption of fuel wood per day before installation (in kg/day);
- Average consumption of fuel wood per day after installation (in kg/day);
- Share of unsustainable fuel wood consumption per household.

Calculation of emissions (Step 4):

Calculation formula for each plant size per region in tCO2eq/year:
3.0 gC * 1.3 gCH4/gC /1,000,000 * 21 tCO2eq/tCH4 * fuel wood savings in kg per day * 365

IV. CH4 emissions from biogas leakage from the digester

Emission factors (step 2):

- GWP(CH4) = 21tCO2eq/tCH4
- 12.5% = Methane leakage per biogas digester (= conservative estimation based on IPCC range of 5-15%)
- 0.71 kg/m^3 = density of methane

Note: Although the IPCC range is between 5-15%, the methane leakage of 12.5 % is assumed taking into account both leakage from biogas digester and CH4 emissions from incomplete combustion.

Volume estimation (step 3):

- Biogas production in m3 per plant;
- Methane concentration in biogas in percentage;

Calculation of emissions (Step 4):

Calculation formula for project CH4 emissions per plant size per year =
m^3 biogas production * % methane concentration in biogas * 0.71 kg/m^3 * 12.5% * 21 tCO2eq/tCH4

Step 5 – Aggregation of emission per source into standardised emission reduction factor

Emission reduction factor for a biogas plant of size a in region b =
+ CO2 emissions from kerosene savings in tCO2eq (I)
+ CO2 emissions of fuel wood savings in tCO2eq (II)
+ CH4 emissions from fuel wood savings
- CH4 leakage emissions from biogas digester in tCO2eq (V)

The approach to the baseline is based on the calculation of a standardised net emission reduction factor per biogas plant per region. The following describe steps to calculate the emission reductions due to the project activity during a given period.

1) Number of installed biogas plants under the project = N
2) Determine annual performance ratio of the installed biogas plants in year 1 given by
P1 = Total Number of Biogas Plants that are operational/Total Number of Biogas Plants Sold

whereby 0 < P1 < 100%

3) Determine Emission Reduction Factor applicable to the installed biogas plants

a) The section 6.2.3 shows steps to calculate the net emission reduction factor for a biogas plants of size a in region b in a given period, say year 1, by

[ERF (a,b,1)]= CO_2 emissions from kerosene savings in tCO_2eq + CO_2 emissions of fuel wood savings in tCO_2eq (II) + CH_4 emissions from fuel wood savings - CH_4 leakage emissions from biogas digester and incomplete combustion in tCO_2eq (V)

Based on the monitoring results the ER factor will be adjusted every year to reflect the changes in firewood and kerosene saving for that year.

b) Determine the geographic and size distribution (in %) of the installed biogas plants

c) Determine weighted average emission reduction factor of all installed biogas plants in year 1 =ERF(w,1)

If the weighted ER factor is > 5 tCO_2/biodigester/year, apply the ER factor of 4.99 tCO_2/plant/year

If the weighted ER factor is < 5 tCO_2/biodigester/year, apply that weighted ER factor

Therefore,

Total emission reductions of the project activity in year 1 = N*P* ERF(w, 1)

Geographic and size distribution of biogas plants in the proposed project:

Table 6.3: Geographic and size distribution of biogas plants

Size of plant	Terai	Hill
4 m^3	3%	12%
6 m^3	41%	31%
8 m^3	11%	1%
10 m^3	1%	0%

1) Calculation of Standard Emission Reduction Factor per unit biogas plant

Table providing values obtained when applying formulae above:

Table 6.4: Emission Reduction Factor Calculation

Emission Reductions Unit: ton CO2 equiv.per plant

A. Fuel savings

I. Net CO2 Emission Saving from kerosene for cooking					Weighted Average
	Terai	Hill	Mountain	Average (Terai and hills)	
4 m^3	0.19	0.06	0.06	0.12	
6 m^3	0.09	0.04	0.04	0.06	
8 m^3	0.09	0.09	0.09	0.09	
10 m^3	0.06	0.07	0.07	0.06	0.07

II. Net CO2 Emission Saving from firewood for cooking

	Terai	Hill	Mountain	Average (Terai and hills)	
4 m^3	3.03	5.54	5.54	4.28	
6 m^3	7.01	7.80	7.80	7.40	
8 m^3	8.72	9.66	9.66	9.19	
10 m^3	7.19	7.58	7.58	7.39	7.20

III. Net CH4 Emission Saving from firewood

	Terai	Hill	Mountain	Average (Terai and hills)	
4 m^3	0.14	0.25	0.25	0.19	
6 m^3	0.32	0.35	0.35	0.33	
8 m^3	0.39	0.44	0.44	0.41	
10 m^3	0.32	0.34	0.34	0.33	0.32

Net Emission Reductions from Fuel Saving

	Terai	Hill	Mountain	Average (Terai and hills)	
4 m^3	3.35	5.84	5.84	4.60	
6 m^3	7.41	8.19	8.19	7.80	
8 m^3	9.20	10.18	10.18	9.69	
10 m^3	7.57	7.99	7.99	7.78	7.59

B. Project Emissions: Fugitive emissions including leakage from bigoas digester and CH4 emissions from incomplete combustion.

IV. Methane Emission

	Terai	Hill	Mountain	Average (Terai and hills)	
4 m^3	0.41	0.41	0.41	0.41	
6 m^3	0.58	0.58	0.58	0.58	
8 m^3	0.76	0.76	0.76	0.76	
10 m^3	0.96	0.96	0.96	0.96	0.58

C. Net GHG savings per digester (TCO2e/plant/year)

	Terai	Hill	Mountain	
4 m^3	2.94	5.43	5.43	
6 m^3	6.83	7.60	7.60	
8 m^3	8.45	9.42	9.42	
10 m^3	6.61	7.03	7.03	7.00

For the purpose of conservative estimation and meeting the threshold emission reduction per system for the application of the monitoring methodology defined under the small scale Methodology applicable under I.C.9(c), each biogas digester under the proposed project will claim emission reductions of only 4.99 tCO2/plant/year (this figure applies only to those plants that generate ERs exceeding 5 tCO2/plant/year).

Emission Reduction factor of the biogas plants under the proposed project (weighted according to geographic and size distribution):

6.98 tCO2e/year /plant

2) Estimation of Total Emission Reductions

Table 6.5: Estimation of Emission Reductions over 7-Year Period

Crediting Period	Plant Installation	Annual ERs tCO2e	Cumulative ERs tCO2e
1 Aug 2007- 31 July 2008	9759	46,749	46,749
1 Aug 2008- 31 July 2009		46,749	93,498
1 Aug 2009- 31 July 2010		46,749	140,247
1 Aug 2010- 31 July 2011		46,749	186,996
1 Aug 2011- 31 July 2012		46,749	233,745
1 Aug 2012- 31 July 2013		46,749	280,494
1 Aug 2013- 31 July 2014		46,749	327,243

Total estimated reductions (tonnes of CO2e) : 327,243

Total number of crediting years : 7

Annual average over the crediting period of estimated reductions (tones of CO2e): **46,749**

It is estimated that the proposed project activity will result in approximately 327,243 tons of net emission reductions over a crediting life of 7 years (2007-2014). This figure includes only those ERs that will be generated during the operation life of the biogas plants and will be further verified during the project operation.

6.3 CONSTRAINTS

6.3.1 Constraints in Investment at the Level of the National Program

Without the CDM, the biogas sector in Nepal would diminish as the donors' support shrinks. For the application of the CDM to making the biogas sector economically viable, installation of at least 200,000 biogas plants is necessary. By implementing the above approaches, all 200,000 biogas plants can gradually penetrate into rural households over a period of several years, creating "a learning by doing" opportunity to utilize the CDM funding mechanism to commercialise the biogas sector in Nepal. Making biogas plants financially accessible on a large scale while promoting and maximizing their socio-economic and carbon value would create an economic basis for future biogas sector investments. The optimisation of the technological performance through R&D and rigorous quality control would build a sound technological base. In addition, the institutional development to facilitate various functions of the biogas sector, such as financing, construction, maintenances, manufacturing, training, and marketing, would further establish the sustainability of the biogas sector.

By combining carbon revenues earned from selling the generated ERs with the remaining public donor support it will be possible to build upon the previous efforts to develop the biogas sector and transform it into a commercially viable sector. At the time of reaching the agreement to provide funding support to the fourth-phase, both KFW and DGIS/SNV fully recognized that biogas plants have a GHG mitigation potential that has a financial benefit that is achievable under the CDM, and the income from the sales of GHG emission reductions will help achieve the fourth phase target of installing 200,000 biogas plants and making the biogas program a commercially sustainable activity.

6.3.2 Constraints in Investment at the Level of Households

The high up-front investment cost of a biogas plant is a barrier for poor cash-strapped farmers in Nepal. Depending on size and location, a biogas plant costs between US $251 and $393 (Table 6.6). For a Nepali farmer, the conventional and least cost cooking technology is the traditional or improved stove burning a combination of firewood, agricultural residue, and animal manure. The conventional lighting fuel is kerosene used in small wick lamps. Tea shops and a few families living in towns or next to motorable roads where firewood is likely to be scarce use kerosene in pressure stoves for cooking in market areas. Both the traditional stove and the improved cooking stove are low-cost devices constructed from local materials. The total cost of an improved stove can range from US$3-6 and the cost of a kerosene stove ranges from US$6-8.

The high up-front investment cost of a biogas plant inhibits a poor farmer from adopting the technology, making the subsidy provided under the proposed project an essential economic incentive for farmers deciding to purchase a biogas plant. The subsidies range from $73 in the Terai to $113 in the Hills (Table 6.6). The higher levels of subsidy in the Hills and mountain areas are intended to compensate for higher costs of construction, relatively lower gas production, and less likelihood of fuelwood purchase in those locations. The subsidies are greater for $4m^3$ and $6m^3$ plants than for $8m^3$ and $10m^3$ plants. This is to encourage poorer farmers who have fewer cattle and are less likely to pay for firewood to purchase plants.

Table 6.6: Cost of biogas plants in Nepal (US$)

Size (m^3)	Location	Average Cost	Subsidy	Net Cost
4	Terai	251	73	178
4	Hill	261	113	148
6	Terai	284	73	211
6	Hill	295	113	182
8	Terai	335	67	268
8	Hill	350	107	243
10	Terai	376	67	309
10	Hill	393	107	286

Source: Winrock International 2004.

The earlier phases of the BSP-Nepal program targeted more accessible areas where a higher percentage of households purchase cooking fuel. The proposed project aims to introduce new plants in more remote communities where the majority of households would not purchase firewood in the absence of the project activity. Although the percentage is not precisely known, existing studies show that the large majority of farmers acquire firewood at no monetary expense.

Only a minority of rural Nepali households – primarily those living in market towns or next to motorable roads – purchase firewood in the market or cook with kerosene or LPG. The majority collects fuel from the closest forest. Firewood can be costly if purchased at the official government price of about US$0.02/kg of wood and a liter of kerosene costs US$ 0.60, whereas biogas has no running costs except the cost of labor to feed manure into the plant and to maintain the plant. The average annual maintenance cost of the biogas plant is about US$2.

A recent BSP-Survey reports that the Hill household using a biogas plant would purchase on average 11.5% less firewood annually compared to the amount that it would have purchased without a biogas plant and would achieve little or no benefits in terms of bio-slurry value (the remaining firewood collected at no expense). Since the bio-slurry use is a new practice in Nepal, this study also indicates that the sampled households did not have confidence in this new source of fertilizer to reduce purchase of commercial inorganic fertilizers; consequently, the households realized little financial value from the bio-slurry use. Although no survey is available for the Terai, the Terai households are expected to purchase a greater percentage of firewood, thereby potentially achieving greater savings from avoiding the firewood purchase by using a biogas plant than the households in the hills (due to the scarcity of available forest firewood). Nevertheless, given the minimal fertilizer benefits that the biogas households are realizing from the bio-slurry, it is extremely unlikely that the Terai household would realize at least 47% of fertilizer value from the bio-slurry, which is required for a profitable investment. A household that would achieve no financial value from bio-slurry use would only regard the biogas investment as profitable if it had purchased at least 95% of the amount of annually consumed firewood (which would be substituted with a biogas digester). However, this scenario, too, is unlikely since the targeted households in the project are located in remote areas and most probably will acquire firewood at no cost. This strongly indicates that the targeted farmers in both Terai and Hill would not invest in the biogas digester unless they would receive a subsidy that fills their cost gap.

The project is expected to increase fertilizer benefits of the bio-slurry for the participating households through a planned fertilizer extension program. The project through social marketing activities will further enable these households to incorporate not-yet monetized benefits of the biogas use, such as time savings and improved health through reduced indoor smoke and improved sanitation, in their investment decision. Thus, the subsidy provision along with social marketing and fertilizer extension activities under the project would provide socio-economic incentive for a farmer to buy into the biogas program.

6.3.3 Constraints in Technology

A well-known barrier for the dissemination of biogas digesters worldwide is the poor quality of biogas systems. In the absence of a proper quality control program, suppliers of biogas plants would compete solely on price. Users cannot determine the quality of biogas plants. Thus, without the proposed CDM project activity, biogas companies would have an incentive to save on costs and provide poor quality systems. The dissemination of low-quality biogas plants would lead to lack of trust in the technology, resulting in a vicious circle with less demand, fewer margins on biogas digesters sales, and more cost savings. This vicious cycle is a barrier to the successful adoption of the biogas digester technology in Nepal. Currently, in addition to the subsidy that it administers, BSP-Nepal provides quality control on all plants constructed by participating companies. In fact, it is this "carrot" and "stick" approach that result in high quality plants, which is at the heart of the success of BSP-Nepal. BSP-Nepal has built up its comprehensive system of quality control in order to make sure that high quality biogas plants are consistently produced. CDM revenues can support this quality control and assurance function of BSP-Nepal necessary to maintain the construction standard and, subsequently, the performance of the technology.

In essence, without carbon revenues, the Nepali government's program to make the biogas sector a commercially viable and market-oriented sector would be in jeopardy and would most likely not achieve its program objectives. Moreover, it is evident that the most likely development in the absence of the proposed project activity is that the households to be enrolled in the project would continue to use conventional fuels to meet their cooking energy needs. Additionally, it is most likely that they would continue disposing the manure of their cattle according to their conventional practices.

6.4 MONITORING METHODOLOGY AND PLAN

In line with the selected baseline methodology, the monitoring methodology in Annex B of the simplified M&P for small-scale CDM project activities that applies to this project is:

I.C. Thermal Energy for the User:

"If the emissions reduction per system is less than 5 tons of CO2 a year:

(1) Recording annually the number of systems operating (evidence of continuing operation, such as on-going rental/lease payments could be a substitute),

(2) Estimating the annual hours of operation of an average system, if necessary using survey methods. Annual hours of operation can be estimated from total output (e.g. tonnes of grain dried) and output per hour if an accurate value of output per hour is available.

Of important note, in the case of the BSP-Nepal project, condition 2) has been adjusted to estimating directly the reduction in conventional fuel consumption (e.g. fuel wood, kerosene), that is before and after the household installed a biogas digester, through a household survey. In the context of household biogas digesters this is a more accurate method for estimating emission reductions per system than the estimation of annual hours of operation of the biogas digester for the following reasons:

1) intensity of biogas use (high flame/low flame) can vary resulting in an unstable relation between operation hours and consumed biogas energy;
2) little is known between the direct link between hours of biogas use and reduction in conventional fuel wood consumption
3) by measuring directly the fuel consumption, the savings are corrected for any direct rebound effects (the increase in consumption of the saved fuel for other purposes).

6.4.1 Justification of the choice of the methodology

The above choice of the methodology is most suited for the proposed project for the following two reasons:

The tracking system applicable under the above proposed methodology already exists within BSP-Nepal to monitor the number and performance of all installed biogas plants. Therefore, the use of the above methodology will allow accurately monitoring and verifying the generated emission reductions and achieving costs savings necessary for the feasibility of this small-scale CDM activity. The existing monitoring system consists of the following elements:

Sales Registration and Sales Monitoring

Biogas digesters installed by eligible companies will become eligible as soon as they are registered in the BSP-Nepal database. The eligibility of biogas companies under the CDM project is based on their adherence to BSP-Nepal's quality monitoring program and end-user subsidy program. The criteria for companies to be eligible under this program are:

i. Registered as a company in the Department of Industry of Government of Nepal;
ii. Experience in biogas construction;
iii. With sufficient skilled labour force;
iv. Strong financial position;
v. Good business plan.

BSP-Nepal has registered all eligible biogas plants in an annual system installation report. The annual system installation report has been issued per Biogas Company. It provides the information necessary to determine how many biogas plants have actually been sold and constructed. Biogas Support Programme- Nepal has extensive experience in verifying the sales records of participating biogas companies.

ISO Certification & Quality Control and Assurance Monitoring

Biogas Support Programme- Nepal has been ISO-9001/2000 certified by JAS-ANZ/ICL Certifications Limited. Under this certification, BSP-Nepal is mandated to carry out quality control (QC) and quality assurance (QA) procedure as described in Section

Under quality control and quality assurance obligation, BSP-Nepal though biogas companies verifies at least 15% of all installed biogas plants over a period of three years: 5% of newly installed plants, 5% of plants installed during the previous year, and 5% of plants installed two years ago.

For emission reduction calculation and verification, BSP-Nepal should include additional indicators in its standard QA/QC monitoring.

Biogas User's Survey

Additionally, a Biogas User's Survey is annually undertaken through an independent third party consultant for evaluating the impacts of biogas installed. The survey is part of monitoring and evaluation activities of AEPC in coordination with BSP-Nepal and has included additional monitoring parameters necessary for the purpose of monitoring emission reductions.

Performance Monitoring

Under the CDM, only emission reductions that are monitored and verified can be claimed. Only those biogas households that are operating is counted toward emission reduction calculation by using the performance rate of the installed biogas plants. Through a sample survey, the number of systems out of order are determined and the performance ratio is calculated by taking the percentage of the sold biogas digesters under BSP-Nepal that are still operating.

BSP-Nepal itself or through an independent third party also occasionally verify the performance of the installed plants whenever it feels necessary for cross-checking purpose. The past performance monitoring data shows 97% performance ratio.

The list of data to be monitored is presented in tabular form on the last page of this chapter.

6.4.2 Quality Control (QC) and Quality Assurance (QA) Procedures

BSP-Nepal has prepared BSP-Nepal Quality Control Quality Manual that describes the process and the ISO clauses for the core business Quality Control. The core business quality control mechanism involves AEPC, BSP-Nepal, NBPG, recognized workshops, recognized biogas companies and biogas owners.

Main tasks of these participants are summarized below:

Biogas Owner: Biogas owner receives controller (either from BSP-Nepal, biogas company or NBPG) who checks the status of the plant, carries out final audit for after sales service. Biogas owner also receives on the spot advice if necessary.

Recognized Biogas Company: The company representative must accompany BSP-Nepal staff and NBPG staff on final product audit and receive any advice from BSP-Nepal about the function and maintenance issue. The company receives early warning every month and gets status according to the performance rating system based on the ISO-9001/2000 at the end of the construction period which is also linked to incentives.

Recognized Workshop: BSP-Nepal has an agreement with recognized biogas appliances manufacturing companies. These companies are mandated to use workshop manual that has the BSP-Nepal agreement, drawings and standards for biogas appliances. Quality control staff from BSP-Nepal go to the workshop to check if the standards are met.

AEPC and NBPG: Both of these organizations execute quality control of companies as per agreement with BSP-Nepal.

BSP-Nepal: BSP-Nepal carries out thorough quality control activities to ensure that the biogas plants are built with quality standards. This includes setting up random sampling, field visits, on the spot advice to biogas companies and biogas owners, collecting and analyzing data obtained through questionnaire during visits, sending warning reports to biogas companies every month, organizing and attending national quality review meeting, adopting "rewards or punishment" system to biogas companies etc. At least 5% of the constructed plants in any year are visited by BSP-Nepal staff for quality control. BSP-Nepal also calculates a Biogas Performance Index (BPI) (which is a composite of allocated points for Production, Average Default, Average Penalty, Average Feeding %, Accuracy, Maintenance, After Sales Service Progress) to show the status of each participating biogas company.

BSP-Nepal is ISO-9001/2000 certified by JAS-ANZ/ICL Certifications Limited. The ICL Certification Limited carries out annual surveillance audit to verify that the standards and procedures mentioned in the BSP-Nepal Quality Control Quality Manual are still maintained in accordance with ISO 9001:2000. The key elements of ISO verification include management commitment for customer and quality policy; review of management focusing on planning, responsibility, authority & communication; provision for resources; human resources; infrastructure; work environment; planning of product realization; purchasing; production and service provision; monitoring and measurement; data collection and analysis etc. One main component of this audit is to confirm if review, verification and validation of design and development have been performed and if any changes in design and development are controlled. The audit also focuses on monitoring and measurement of customer satisfaction, internal audit, monitoring and measurements of processes and products, control of nonconforming product, actions for preventive as well as corrective measures. This thorough process already encompasses required activities for CDM monitoring and thus no separate monitoring would be required.

6.5 ENVIRONNEMENTAL IMPACTS

An Integrated Environmental Impact Assessment (EIA) of biogas digester has been executed by BSP-Nepal, including health, socio-economic and gender analysis. The study concluded a net positive benefit from the use of biogas digester on socio-economic and health conditions of the biogas households and on local environment. While no adverse environmental impacts were identified, some concerns were raised with relation to the presence of pathogens in the residual bio-slurry and increased incidence of mosquitoes in the biogas households.

Studies were undertaken to address the pathogen and mosquito concerns. The study on the presence of pathogens in the bio-slurry indicates the presence of some forms of pathogens but confirms the absence of any fatal bacteria like Salmonella typhi and Vibrio Cholarate -01 in all the samples of the residual bio-slurry. Similarly, the study on mosquito breeding detected no direct link between the mosquito breeding and the biogas plant operation.

Nevertheless, an Environmental Mitigation Plan which is given below has been developed to mitigate any possible impacts from the biogas use.

Table 6.7: Environmental Mitigation Plan

1. HEALTH AND SANITATION				
Parameter	Indicators	Method	Schedule	Mitigation Plan
1.1 Latrine Construction	-Self-motivated HHs to build latrines -Motivation by Biogas Company	Interview with users and non-users of biogas and construction and maintenance reports.	Biogas Users Survey is conducted every year and finalize by June.	BSP-N will advise the farmers to connect toilets showing the benefits of sanitation improvement.
1.2 Health Aspects of Digested Sludge, with plans to overcome the existence of pathogens in slurry especially from Latrine-attached Plants	Detection of worm, protozoa and pathogenic bacteria such as Salmonellas, E. Coliform, etc	Analyze randomly selected slurry and compost samples (100) for pathogens.	BSP-N has conducted a study on the presence of pathogen in slurry. It has shown presence of some pathogens.	Proper handling of sludge and hand washing will be included in the user's training manual. Research by R&D unit is in the pipeline for the increase in retention time for the full digestion of the dung. Monitoring of diseases to be done through annual Biogas User survey.
1.3 Mosquito control (where required)	Places where mosquitoes occur frequently Causes of mosquito breeding	A device was developed and tested in 40 households. it was discovered that mosquito breeding is not due to the biogas. If farmers feel it is due to the biogas installation of the device is recommended.	Mosquito breeding research report is available and Biogas Users Survey to be conducted every year.	Provide siphon or flip, low cost mosquito control devices, to farmers on request. BSP-N will provide the farmers instructions related to clean environment and mosquito control.
1.4 Possible Gas Leakage	Assess gas leakage from biogas plants (e.g. from	Random sampling of the plants	During the course of preparing baseline,	Proper instruction and training will be provided to

	dome, pipefitting, burners, lamps, etc).		Winrock has conducted a study on gas leakage. A follow up study will be carried out in 2006.	company technicians while installing pipes. BSP-N will inform the farmers and apprise them regarding the leakage in the outlet.
2. LAND USE AND LIVESTOCK RELATED ISSUES				
2.1 Water Availability and Consumption	Source of water Distance traveled to fetch water Water required to mix with cow dung for feeding the bio-digester Water required for consumption by cattle	Interview with users and non-users of biogas	Biogas Users Survey to be conducted every year.	Training manuals with information on proper feeding of dung and water will be provided to farmers. Farmers will not be allowed to have standing water to accumulate for more than two days in the digester.
2.2 Bio-slurry as Fish Meal	Use of digested slurry as fish meal (pilots only –increased use subject to more in-depth environmental analysis)	Conduction of Field Experimentation on Fish with bio-slurry	Experimentation Completed. Report available with BSP-N	A follow up study will be done on the quality of water due to residual bioslurry in the fish pond and the effect on recipients on the d/s.

6.6 STAKEHOLDERS' COMMENTS

Biogas digesters are sold to small-scale farmers (households) throughout Nepal. Stakeholder consultation in the context of a consumer technology like a biogas digester is automatically built into the commercial sales process. Farmer "buy-in" regarding the biogas benefits is the key to selling of a biogas plant. By paying a considerable amount for its biogas digester (in the range of US$ 148 to 309), the household appreciates the value of the biogas plant. Households will also be required to sign a contract in which they transfer their emission reduction rights and all other rights associated with CDM participation to AEPC in exchange for after-sales support, subsidy and quality control. As part of this process, BSP-Nepal will inform households about the CDM and the international climate change process.

Because of the household nature of the biogas installation, no known government regulatory requirement exists concerning the consultation process. Nevertheless, consultations were undertaken with biogas users and non-users in two districts in the Terai (Dhanusha) and Hills (Baglung) regions during 17-20 and 22-25 May, 2005. The consultations process involved detailed household survey of randomly selected both biogas users and non-users of the selected Village Development Committees (VDCs) representing the major ethnic/caste groups of the two sample districts, focus group discussion with potential biogas users, and key informants interviews of knowledgeable persons contacted during the visits.

6.6.1 End-User Satisfaction

The results of the end-users surveys show a high satisfaction rate. The above findings agree with several studies carried out in the past by BSP-Nepal that revealed the users' satisfaction percentage ranging from 94 to 98%. Among other factors, the users' satisfaction is dependent upon the performance of their plants followed by quality of the after sales-services received by them.

As part of market development, the biogas companies informally contact and consult with local NGOs working in the areas related to biogas to help explain the benefits of the bio-gas plants to the local population and mobilize their participation in the program. One such local NGO, for example, esource Management & Rural Empowerment Center (REMREC), works in rural water and sanitation, and cooperates with the local company working in the same area to promote biogas plants.

6.6.2 Feedback Mechanism

End-user satisfaction is the ultimate goal of the BSP-Nepal to provide sustainability to the biogas sector. Key to achieving this goal is the continuous consultation with all concerned stakeholders to receive feedback that directly feeds into maintaining and improving the quality of the biogas sector.

The quality control program includes a number of mechanisms through which feedback from end users is sought and fed into the BSP-Nepal to ensure further optimization of the program. They include:

Quality Control Monitoring: BSP-Nepal executes an extensive quality control system of biogas digesters to ensure the interests of households. The result obtained form the quality control monitoring is linked to the payment of bonuses/penalties to the participating biogas companies. Through the system that checks numerous indicators to measure the performance of the company, BSP-Nepal ranks these companies from good to bad. This provides an incentive for these companies to improve the performance of their systems. If a company performs poorly, then the BSP-Nepal provides additional training to aid the company to improve its service quality and strengthen its business operations.

After-Sales Service: In order to participate in the Program biogas companies are obliged to provide free-after-sales service to the end-users for the first 3 years. This provides end-users with the guarantee that possible construction and material defects in the biogas plant will be repaired. By monitoring the after-sales activities of biogas companies BSP-Nepal gets direct feedback on the quality of systems delivered, which feed into determining the performance of the biogas companies.

Annual End-User Survey: Since 1992-1993 end-user satisfaction has been monitored via an annual household survey executed by independent external researchers. Using the findings and recommendations of the study, BSP-Nepal in conjunction with biogas companies undertake new activities or simply improve the existing ones to strengthen the quality of the biogas sector.

Plant Verification Studies:

Plant verification studies are in-depth studies of a district in which all biogas plants within the district are interviewed to verify their performance, assess user satisfaction and learn from end-use feedback.

Local government authorities in collaboration with BSP-Nepal carry out these studies.

Data to be monitored:

ID	Data type	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	For how long is archived data to be kept?	Comment	Responsible Authority
1	Sales registration	Registration of sales	M	continuous	100%	Electronic	Until 2 years after the last issuance of ERs for this project activity	Data is annually reported in the annual installation report	BSP-Nepal in coordination with Biogas Companies
2	Sales monitoring	Verification of installation	M on basis of a sample	Annually	15% (5% of each generation for 3 years)	Electronic	Until 2 years after the last issuance of ERs for this project activity	Data will be aggregated monthly and yearly as part of ISO Verification for quality control and assurance	BSP-Nepal in coordination with Biogas Companies
3	Performance monitoring	Performance ratio	(m) + (c) + (e)	Annually	Statistically significant sample will be chosen and adopted	Electronic and paper	Until 2 years after the last issuance of ERs for this project activity	For first 3-years of the installation, data is collected as part of ISO Monitoring and Verification for quality control and assurance and beyond 3-years, as part of the Annual Users' Survey	BSP-Nepal
5	Reduction in kerosene used for cooking	Litre	(m) + (c) + (e)	Annually	Statistically significant sample will be chosen and adopted	Electronic and paper	Until 2 years after the last issuance of ERs for this project activity	Same as before	BSP-Nepal
6	Reduction in firewood used for cooking	Kg	(m) + (c) + (e)	Annually	Statistically significant sample will be chosen and adopted	Electronic and paper	Until 2 years after the last issuance of ERs for this project activity	Same as before	BSP-Nepal
5	Accessibility to sustainable biomass		(m) + (c) + (e)	Annually	Same as before	Electronic and paper	Until 2 years after the last issuance of ERs for this project activity	Same as before	BSP-Nepal

CHAPTER-7
PREPARATION OF PROJECT DESIGN DOCUMENT OF MICRO HYDRO VILLAGE ELECTRIFICATION CDM PROJECT

This chapter simulates preparation of Project Design Document (PDD) in accordance with approved format specified by UNFCCC Executive Board. The example pertains to Micro Hydro Village Electrification Project in Nepal. The data for preparation of PDD has been obtained from Rural Energy Development Programme office in Kathmandu (Nepal). The section heading and numbering of sections has been kept same as required in the approved format.

A. General description of the small scale project activity

A.1 Title of the project activity:

Micro Hydro Villages Electrification CDM Project, Nepal

A.2. Description of the small scale project activity:

The purpose of the "Micro Hydro Village Electrification CDM Project" is to reduce GHG emissions and to contribute to the sustainable development of the rural villages by constructing micro hydroelectric power stations with a total power generation capacity of 2556 kW in the some unelectrified rural villages of 25 districts of Nepal which are off grid locations.

Plans to provide the power grid extension in unelectrified remote locations are not feasible taking into account the geographical conditions remote hilly villages characterized with high mountains of various altitudes as well as the cost efficiency. Therefore, the development of micro hydropower is essential for electrification of these remote locations.

The electrification of these villages with micro hydropower leads to the reduction of greenhouse gases emitted from the burning of fossil fuel (kerosene) and natural woods. The baseline scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of this project activity is to electrify the village by diesel power generation. Therefore, it is assumed that the electrification of these villages with hydropower will reduce the greenhouse gas emission from the diesel power generation.

In this project, hot water is planned to be provided for the villagers of these villages by using the surplus electricity which will be generated because of a little demand at the first stage of the electrification. The villagers welcome using the hot water for washing and bathing because it will reduce the load of housework and increase welfare as well as this initiative is expected to reduce dependence on fuelwood for heating water.

In addition, the communication equipment is scheduled to be set up for the remote monitoring of generated electricity, the education and the revitalization of local economies. This project contributes to improve the villager's health and daily convenience.

This project contributes not only to reduce the greenhouse gas emissions but also to sustainable development of the remote villages because of many positive effects shown in Table-1. Implementing this project well accords with the purpose of CDM.

Table-1. Benefits from the Micro Hydro Village Electrification CDM Project

Health	Being able to use electric cooking appliances (reduction in smoke inhalation from fuelwood and kerosene) Spending sanitary and healthy life by easy access to washing and bathing
Agricultural productivity	Spending less time on gathering fuelwood and food preparation, which lead to the increase of time allocated to farm work
Economic Development	Allowing more time particularly for women for farm work and/or other income generation works (cottage industries, small enterprises) through the usage of lighting and electric appliances Carrying out E-commerce by internet
Education	Enhancing introduction of new electricity-driven learning tools (television, computers, etc.) and lighting, which enables adult education during the evening hours. Receiving education through satellite broadcasting
Medical	Enabling to use vaccine refrigerators, tele-medicine capabilities, and other electric medical devices
Environment	Decreasing deforestation, land erosion by reducing fuelwood consumption Decreasing emissions from baseline diesel power generation and fuel transportation
Demographics / long-term	Decreasing infant mortality rate, increasing life-expectancy, and diminishing migration to urban areas, etc.

By linking rural electrification with rural economic activities the programme ultimately impact positively on livelihood of the rural people. Produced electricity is used for lighting and cooking. In addition it is used to operate small scale cottage industries like water mills, grain mills and others. Additional income earns from these industries uplift livelihoods of rural households.

A.3. Project participants:

This project is conducted by Rural Energy Developemet Programme (REDP) funded by a Government of Nepal (GoN), the United Nations Development Programme (UNDP) and the World Bank. It complements the rural electrification objective of the Tenth Five Year Plan (2002-2007). Government of Nepal by promoting micro hydro schemes, solar, wind energy and biogas technologies. It adopts holistic approach by linking rural electrification with rural economic activities and ultimately impact positively on livelihood of the rural people. It is targeted to cover 150 VDCs in the 25 programme districts.

Alternative Energy Promotion Center (AEPC), under Ministry of Environment, Science and Technology (MoEST) is the executing agency for the programme. Programme Management Committee (PMC) is formulated that comprise of the representatives from National Planning Commission (NPC), Ministry of Local Development (MoLD), District Energy Network (DENET), ADDCN (Association of District Development Committee of Nepal) and National Association of VDCs in Nepal (NAVIN).

A.4. Technical description of the small scale project activity:

A.4.1. Location of the small scale project activity:

A.4.1.1 Host country Party(ies):

Kingdom of Nepal

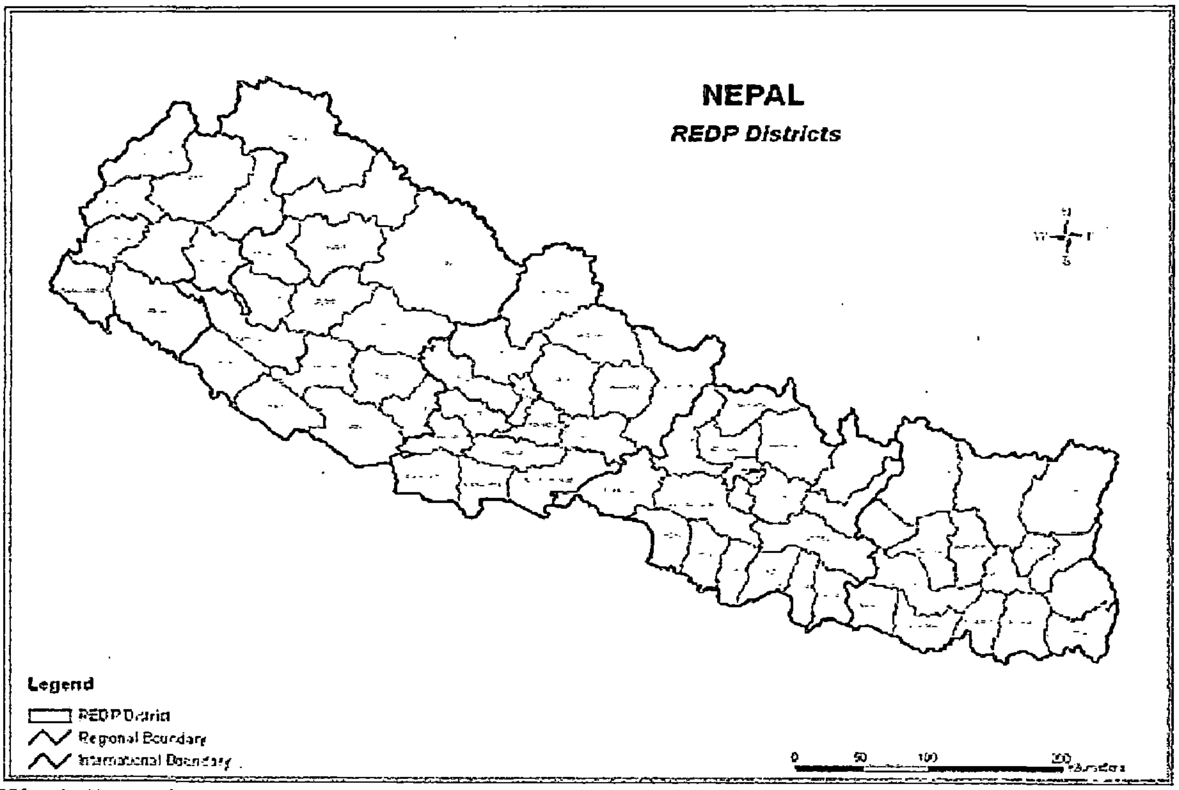


Fig 1. Locations of Microhydro Village Electrification Districts

A.4.1.2 Region/State/Province etc.:

The micro hydropower plants will be installed at various locations of 25 remote hill districts of Nepal. The geographic location of micro hydropower projects with date of commissioning and installed capacity with benefited households is given in annex-3.

A.4.1.3 City/Town/Community etc:

The micro hydropower plants will be installed at various locations of 25 remote hill districts of Nepal. The geographic location of micro hydropower projects with date of commissioning and installed capacity with benefited households is given in annex-3.

A.4.1.4 Detailed description of the physical location, including information allowing the unique identification of this project activity *(max one page)*:

People in the unelectrified villages are using firewood for cooking and heating, and kerosene for lighting. A lot of major towns in Nepal have already been electrified and people living there can use lighting appliances, rice cookers, TVs and so on. People living in the proposed project areas, on the other hand, are eager to carry out electrification of their village in order to use electrical appliances. It is considered that the electrification of the village promotes to reduce the housework of women, improve health condition of village people and to expand studying and social activity time at night etc.

A.4.2 Type and category(ies) and technology of small scale project activity

Type and Category of project activity

Type I- Renewable Energy Projects

I.A. Electricity Generation by the User

This project electrifies the non-electrified villages of 25 districts of Nepal, which has not been connected to the power grid and is not planning to connect to the power grid in the near future, by constructing hydro power (categorized under renewable energy) station. Hence, this project is considered to be classified under the Category IA.

Technologies of project activity

The micro hydro power stations are constructed to electrify remote locations in response to the increasing desire for the electrification among the villagers of the villages of 25 selected districts. Considering the potential electricity demand for the village and capable amount of the river flow used effectively for the hydro power station, it was decided to design output capacity to be 2556 KW, which clears the 15MW criteria for the Small Scale CDM project.

(Electric power generation technology)

Based on a major premise that the hydro power station is mainly operated by local people and cost-effectiveness of each type of turbines, both cross flow turbines and reversible pump turbines are two good candidates for this project. Those two turbines have characteristics of relatively simple structures, easy operation and maintenance. Taking into account of these advantageous engineering aspects of easy operation and maintenance, which have been generally learned and experienced through installation in Nepal, the cross flow turbines is selected in these projects.

(Transmission and distribution line)

Two transmission/distribution lines will be installed from the power house to village. Generated power is directly distributed to villages as the same voltage at the outlet of the generator through the single circuit of the 230V/400V three-phase four-wire type.

The power will be distributed to each facility and household via the single-phase 230V branch line that is diverged from the distribution line. A watt-hour meter will be provided to each facility and household to measure the consumed electric energy.

Taking into account durability of wood and other factors, we decided to use steel spliced pole in this project. Regarding the electric wires, the stranded type steel cored aluminum bare conductor, or Aluminum Conductor Steel Reinforced (ACSR), which is common in Nepal will be used for the 11kV transmission line. For the 230/400V distribution line, taking into account the request from the Nepal government in view of environmental protection, insulated strand cable, or Aerial Bundled Conductor (ABC), will be used.

(Operation and maintenance)

One villager from the each Village will be employed as a local operator of power plant, who is fully in the responsible for the operation including routine operation, monitoring of the electric power generated, patrol and inspections at the micro hydropower station. The selected person will be fully responsible for the operation of the power station after going through professional education by the REDP. The local operator will check deposits in the weir and settling basin, and clean up the dust screen as and when necessary. The operator will also conduct a visual check of the entire penstock monthly. In addition, he or she will clean up settled sediments as necessary to facilitate smooth operation of the power station.

In case of any accidents or troubles, that will interrupt normal operation of the power station, the local operator will take first-aid actions while immediately requesting the AEPC to repair and modify the troubled part. The AEPC will subsequently send repair engineers and necessary parts later to recover the part.

(Information and Communication Technology)

This project intends to utilize the micro hydropower station not only for the electrification program for remote locations but also for Information and Communication Technology (ICT) implementation for the purposes of education, tele-medicines, internet communications, and small enterprises development (e-commerce). ICT equipment are expected to be installed and transferred to villagers in this project.

A.4.3 Brief statement on how anthropogenic emissions of greenhouse gases (GHGs) by sources are to be reduced by the proposed CDM project activity:

This project is to construct a run-of-river micro hydro power station newly, which does not emit GHG.

The electrification of the villages is not included in "10th Five Year Plan (2002- 2007) of Nepal". Because of its geological severeness, difficulties in access, and lack of domestic resources for investments in national projects, it is very difficult to invest and construct small-scale hydro power stations in local remote areas by the Government of Nepal. Therefore, in almost all of the villages, which have already constructed small-scale hydro power stations, the constructions have been supported by various kinds of foreign official assistance. These realities demonstrate that the small-scale hydropower project is not profitable and feasible in the villages and it would not be electrified without this project. This project activity would not have occurred anyway because this project is not financially viable without REDP finance for the purpose of implementing CDM project and acquiring credits.

The baseline scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of this project activity is to electrify the village by diesel power generation. Electrification by the diesel power generation is a method generally used by the remote electrification project and is cited as an appropriate method in the "Appendix B of the simplified modalities and procedures for small-scale CDM project activities."

Since the newly built run-of-river micro hydropower generation emits no GHGs, all GHGs which would have been emitted from the diesel power generation can be considered to be reduced. A default value of CO2 emission coefficient from diesel generation units is 0.9kg- CO2/kWh, which is cited in the "Appendix B of the simplified modalities and procedures for small-scale CDM project activities." Based on an assumption that the capacity factor of the hydroelectric power station is 95%, which is calculated based on the operation hours that excludes maintenance periods, annual total electric power produced adds up to 20856.96 MWh. Therefore, the amount of emission reduction becomes 18771.26 t-CO2/year.

A.4.4 Public funding of the project activity:

Public funding, such as grants from official development funds, are not involved in this project.

A.4.5 Confirmation that the small-scale project activity is not a debundled component of a larger project activity:

The proposed project is not a debundled component of the Micro Hydro Village Electrification CDM Project according to the "debundling" rules specified in Appendix C of the simplified M&P for small-scale CDM project activities.

According to the rules, a small-scale project is a debundled component of a larger project if there is a registered small-scale activity or an application to register another small-scale activity:

With the same participants;

- In the same project category and technology/measure;
- Registered within the previous 2 years; and
- Whose project boundary is within 1 km of the project boundary of the proposed small-scale activity at the closest point.

The project participants of the proposed project are different from the project participants of another similar sub-project under REDP that has an application to be registered as a small activity, thereby clearly demonstrating that the project is not a debundled component.

B. Baseline methodology

B.1 Title and reference of the project category applicable to the project activity:

TYPE I – Renewable energy project

I.A. Electricity generation by the user

Energy Baseline (b) Option 2

B.2 Project category applicable to the project activity:

This project electrifies the non-electrified villages, which have not been connected to the power grid, by constructing a hydro power (categorized under renewable energy) station. Hence, this project is considered to be categorized under the "Category IA."

In this project, electricity is not generated at each household but only in the hydroelectric power plant. Therefore, option 2 is selected and used.

B.3 Description of how the anthropogenic GHG emissions by sources are reduced below those that would have occurred in the absence of the proposed CDM project activity *(i.e. explanation of how and why this project is additional and therefore not identical with the baseline scenario)*

The electrification of the villages is not included in "10th Five Year Plan (2002-2007) of Nepal". Because of its geological severeness, difficulties in access, and lack of domestic resources for investments in national projects, it is very difficult to invest and construct small scale hydro power stations in local remote areas by the Government of Nepal. Therefore, in almost all of the villages, which have already constructed small-scale hydro power stations, the constructions have been supported by various kinds of foreign official assistance. These realities demonstrate that the small-scale hydropower project is not profitable and feasible in the village and it would not be electrified without this project. This project activity would not have occurred anyway because this project is not financially viable without REDP finance for the purpose of implementing CDM project and acquiring credits.

The energy baseline scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of this project activity is to electrify the village by diesel power generation. Electrification by the diesel power generation is a method generally used by the remote electrification project since its initial construction cost is low, installation is easy, and operation requires no special expertise. It is also cited as an appropriate method in the "Appendix B of the simplified modalities and procedures for small-scale CDM project activities."

Because the newly built hydropower generation of the run-of-river type does not emit greenhouse gases at all, it can be considered that all greenhouse gases emitted from the diesel power generation can be reduced.

As the renewable energy technology in this project is not equipment transferred from another activity, leakage calculation is not required.

B.4 Description of the project boundary for the project activity:

"Appendix B of the simplified modalities and procedures for small-scale CDM project activities." shows the definition of the project boundary as "*The physical,* *geographical site of the generating unit and the equipment that uses the electricity produced delineates the project boundary".*

According to this definition, the project boundary is set to 'the generating unit' such as the main building of the newly installed hydro power station, water intake, penstock, the transmission/distribution equipment, and 'the equipment that uses the electricity produced' such as the hot water supply equipment as a settlement for community.

B.5 Details of the baseline and its development:

B.5.1 Specify the baseline for the proposed project activity using a methodology specified in the applicable project category for small-scale CDM project activities contained in appendix B of the simplified M&P for small-scale CDM project activities:

If this project does not exist, considering initial construction cost and easiness of its installation and operation as a remote electrification project, electrification by the diesel can be considered to occur. Since this newly built run-of-river micro hydropower generation does not emit GHGs in operating, GHGs would have been emitted by the assumingly set up diesel power generation without this project. Amount of GHGs emission from the diesel power generation is calculated with using a default value of CO2 emission coefficient from diesel power generation units, 0.9kg-CO2/kWh.

B.5.2 Date of completing the final draft of this baseline section *(DD/MM/YYYY)*:

30/06/2007

B.5.3 Name of person/entity determining the baseline:

Pradip Kumar Sah

Trainee Officer (50th Batch)

WRD&M, IIT Roorkee

C. Duration of the project activity and crediting period

C.1 Duration of the project activity:

C.1.1 Starting date of the project activity:

June 16, 2008 (for example)

Operation of the station is planned to start on May 2008. CER is to be issued in 2009 and afterwards.

C.1.2 Expected operational lifetime of the project activity: ***(in years and months, e.g. two years and four months would be shown as: 2y-4m.)***

21 year

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

C.2.1 Renewable crediting period ***(at most seven (7) years per crediting period)***

C.2.1.1 Starting date of the first crediting period *(DD/MM/YYYY)*:

01/08/2009 (for example)

C.2.1.2 Length of the first crediting period *(in years and months, e.g. two years and four months would be shown as: 2y-4m.)*:

7 year

C.2.2 Fixed crediting period ***(at most ten (10) years)*****:**

Not applicable

C.2.2.1 Starting date *(DD/MM/YYYY)*:

C.2.2.2 Length (max 10 years): *(in years and months, e.g. two years and four months would be shown as: 2y-4m.)*

N/A

D. Monitoring methodology and plan

D.1 Name and reference of approved methodology applied to the project activity:

Type IA

Monitoring (b)

"Metering the electricity generated by all systems or a sample thereof"

The monitoring method of this project is based on the method articulated in the "Appendix B of the simplified modalities and procedures for small-scale CDM project activities".

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

Since these projects are newly built run-of-river micro hydropower generation, there occurs no emissions of greenhouse gases through its operation by nature.

For the monitoring, the data of total amount of power produced by the plant as gross power output will be monitored. Since the amount of the electric power which is used for the generation equipment, power supply for the gauge, is negligible (less than 1%), it is sufficient to collect data of gross output.

In collecting data of the electricity produced for the monitoring at the power station, using watt-hour-meters is the most appropriate method to meet the requirement of accuracy, comparability, completeness, and validity.

The data monitored will be recorded on papers per day and the data consolidated after every month will be reported to REDP via the Local Community per month by the local operator. The operator is to receive appropriate education necessary for the monitoring before the start of the operation of the plant. REDP will also supervise the monitoring of the data of the power produced by the plant during the first 2 years after the start of its operation.

The watt-hour-meters used for the monitoring in this project is the same type of the meters which have been generally used at power stations in Nepal. NEA will implement the maintenance and correction of meters periodically in the same way as carried out at other hydropower plants in Nepal. The NEA has already implemented the maintenance and correction at power plants in Nepal and therefore has enough knowledge and experiences regarding the maintenance and correction of the meters.

In case of any accidents or troubles, the NEA will repair and fix the troubled part promptly.

In addition, it is planned to set up communication equipment that can monitor data concerning power generation of the plant site at remote place, and the plant operational condition will be also confirmed by checking these data.

D.3 Data to be monitored:

ID number	Data type	Data unit	Measured (m), calculated (c) or estimated (e)	Recording Frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	For how long is archived data to be kept?
1.	Electricity Generated (Gross)	kWh	m	Once in a day by hand/ electronic	100%	Paper/ electronic	9 years

D.4 Name of person/entity determining the monitoring methodology:

Pradip Kumar Sah
Trainee Officer (50th Batch)
WRD&M, IIT Roorkee,

E. Calculation of GHG emission reductions by sources

E.1 Formulae used:

E.1.1 Selected formulae as provided in appendix B:

The baseline scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the project activity is to construct the diesel power station, which is cited as reasonable in the "Appendix B of the simplified modalities and procedures for small-scale CDM project activities."

TYPE IA

(b) Option 2:

$EB = \sum_i O_i/(1-l)$

Where

EB = annual energy baseline in kWh per year

∑i = the sum over the group of "i" renewable energy technologies (e.g. solar home systems, solar pumps) implemented as part of the project.

Oi = the estimated annual output of the renewable energy technologies of the group of "i"

renewable energy technologies installed (in kWh per year)

l = average technical distribution losses that would have been observed in diesel powered

mini-grids installed by public programmes or distribution companies in isolated areas, expressed as a fraction.

Since ***Oi*** is the data of total amount of power produced by the plant as gross power output will be monitored, ***l*** is calculated as "***l = 0***". This leads to conservative calculation.

Since the run-of-river micro hydropower generation emits no GHGs, all GHGs emitted from the diesel power generation which would have been installed without this project, can be considered to be reduced. As suggested in the "Appendix B," IPCC default value from diesel generation units, or 0.9kg-CO2/kWh (Type IA), is used for the calculation of baseline emission.

As the renewable energy technology in this project is not equipment transferred from another activity, leakage calculation is not required.

E.1.2 Description of formulae when not provided in appendix B:

E.1.2.1 Describe the formulae used to estimate anthropogenic emissions by sources of GHGs due to the project activity within the project boundary: *(for each gas, source, formulae/algorithm, emissions in units of CO2 equivalent)*

Not Applicable

E.1.2.2 Describe the formulae used to estimate leakage due to the project activity, where required, for the applicable project category in appendix B of the simplified modalities and procedures for small-scale CDM project activities *(for each gas, source, formulae/ algorithm, emissions in units of CO2 equivalent)*

Not Applicable

E.1.2.3 The sum of E.1.2.1 and E.1.2.2 represents the project activity emissions:

Not Applicable

E.1.2.4 Describe the formulae used to estimate the anthropogenic emissions by sources of GHG's in the baseline using the baseline methodology for the applicable project category in appendix B of the simplified modalities and procedures for small-scale CDM project activities: *(for each gas, source, formulae/ algorithm, emissions in units of CO2 equivalent)*

Not Applicable

E.1.2.5 Difference between E.1.2.4 and E.1.2.3 represents the emission reductions due to the project activity during a given period:

Not Applicable

E.2 Table providing values obtained when applying formulae above:

	Electricity	Emission Factor	CO2 Emission Reduction
Ex-ante	20856.96 MWh	0.9	18771.26 t-CO2
Ex-post	Data to be monitored	0.9	Calculated according to the data monitored

Based on an assumption that the capacity factor of the hydroelectric power station is 95%, which is calculated based on the operation hours that excludes maintenance periods and periods which have not enough water for generation, annual total electric power produced adds up to 20856.96 MWh(E_B =20856.96MWh/year). Amount of CO2 emission reduction which is calculated according to annual total electric power produced multiplied by IPCC
default value of the diesel generation units, or 0.9kg-CO2/kWh, is 18771.26t-CO2 per year.

(20856.96MWh/year x 0.9 kg-CO2/kWh =18771.26t-CO2/year)

The actual GHG emission reduction is calculated by using *Ex-post* data monitored. Since annual total electric power produced by the hydroelectric power fluctuates according to annual precipitation of each year, it is more accurate to use *Ex-post* data monitored for the calculation.

F. Environmental impacts

F.1 If required by the host Party, documentation on the analysis of the environmental impacts of the project activity: *(if applicable, please provide a short summary and attach documentation)*

National Environmental Guidelines 1993 and Environmental Protection Regulation 1997 do not make Environmental Impact Assessment (EIA) mandatory for micro hydro projects in Nepal. However, REDP undertakes EIA of all micro hydro projects that are proposed for implementation in its programme areas.

Although the environmental impact caused by the installation of the hydropower station can be considered to be limited, REDP is planning to implement the following activities as monitoring periodically during the first 2 years after the construction of the power station.

- Measurement of the water flow at the intake on the river;
- Analysis of the socio economic condition of the villagers after the electrification;
- Analysis of the impact of the flow reduction upon the presence of brown trout's.

G. Stakeholders comments

G.1 Brief description of the process by which comments by local stakeholders have been invited and compiled:

Not Applicable

G.2 Summary of the comments received:

Not Applicable

Annex-1

CONTACT INFORMATION FOR PARTICIPANTS IN THE PROJECT ACTIVITY

(Contact Person of Host Country)

Organization:	
Street/P.O.Box:	
Building:	
City:	
State/Region:	
Postfix/ZIP:	
Country:	
Telephone:	
FAX:	
E-Mail:	
URL:	
Title:	
Salutation:	
Last Name:	
Middle Name:	
First Name:	
Department:	
Mobile:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	

(Contact Person of Host Country)

Organization:	
Street/P.O.Box:	
Building:	
City:	
State/Region:	
Postfix/ZIP:	
Country:	
Telephone:	
FAX:	
E-Mail:	
URL:	
Title:	
Salutation:	
Last Name:	
Middle Name:	
First Name:	
Department:	
Mobile:	
Direct FAX:	
Direct Tel:	
Personal E-Mail:	

(Contact Person of Host Country)

Organization:	Community Development Carbon Fund (CDCF), New Carbon Funds Team, The World Bank.
Street/P.O.Box:	1818 H Street, NW
Building:	MC4-414
City:	Washington DC
State/Region:	
Postfix/ZIP:	20433
Country:	USA
Telephone:	202 473 6010
FAX:	
E-Mail:	cfcontacts@worldbank.org
URL:	www.communitycarbonfund.org
Represented by:	
Title:	
Salutation:	
Last Name:	
Middle Name:	
First Name:	
Department:	
Mobile:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	
Organization:	
Street/P.O.Box:	
Building:	
City:	

Annex-2

INFORMATION REGARDING PUBLIC FUNDING

Public funding, such as grants from official development funds, are not involved in this project. Hence Annex 2 is not relevant.

Annex-3

Rural Energy Development Programme

Status of Micro Hydro Village Electrification CDM Projects

(As of Marg.2063/64- Dec.2006)

S.N.	Schemes	Initiation of CM Process	Location (VDC)	Power Output (KW)	Beneficiary HH
Eastern Dev. Region				**624**	**4702**
Okhaldhunga				**77**	**889**
1	Pokali Khola	Nov. 2000	Pokali	17	175
2	Thotne Khola	Nov.2005	Mamkha	22	200
3	Para Khola	Sept. 2004	Chhyanum	12	120
4	Molung Khola	Sept. 2004	Chhyanum	26	394
Solukhumbu				**205**	**736**
1	Bom Khola	Sept. 2004	Chaurikharka	100	147
2	Siku Khola II	Sept. 2004	Kangel	17	162
3	Siku Khola	Sept. 2004	Mukli	10	88
4	Hyawa Khola	Sept. 2004	Taksindu	28	248
5	Monjo Khola	Sept. 2006	Chaurikharka	50	91
Sankhuwasabha				**51**	**455**
1	Kekuwa Khola	Sept. 2004	Tamafok	21	184
2	Lakhuwa Khola	Sept. 2004	Mawadin	15	139
3	Kusuwa	Sept. 2004	Syabun	15	132
Terhathum				**111**	**1028**
1	Koya Khola	Nov. 2004	Sakranti	63	598
2	Lower Phunguwa Khola	Nov. '00	Hwaku	13	110
3	Chiwa Khola	Nov. '00	Hwaku	20	175
4	Sanduwa Khola	Jan. 2004	Srijung	15	145
Taplejung				**62**	**453**
1	Pawa Khola	Sept. 2004	Sanwa	22	243
2	Subuwa Khola	Sept. 2004	Hampang	20	210
3	Subuwa Khola II	Sept. 2006	Hampang	20	215
Panchthar				**118**	**1141**
1	Khewatham Khola	Sept. 2004	Memen	45	424

2	Thado Khola	Sept. 2004	Oyam	12	143
3	Nibu Khola	Sept. 2004	Angsarang	16	147
4	Hariridulaya Mewa Khola	Sept. 2004	Phalaincha	45	427
Central Dev. Region				**272**	**2769**
Dhading				**71**	**750**
1	Malekhu Khola	Sept. 2004	Mahadevsthan	26	265
2	Manpang Khola	Sept. 2004	Budathum	16	175
3	Kheste Khola	Sept. 2004	Baireni	9	100
4	Belkhu Khola	Sept. 2004	Kiranchaur	20	210
Kavre				**108**	**1000**
1	Chau Khola	Jul-05	Gokule	22	194
2	Pokhara Khola	Jul-00	Phoksintar	12	110
3	Chau Khola II	Oct.2002	Dandagaon	24	240
4	Banakhu Khola	Sept. 2003	Banakhu	50	456
Sindhupalchowk				**42**	**475**
1	Chhahare Khola	Jul-03	Baruwa	17	195
2	Bhumae Khola	Jul-99	Pangtang	13	162
3	Bumba Khola	Jul-00	Gumba	12	118
Dolkha				**51**	**544**
1	Punku Khola	Sept. '00	Lapilang	19	175
2	Gatte Khola	Sept. '00	Khopachngu	12	119
3	Dorung Khola	Sept. '00	Chilankha	20	250
Western Dev. Region				**575**	**5646**
Baglung				**355**	**3409**
1	Upper Girindi Khola	Nov. '05	Sisakhani	50	450
2	Darling Khola	Sep. '05	Darling	43	555
3	Upper Bhimghat Khola	June '05	Bhimgithi	42	420
4	Labdi Khola II	Jan. '05	Gwalichaur	35	307
5	Pachuwa Khola	Nov. '04	Kandebas	30	270
6	Lower Labdi Khola	March '06	Daga	25	242
7	Girindi Khola	Nov. '04	Daga	75	680
8	Narsing Kut Khola	Oct. ' 05	Darling	25	225
9	Bhalibang Khola	Oct. ' 05	Khunga	30	260
Myagdi				**115**	**1095**
1	Ruma Khola	Jan. '03	Ruma/ Nishi	60	540

2	Bhuke Khola	Sept. '98	Arman	20	210
3	Gauda Khola	Sept. 2004	Devisthan	20	205
4	Lamochhara Khola	Sept. 2004	Khun	15	140
Parvat				**59**	**657**
1	Aguwa Khola II	Jan. '01	Saraunkhola	11	146
2	Dhuwakot Khola	Jan. '04	Bhorle	16	223
3	Sibdi Khola	Jan. '04	Byaulibas	20	183
4	Gedi Khola	Jan. '04	Huwas	12	105
Tanahun				**46**	**485**
1	Wanza Khola	Sept. '99	Kotdurbar	13	118
2	Chinne Khola	Sept. 2004	Ghiring	10	120
3	Lima Khola	July '03	Kot Durbar	12	142
4	Chanp Khola	July '05		11	105
Mid - Western Dev. Region				**251**	**2533**
Humla				**65**	**640**
1	Kharpunath Khola	Sept. '04	Kharpunath	10	95
2	Hepka Khola	Sept. '04	Dandafaya	20	195
3	Raya Khola	Sept. '04	Raya	15	140
4	Rip Khola	Sept. '04	Sarkideu	20	210
Mugu				**66**	**662**
1	Luma Khola	Sept. '04	Ruga	15	155
2	Khatyad Khola	Sept. '04	Seri	20	190
3	Daro Khola	Sept. '04	Sukadhik	11	110
4	Khatyad Khola II	Sept. '04	Kotdanda	20	207
Dailekh				**75**	**788**
1	Katti Khola	Dec '03	Rum	20	200
2	Kane Khola	Dec '00	Rakam	18	200
3	gadi Khola	Dec '00	Visalla	16	160
4	Lohore Khola	Sept. '04	Baluwatar	21	228
Pyuthan				**45**	**443**
1	Gatte Khola II	July '02	Arkha	15	154
2	Susaune Khola	Sept. '04	Arkha	20	200
3	Siring Khola	Sept. '04	Rajbara	10	89
Far- Western Dev. Region				**834**	**8506**
Darchula				**87**	**846**

1	Agari Gad	Jan. '05	Gokuleshwor	25	250
2	Kala Gad	Jan. '05	Hikala	34	314
3	Hardi Gad	Jan. '05	Dandakot	11	110
4	Khar Gad	Jan. '05	Khar	17	172
Baitadi				**56**	**621**
1	Dhum Gad	Sept. '04	Sigas	24	240
2	Irana Gad	Sept. '04	Gajari	15	188
3	Pattharkot Gad	Sept. '04	Shikharpur	17	193
Dadeldhura				**63**	**655**
1	Rel Gad	Sept. '03	Kailpanmandu	15	205
2	Daha Gad	Feb. '04	Gangkhet	30	290
3	Tak Khola	Feb. '04	Gangkhet	18	160
Bajhang				**152**	**1535**
1	Khori Gad	Sept. '04	Lekgaon/ Byasi	45	448
2	Bhangadi Gad	Sept. '04	Majhigaon/ Kalu	20	212
3	Thalari Gad	Sept. '04	Kotbhairav	65	618
4	Sain Gad	Sept. '04	Sainpasela	22	257
Bajura				**230**	**2299**
1	Narighat Olisen Khola	Dec '00	Pandusen	65	645
2	Ikadi Gad	Dec '00	Barhabish	30	291
3	Narighat Khola II	Dec '00	Pandusen	35	350
4	Baddi Gad	Sept. '04	Kolti	100	1013
Doti				**71**	**795**
1	Saily Gad III	Sept. '04	Daud	22	284
2	Saily Gad	Sept. '04	Toleni	14	161
3	Gadseri Gad	Sept. '04	Gadsera	35	350
Achham				**175**	**1755**
1	Ardoli Gad III	June '03	Babla	52	520
2	Sarani Gad	June '03	Kuskot	27	285
3	Kasha Gad	June '03	Thanti	36	428
4	Upper Kailash Khola	March '06	Ramaroshan	60	522
			Total	2556	24156

CHAPTER-8

SUMMARY AND RECOMMENDATIONS

8.1 SUMMARY

8.1.1 Introduction

There is increasing scientific evidence of human interference with the global climate system, along with growing public concern about the environment. An international treaty on global climate protection known as the United Nations Framework Convention on Climate Change (UNFCCC) came into force on March 21, 1994. The principles of equity and "common but differentiated responsibilities" contained in the Convention were required industrialized countries (Annex I Parties) to take the lead in returning their greenhouse gas emissions to 1990 levels by the year 2000.

During 3rd Conference of Parties (COP3) in Kyoto, Japan, on 11 December 1997, a legally binding set of obligations for 38 industrialized countries and 11 countries in Central and Eastern Europe was created, to return their emissions of GHGs to an average of approximately 5.2% below their 1990 levels over the commitment period 2008-2012. This is called the Kyoto Protocol to the Convention. The Kyoto Protocol entered into force on 16 February 2005 with its ratification by Russia and to date 175 Parties have ratified the Protocol. The targets cover six main greenhouse gases. Some activities in the land-use change and forestry sector, such as afforestation and reforestation, that absorb carbon dioxide from the atmosphere, are also covered.

The Protocol establishes three cooperative mechanisms (International Emission Trading, Joint Implementation and Clean Development Mechanism) designed to help industrialized countries reduce the costs of meeting their emissions targets by achieving emission reductions at lower costs in other countries than they could domestically.

The CDM allows industrialized countries (Annex I Party) to implement a project that reduces greenhouse gas emissions or, subject to constraints, removes greenhouse gases by carbon sequestration, or "sinks," in the territory of a developing country (Non- Annex I Party). The resulting certified emission reductions (CERs), can then be used by the industrialized countries to help meet its emission reduction target.

The CDM is supervised by an Executive Board, composed of 10 members, including one representative from each of the five official UN regions (Africa, Asia, Latin America and the Caribbean, Central Eastern Europe, and OECD), one from the small island developing states, and two each from Annex I and non-Annex I Parties.

All parties (Annex I and non-Annex I Parties) must meet three basic requirements to participate in CDM: i) voluntary participation, ii) establishment of the National CDM Authority, iii) ratification of the Kyoto Protocol. Annex I Parties moreover must meet some additional requirements

The Kyoto Protocol stipulates several criteria that CDM projects must satisfy. Two critical criteria are additionality and sustainable development.

Additionality: Projects must result in "reductions in emissions that are additional to any that would occur in the absence of the project activity".

Sustainable development: There is no common guideline for the sustainable development criterion and it is up to the developing host countries to determine their own criteria and assessment process.

In order to make small projects competitive with larger ones, the Marrakech Accords establish a fast track for small-scale projects with simpler eligibility rules—renewables up to 15 MW, energy efficiency with a reduction of consumption either on the supply or the demand side of up to 15 gigawatthours/yr, and other projects that both reduce emissions and emit less than 15 kilotons of CO2 equivalent annually.

Bundling: A large number of small projects can be combined in one PDD. Projects may be bundled as long as the total size is below the limits for a single project as listed for the 3 small scale project types above.

Debundling a large CDM project into consecutive small-scale parts is not eligible for a small-scale CDM project if the total is greater than the small-scale project eligibility.

8.1.2 The CDM Project Cycle and Approval Process in India and Nepal

The CDM project cycle follows seven steps 1) Project design and formulation, 2) National approval, 3) Validation and registration, 4) Project finance, 5) Monitoring, 6) Verification/certification and 7) Issuance of CERs

All countries wishing to participate in the CDM must designate a National CDM Authority to evaluate and approve the projects, and serve as a point of contact. In India, the Ministry of Environment and Forests (MoEF), which is the nodal agency for the subject issues of climate change, was made the host of the DNA for dealing with the CDM and other climate change issues. It is responsible for developing an institutional framework for developing CDM projects in the country, as well as endorsing CDM projects. Nepal signed the United Nations Framework Convention on Climate Change (UNFCCC) on 12th June 1992 at Rio de Janeiro and ratified it on 2 May 1994, making it effective in Nepal three months later on 31st July 1994. In this connection the Ministry of Population and Environment (MOPE) with mandates for implementing the UNFCCC provisions is coordinating the activities related to the obligations. Project financing is a common and crucial part of project implementation in every project. There are multilateral and bilateral sources of funding to develop CDM projects.

Public funding for CDM projects from Parties in Annex I is not to result in the diversion of official development assistance (ODA) and is to be separate from and not counted towards the financial obligations of Parties included in Annex I

Monitoring is a systematic surveillance of a project's performance by measuring and recording target indicators relevant to the objective of the project. The project's developers should prepare a monitoring plan which is transparent, reliable and relevant.

Verification includes the periodic auditing of monitoring results, the assessment of achieved emission reductions and the assessment of the project's continued conformance with monitoring plan. Following a detailed review, an operational entity produces a verification report and then certify the amount of CERs generated by the CDM project.

Certification is a written assurance by the DOE that, during a specified time period, a project activity achieved the reductions in anthropogenic emissions by sources of GHGs as verified. The certification report shall constitute a request to the EB for issuance of CERs equal to the verified amount of reductions of anthropogenic emissions of GHGs. Unless a project participant or three Executive Board members request a review within 15 days, the Executive Board will instruct the CDM registry to issue the CERs.

The EB must issue the CERs to the project partners within 15 days after the date of receipt of the request for issuance. As early as possible in the project design negotiations, contracts (rights and obligation rules for dispute resolution) on carbon credit ownership must be made between the project participants.

8.1.3 The Procedure for Preparation of Project Design Document

In order to get a CDM project approved and registered by the Executive Board (EB), the project participants have to prepare a Project Design Document (PDD) following the detailed outline shown on the CDM website of the UNFCCC Secretariat. In order to simplify the procedures for small-scale CDM projects, the EB has proposed standardized baselines for some of the project categories.

According to the 'Modalities and Procedures for the CDM', there are two possibilities for the crediting period: 1) A period of maximum 10 years and 2) A period of maximum 7 years, with the potential for renewal for two additional periods at most.

If the host country requires an Environmental Impact Assessment (EIA), or stakeholder input shows that there are local environmental or social concerns about the initiative, a CDM project should be evaluated using the highest international environmental and social assessment procedures and standards.

The DOE doing the validation must make the project design document for the CDM project publicly available. NGOs and other stakeholders have a 30-day period to comment on the PDD and thereafter the DOE must describe how comments by stakeholders have been invited and compiled; a summary of the comments received; and a report on how due account was taken of any comments received.

8.1.4 Financing and Marketting of CDM Projects

CDM projects produce both conventional project output and carbon benefits (CERs). The value of carbon benefits and its impact on project viability are influenced by several factors such as the amount of CERs generated by the project, the price of CER and the transaction costs involved in securing CERs.

The amount of CERs generated by the project depends on the greenhouse gas displaced by the project and the crediting period selected. Renewable energy and energy efficiency projects displace carbon intensive electricity and/or heat generation. Grid-based or off-grid projects that displace more carbon intensive coal and diesel fuels generate more CERs than those that displace natural gas. Projects that capture methane and greenhouse gases other than CO2 produce more CERs since the global warming potential (GWP) of methane and other gases are several times higher than that of carbon dioxide.

The price of CERs is determined in the carbon market. At present, the carbon market is a 'loose collection of diverse transactions' where emission reductions are exchanged. There are three main markets where greenhouse gas emission reductions are traded: project based or "baseline and credit" system; allowance market or "cap and trade" system, and; voluntary market.

The net financial gain derived from the sale of CERs is the difference between the project CER value and the transaction costs. There are three elements that influence the net impact of CERs on project profitability: value of CERs (low CER value implies low net benefits), overall transaction costs (high transaction costs yield low net benefits), and up-front transaction costs (high upfront payments could also result in low benefits).

Governments and private companies from non-Annex 1 parties are the main buyers of CERs. CDM projects require upfront investments that are normally obtained from different sources such as loans, equity, grants, and upfront payments for emission reductions.

The projected demand and supply balance shows that there will be a net surplus of emissions reductions in 2010, which ranges from around 366 MMTCO2e to 1873 MMTCO2e. These surplus scenarios however will only materialize if emissions reductions supply will be freely traded in a competitive market. In reality, this will depend on the willingness of the supplying countries to issue and transfer, as well as on the receiving governments to recognize and use these emissions reductions for the Kyoto Protocol compliance.

Project-based transactions (CDM and JI) dominate the global trade of greenhouse gas emission reductions. It represented 85% of the total transaction volume in 2002, and 97% between 1996 and 2002 (PCF Plus, 2002). The total carbon market volume traded in 2001 was about 13 MMTCO2e, increasing to 29 MMTCO2e in 2002, and reaching to more than 70 MMTCO2e in the first 10 months of 2003 (PCF, 2003). Point Carbon (2004) projected that the total volume will reach 100 MMTCO2e in 2004.

The World Bank's PCF and the Dutch Government's C-ERUPT tender are the current main buyers of CERs through direct purchase transactions. Three new public-private partnership funds have been recently launched by the World Bank: the Community Development Carbon Fund, the Bio-Carbon Fund and the Italian Carbon Fund. Public-private partnership funds to purchase CERs were also established by the European Investment Bank, Japanese Banks, Germany's KfW and Ecosecurities-Standard Bank of London (Danish CDM Facility).

The fragmented nature of the global carbon market generates differentiated prices for emissions reductions. Allowance markets generate high emission reduction prices since the delivery risks are believed to be minimal. The current price spread of CERs is US$ 3 – 6 per TCO2e.

8.1.5 Clean Developemt Resources of Nepal

Nepal is a landlocked and predominantly mountainous country with a total area of 147,181 sq. km. within a mean width of 193 km.

Water is Nepal's major natural resource. The hydroelectric power potential is estimated at 83,000 megawatts, of which about 50 percent could be economically harnessed.

The population density stands at an estimated 165 persons per square km. A population growth rate of 2.3 percent per annum during 1980 – 2001 and the expected growth rate of around 2% until 2015 is putting Nepal's environmental resources under tremendous pressure.

The country is still engulfed in a vicious cycle of poverty, underdevelopment and environmental degradation with 38 percent of the population still below the poverty line at the end of the Ninth Five Year Plan in 2002.

The total energy consumption in Nepal was 8.205 million toe in 2002, which translates to per capita annual energy consumption of about 15 Giga Joule (GJ), ranks among the lowest of the world. The energy mix is lopsided in Nepal, with biomass (fuel wood, agricultural residue and animal dung) being the main energy providers, supplying an overall 88% of the total energy consumed.

Fuel wood, representing 78% of the energy consumption, is mainly used in rural Nepal. Energy end-uses of the domestic sector are mainly for cooking and lighting. The total demand of 331 million GJ in the domestic sector in 2004/05 was met mostly by fuel wood, followed by 16.2% agricultural residue.

With an estimated total energy demand of 12.7 million GJ in 2004/05, the industrial sector, at 50%, is also dominated by fuel wood. However, the share of other energy sources is also significant here. Coal and petroleum products contributed 22% and 12%. Agri. residue contributes 6% in these mostly agri. based industries.

Transportation sector is heavily dependent on imported fossil fuels. Diesel contributes 63% followed by petrol with 18%. Aviation Turbine Fuel (ATF) contributes 17% whereas the share of electricity and coal is very minimal.

About 87% Nepalese live in rural areas with agriculture as the main livelihood. Energy consumption in rural areas constitutes about 87% of the country's total energy expenditure, and the residential sector accounts for 89% of the total energy consumption. From the perspective of energy end-use, residential cooking is a single activity that accounts for about 65% of the total energy consumption.

Indigenous energy resources in Nepal consist of a combination of traditional and commercial sources including fuel wood, agricultural residue, animal waste, hydropower, solar and potentially wind energy as well. The theoretical potential of known indigenous energy sources, excluding solar energy, amounts to 1,970 million GJ annually on a sustainable basis, which indicates Nepal's potential to cover its energy requirements.

Nepal has abundance in natural resources with 224 billion cubic meters of annual run off and 300 sunny days in a year, with 6.5 hours average daily sunshine. Nepal's energy resources potential is estimated to be 1,519 million GJ annually on a sustainable basis, which would be 15 times the estimated total GJ consumption. This indicates that there is sufficient potential of energy output of renewable sources. Besides biomass, there are other renewable energy sources, like hydropower, solar, wind and biogas, with great potential in Nepal.

80 MW of electric power generation potential is anticipated from the currently existing sugar industries in Nepal, around 60 MW of which can be supplied to the national grid.

According to the Micro-hydro Yearbook of Nepal 2002, a total of 371 micro-hydro schemes with a total capacity of 5,068.2 kW and 875 peltric set units with a total capacity of 1,471.9 kW have been installed in Nepal for the purpose of rural electrification. The 10^{th} Five Year Plan has set a target of 10 MW of power generation from micro-hydro. In addition to this, there are also 800 MHP schemes with the total installed power of 7,074.9 kW for mechanical power used for milling purposes.

The potential number of biogas plants in Nepal was estimated to be about 1.9 million in 2001 by BSP out of which 57% are expected in the plains, 37% in the hills and the remaining 6% in the mountain region. BSP, however, has estimated that only around 1000,000 plants would be economically promising. Biogas is being ardently promoted by numerous organizations, there were 140,549 plants at end of Dec 2005 installed with support from BSP alone throughout the country.

The average annual household consumption of fuel wood in Nepal is about 3,666 kg. Fuel wood is primarily burnt in traditional or open fire stoves. Each rural household possesses at least one traditional and/or open fire stove. According to CBS 2001, there are 4.3 million households in the country, out of which 85% are in rural areas, i.e. about 3.6 million households. As a result, there is a high potential for ICS to reduce fuel consumption in the domestic sector.

Nepal has about 300 days of sunshine per year and the average insolation for Nepal ranges between 4 to 5 $kWh/m^2/day$. The total solar energy potential in Nepal is estimated to be about 27 million MW.

Nepal's efforts to harness wind energy has resulted in a series of failures in the past. The main lesson learnt is that thorough and reliable wind analysis has to be made before a wind power project is undertaken.

According to the World Development Report 2003, Nepal's share in the total CO_2 emissions was 3 million tons of CO_2 in 1998. The net national emissions of CO_2, CH_4 and N_2O were estimated at 9,747 Gg, 877 Gg and 30 Gg respectively for the base year 1994/95. Of the five categories included in the inventory, the Land use Change and Forestry sector, with total emissions of 22,895 Gg is the strongest source of CO_2 followed by the Energy sector with 1,465 Gg. Fossil fuel combustion in transportation, industrial, domestic, commercial and also in agricultural sectors is the major anthropogenic source of CO_2 emissions. The total CO_2 emission from fossil fuel consumption in the base year was estimated at 1465 Gg.

8.1.6 Nepal Biogas Support Programme (BSP-NEPAL) – A Case Study

Biogas digesters are being sold to households in rural areas so as to reduce GHG emissions by displacing conventionally used fuel sources such as fuelwood and kerosene. An MOU has been signed by Alternative Energy Promotion Centre (Nepal) and World Bank for trading of GHG emission reduction equivalent to 1 million tons of CO_2 through two small scale CDM projects of BSP over 7 years. Total installed equivalent generation capacity is 14.77 MW, so it falls under small scale CDM project category.

A total of 9759 biogas plants distributed over 55 districts have been installed during April 7, 2005 to December 2005. Each biogas household is the participant of the project who decides to invest in a biogas plant and owns emission reductions generated thereafter. Biogas will meet thermal energy needs of households with at least two heads of cattle (cow or buffalo) and will displace firewood and kerosene (fossil fuel). Uniform technical design and technical standard of installation are followed. Retention time of slurry made the tank is around three months. Each biogas plant costs between US$ 251 to US$393.

The simplified baseline is the fuel consumption of the technologies that would have been used in the absence of project activity times an emission coefficient for the fossil fuel displaced.

The BSP meets project additionality requirement and as it is not a debundled component and it contributes to sustainable development.

Weighted average emission reductiom factor is 6.98 tCO2e/year/plant. Total estimated reduction from 9759 plants for 7 years crediting period (1Aug 2007 to 31 July 2014) is 327243 tCO2e (annual average 46749 tCO2e/year).

Constraints: i) Without CDM, the biogas sector in Nepal would diminish. Installation of at least 200000 biogas plants is necessary for economic viability. ii) It is extremely unlikely that the Terai household would realize at least 47% of fertilizer value from the bio-slurry, which is required for a profitable investment.

Environmental impacts of the project are related to health (pathogens in slurry, moisquito breeding, gas leakage), socio-economic and gender issues. A scientific EMP is possible to mitigate adverse impacts. A monitoring plan exists for EIA.

8.1.7 Preparation of Project Design Document of Micro Hydro Village Electrification CDM Project

The project aims at 2556 KW generation capacity in 25 districts of Nepal which are offgrid locations. Project will lead to reduction of GHG from burning of kerosene and natural wood. Hot water is planned to be produced to villagers using surplus electricity. The project will provide several positive socio-economic and environmental impacts (health, agro productivity, e-commerce, education etc.). It is estimated that the project activity will result in approximately 18771.26 tons of net emission reductions over a crediting life of 7 years (2009-2016).

8.2 RECOMMENDATIONS

Based on this study, following are the major recommendations:

- Biogas Support Programme and Microhydro Village Electrification Projects in Nepal will reduce 327243 tCO2e and 18771.26 tCO2e of carbon emissions and thus saving the fuelwood and kerosene.
- Carbon revenues to be earned from selling the generated CERs is necessary for the Biogas Support Programme to be commercially viable.
- Carbon revenues earned from selling the generated CERs helps in the sustainability of both Biogas Support Programme and Microhydro Village Electrification Project.
- Microhydro Village Electrification Project is implemented in the remote hilly areas where fuelwood is the main source of the energy. The fuelwood is collected from the nearby forest area in non-renewable way. The above project will help to minimize the dependency of project area people on forest for fuelwood and hence preserving the forest wealth which will serve as sink for Carbon.
- Biogas Support Programme and Microhydro Village Electrification Projects will help in reducing the import of LPG and kerosene and hence saving foreign currencies.
- Carbon trading is in Nepal's favor. In order to benefit from these opportunities, such as Biogas Support Programme and Microhydro Village Electrification Projects under CDM should be considered on priority basis.
- As certified ER credits are provided to the respective government, in absence of a strong commitment from the government sector, such benefits cannot be achieved. Therefore, CDM should be institutionalized and play an active role in promoting its energy projects in international carbon markets.
- Special focus is required on providing fiscal incentives such as subsidy for renewable energy technologies; tax exemption, low electricity tariff rate for clean transportation and industries so as to increase the consumption of electricity to replace imported fossil fuel.
- Projects based on indigenous resource and technology should be promoted. Therefore, hydropower should be given precedence.

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ANNEXURE- 1

BASELINE METHODOLOGIES FOR SMALL SCALE CDM PROJECTS WITH ILLUSTRATIVE EXAMPLES

I: BASELINE METHODOLOGIES FOR RENEWABLE ENERGY PROJECTS

IA: Electricity Generation by the User

This category comprises renewable energy units that supply individual households or users with a small amount of electricity. These technologies include solar power, hydropower, wind power, and other technologies that produce electricity all of which is used on-site by the user, such as solar home systems and wind battery chargers. The renewable power projects may be an entirely new generation capacity or a replacement of existing fossil fuel based generation plant. The capacity of these renewable energy generators should not exceed 15 MW.

Example-1: *A project to establish 10000 solar home systems (SHS) of 200 Wp capacity is an eligible CDM project. The total capacity of the project is 2 MW, which is below the 15 MW limit for the SSC projects.*

Energy Baseline

The simplified baseline is the fuel consumption of the actual technology in use, if the project is a replacement project. If the proposed project is entirely a new installation, the baseline is the amount of fuel that would have been used in the absence of the proposed project activity.

There are two options to estimate the energy baseline.

Option 1: based on the energy consumption of the consumers

Energy baseline is calculated as

$$\mathbf{EB = \sum i(n_i \cdot c_i)/(1 - l)}$$

where,

EB: annual energy baseline in kWh per year.

$\sum i$: the sum over the group of "i" renewable energy technologies implemented as part of the project.

n_i: number of consumers supplied by installations of the renewable energy technology belonging to the group of "i" renewable energy technologies during the year.

c_i: estimate of average annual individual consumption (in kWh per year) observed in the closest grid electricity systems among rural grid connected consumers belonging to the same group of "i" renewable energy technologies. If energy consumption is metered, ci is the average energy consumed by consumers belonging to the group of "i" renewable energy technologies.

l average technical distribution losses that would have been observed in diesel powered mini-grids installed by public programs or distribution companies in isolated areas, expressed as a fraction.

Option 2: Energy output

The energy baseline in this option is calculated as:

$$EB = \sum i \, O_i / (1 - l)$$

where,

EB annual energy baseline in kWh per year

$\sum i$ the sum over the group of "i" renewable energy technologies (e.g. solar home systems, solar pumps) implemented as part of the project.

O_i the estimated annual output of the renewable energy technologies of the group of "i" renewable energy technologies installed (in kWh per year)

l average technical distribution losses that would have been observed in diesel powered mini-grids installed by public programs or distribution companies in isolated areas, expressed as a fraction.

To continue with the above example-1, the energy baseline could be based on either data on electricity consumption of similar households in other villages that are connected to the grid or the baseline energy consumption could be estimated as the expected energy output of Solar Home System (SHS) installed under the project. In the example, SHS provides lighting needs of households. Therefore, the electricity consumption for lighting of similar households in a grid connected village could be used as the energy baseline.

Estimated annual electricity generation per SHS of 200 Wp in Example-1 = 0.146 MWh

Thus, total estimated electricity generated from 10,000 SHS = 10,000x0.146 = 1460 MWh

If the distribution loss was 10% of the electricity generated, then Energy baseline = 1460/(1-0.1 (average distribution loss in local grid)) = 1622 MWh

Emission baseline

The above options for estimating energy baseline give the energy consumption (kWh) or energy output supplied by the project activity. The energy baseline is converted into a GHG emissions baseline by multiplying the energy baseline by the CO2 emission coefficient for the fuel displaced (expressed in kg CO2/kWh) by the project activity.

Emission factor (kg CO2/kWh)

Project proponents can choose a default value 0.9 kg CO2e/kWh (derived from diesel generation units), or emissions factor from Table-1 (Table I.D.1 in Appendix B of the simplified modalities and procedures for small-scale CDM project activities). If the emissions factor chosen from Table-1 is greater than 0.9 kg CO2e/kWh, the project proponents will have to give a proper justification. The underlying baseline assumption is that in absence of the CDM project, the electricity needs of the user would have been met through a local grid supplied by diesel operated generator.

Continuing with example-1,

Emission baseline = Energy baseline x 0.9 kg CO2e/kWh = 1622x1000x0.9 kg CO_2e

= 1460 tCO_2e

Alternatively, project proponents could choose an emission factor value from Table-1, if 0.9 kg CO_2e/kWh is not appropriate for their case. Suppose in absence of the proposed CDM project a diesel generation based local grid would have been set up to meet the electricity of 10,000 households. Suppose the system were to operate for only 4-5 hours in the evening. The value of emission factor based on the above characteristic of the local grid from Table-1 is 1.3 kg CO_2e/kWh. Then the emission baseline will be:

= Energy baselinex1.3kg.CO_2e/kWh = 1622x1000x1.3 kg CO_2e = 2108 tCO_2/yr

I.B: Mechanical Energy for the User

This category comprises renewable energy generation units that supply individual households or users with a small amount of mechanical energy. These units include hydropower, wind power, and other technologies that provide mechanical energy, all of which is used on-site by the household or user, such as wind-powered pumps, solar water pumps, water mills and wind mills. Upgrading of an existing unit is not an eligible project under this category. Where generation capacity of the installation under the proposed CDM project is specified, it shall be less than or equal to 15 MW.

For example, if a solar water pump is the proposed CDM project to displace a diesel-based pumping system, the Wp capacity of solar panels will give the generation capacity. If the generation capacity is not specified, the estimated diesel-based electricity generating capacity that would be required to provide the same service or mechanical energy shall be less than 15 MW. In the case of irrigation where diesel fuelled pumps are used directly, the cumulative rating of diesel-fuelled pumps shall not exceed 15 MW. For example, if proposed CDM project replaces 1000 units of 5 hp diesel pumps then the cumulative rating of the replaced pumps is 5000 hp (or 3.73 MW), which would satisfy the 15 MW eligibility limit for the SSC project.

In cases where the unit added has both renewable and non-renewable components (e.g., a wind/diesel unit), the eligibility limit of 15 MW for a SSC project activity applies only to the renewable component. If the unit added co-fires [non-] renewable biomass and fossil fuel, the capacity of the entire unit shall not exceed the limit of 15MW.

Table-1: Emissions Factors for Diesel Generator Systems (in kg CO_2e/ kWh) for Three Different Levels of Load Factor

Cases	Mini–grid with 24 hour Service	Mini grid 4-6 hr/day Service Productive applications Water pumps	Mini-grid with storage
Load factors (%)	25%	50%	100%
<15kw	2.4	1.4	1.2
>=15<35kw	1.9	1.3	1.1
>=35<135kw	1.3	1.0	1.0
>=135<200kw	0.9	0.8	0.8
>200kw	0.8	0.8	0.8

Emission baseline

The simplified baseline is the estimated emission from consumption of diesel in a diesel generator that would serve same load as served by the project. The diesel emissions from a diesel generator displaced annually are calculated as:

(a) "Option 1" - If the output of the project is estimated in power units (kWh) Emission displaced = the power requirement (A) x hours of operation per year (B)x the emission factor for diesel generator systems (C) in Table-1

(b) "Option 2" - If the output of the project is estimated in terms of hours of operation of diesel generator.

Emission displaced = the diesel fuel consumption per hour (A)x hours of operation per year (B) x the default value for the emission coefficient for diesel fuel (3.2 kg CO2 per kg of diesel fuel, the IPCC default value).

Example-2: *A proposed CDM project will install wind water pumps for 100 farms of average size 2 hectares. The irrigation possibility will allow the farmers to grow two crops in a year with total water requirement of 12,800 cubic meter of water per farm in a year. In absence of the project the farmers would use a 5 hp diesel pump, which would have been operated for 280 hours in a year to meet the water requirement. Average diesel consumption of the diesel pump is 1.125 liters per hour (or 0.933 kg/hour).*

Considering the first criterion, the wind units installed will supply mechanical energy to farmers on site; therefore, the project is eligible under this category. To estimate the size of project, in absence of MW rating of wind pumps, the size of alternative to meet the irrigation demand of 100 farms can be used to check eligibility as follows:

No. of farmers covered under the project (A)	= 100
Total number of hours of operation (B)	= 280 hours
Approximate size of motor to provide the discharge (C)	= 5 hp
Total capacity of diesel based generation set to meet the power requirement (D=AxCx(0.746 kW/hp))	= 5x100x0.746
	= 373 kW

Total capacity required is 373 kW, which is less than 15 MW, hence, the project qualifies as SSC.

Use "Option 1" to estimate the emission baseline, where the emission factor for a diesel-based generation system with more than 200 kW capacity is 0.8 kg CO_2/kWh (Table-1).

Therefore, the emission baseline = 373 kWx280 hoursx0.8 kg CO_2/kWh = 83.55 tCO_2

Alternatively one could use "Option 2" as follows:

Emission Baseline = (100x0.933 kg/hour)x280 hoursx3.2 kgCO_2/kg = 83.55 tCO_2

I.C: Thermal Energy for the User

This category comprises renewable energy units that supply individual households or users with thermal energy that displaces fossil fuel or non-renewable sources of biomass. Upgrading of existing units is not an eligible CDM project under this category. Examples include solar thermal water heaters and dryers, solar cookers, energy derived from biomass for water heating, space heating, or drying, and other technologies that provide thermal energy to displace the use of fossil fuel. An example of such project is biogas projects that produce biogas for use in cooking and thereby replacing use of unsustainable wood.

Biomass-based co-generating systems that produce heat and electricity for use on-site are included in this category. Where generation capacity is specified by the manufacturer, it shall be less than 15 MW. For co-generation and/or co-fired systems to qualify under this category, the energy output should not exceed 45 MW thermal. Thus for a biomass based co-generating system the rating for all the boilers combined should not exceed 45 MW thermal.

The project proponents can choose one out of the following three cases for estimating the emissions baseline depending on the nature of service provided by the project.

Case 1: The project displaces fossil fuel technologies. The baseline estimation is based on the fuel consumption of the technologies that would have been used in the absence of the proposed CDM project activity.

Energy baseline = Total fuel required to provide the same level of service as project (A)

Emission Baseline = Ax emission coefficient (kg CO2/unit) of the fossil fuel used (B).

IPCC default values for emission coefficients may be used for estimating the emission baseline. For example, a CDM project uses solar thermal dryer in place of diesel based dryer. The energy baseline is the amount of diesel that is consumed in the diesel based dryer. The emission baseline is then estimated by using the emission factor for diesel.

Case 2: The project displaces non-renewable sources of biomass

Energy baseline = consumption of the non-renewable sources of biomass (kg) of the technologies that would have used in the absence of project (A).

Emission baseline = A x Carbon content of biomass (B)

For example, consider the case of a solar cooker used for cooking in place of a biomass cook stove. The consumption of biomass used to meet the cooking energy requirement is the amount of biomass displaced by the project. The emissions baseline is the emission from the non-renewable fraction of displaced biomass. IPCC default values for emission coefficients may be used. Continuing with the example, say the heat content of a meal cooked by a solar cooker is X MJ. The efficiency of the biomass stove, expressed in percentage, used in absence of a solar cooker is e. The percentage of non-renewable biomass used for cooking is f. The emission baseline in this case can be calculated as follows:

Heat content of meal cooked by Solar cookers (A)	= X MJ
Efficiency of biomass cookstove (B)	= e
Biomass energy required to meet X MJ energy (C = A/B)	= X/e = Y MJ
Fraction of unsustainable biomass in biomass saved by use of Solar cooker (D)	= f
Emission Baseline (E = (DxCx carbon content of biomass expressed in CO_2)	=fxYx(carbon content of biomass tCO_2/MJ)

<u>Case 3: The project displaces electricity in the baseline</u>

Energy baseline = The electricity consumption (A)

Emission baseline = Ax the relevant emission factor calculated as described in category I.D (Grid connected renewable electricity).

For example, consider the case of a solar water heater used in place of an existing electric water heater. The electricity in the village is provided through a local grid powered by a diesel generator. Suppose the diesel generator supplies households 5 hours a day; the total load is 120 kW; and, the load factor in the system is approximately 50%. Suppose the amount of electricity saved annually by use of the solar water heater in the village is 100 MWh.

Energy baseline = 100 MWh = 100,000 kWh

From Table-1 the emission factor in this case is 1 kg CO2/kWh, based on the characteristics of the diesel generator based local grid.

Emission baseline = 100,000 kWhx1 kg CO_2/kWh = 100,000 kg CO_2 = 100 tCO_2

I.D: Renewable Electricity Generation for a Grid

This category comprises renewable energy generation units, such as photovoltaic, hydro, tidal/wave, wind, geothermal, and biomass, that supply electricity to an electricity distribution system (grid) that is or would have been supplied by at least one fossil fuel or non-renewable biomass fired generating unit.

If the unit added has both renewable and non-renewable components (e.g. a wind/ diesel unit), the eligibility limit of 15 MW for a small-scale CDM project activity applies only to the renewable component. If the unit added co-fires [non-] renewable biomass and fossil fuel, the capacity of the entire unit shall not exceed the limit of 15MW. Biomass based combined heat and power (co-generation) systems that supply electricity to a grid are included in this category. To qualify under this category, the total energy output of the combined system should not exceed 45 MW thermal.

This category includes projects based on use of recovered methane for electricity generation from land fill gas, waste gas, wastewater treatment and agro-industries treatment. These projects involve biogenic sources of methane emission and, therefore, CO2 emissions resulting from burning of CH4 in these projects are not considered as emissions. This is because the organic matter, which results in release of methane, absorbed carbon from the atmosphere. Therefore, the carbon released on burning of methane was in the first place absorbed from the atmosphere and, hence, net emissions of the total cycle are zero. If the source of methane is nonorganic, coal bed methane, then the above is not true and, therefore, such projects cannot be included in this project category. Two cases of estimating the baseline in this category follow.

Case 1: System where all electricity generation units use exclusively fuel oil or diesel fuel

The baseline for such a system is the annual kWh generated by the project multiplied by an emission coefficient (measured in kg CO2e/kWh). The emission coefficient can be chosen from Table-1. The appropriate choice of emission coefficient is based on the relevant capacity of the system (in kW) and the load as well as the system characteristic as indicated in column heads of Table-1.

Case 2: Systems other than those covered by Case 1

The energy baseline is estimated by the product of kWh produced by the project and appropriate emission coefficient (measured in kg CO_2e/kWh). The emission coefficient for the system is calculated using one of the following methods: Method A: The average of the "approximate operating margin" and the "build margin", where:

a) The "approximate operating margin" is the weighted average emissions (in kg CO_2e/kWh) of all generating sources supplying electricity to the system. The generation units based on hydro, geothermal, wind, low-cost biomass, nuclear and solar generation are excluded while estimating the emission coefficient. The emission coefficient is calculated as the sum of total emission from each of fossil fuel based generation units, other than those mentioned above, divided by the sum of the generation from each of the fossil fuel based generation units in that year. The total emissions from each generating unit are estimated as total fossil fuel consumed by the unit multiplied by the carbon intensity of the fuel.

b) The "build margin" is the weighted average emissions (in kg CO_2e/kWh) of recent capacity additions to the system. The recently added generation units are identified using two methods. First, identify the five most recent installations in the system by ordering all the generation units in descending order of date of commissioning. If the total generation (MWh) of recent 5 additions is less than 20% of the total system generation, then include generation units starting from sixth unit in the list till the total generation by the generating units included is at least 20% of total system generation.

Alternatively, calculation of the emission coefficient for the system could use the following method.

Method B: The emission factor is the weighted average emissions (in kg CO_2e/kWh) of all the generation units in the system. The emission coefficient is calculated as sum of total emission from each of the generation units divided by the sum of their generation in that year. The total emission from each generation unit is estimated as total fuel consumed by the generating unit multiplied by the carbon intensity of the fuel.

The project participants should provide complete information on data used for estimation. Also, the project participants should try to use the data values for different parameters in such a way that the emission baseline is conservative; that is, results in a lower estimate.

Example-3*: Suppose a proposed CDM project is a run-of-the-river grid connected hydropower project with the rated capacity of 5 MW. Expected power generation from the project is 22,000 MWh/year.*

As the rated capacity of project in example-3 is less than 15 MW and is based on renewable energy, the project falls under type 1 "Renewable Energy Projects". Further, as the project generates electricity for supply to the grid, it falls in category 1.D. The project is situated in a country where diesel and fuel oil based generation system supply 70% of electricity and the remaining is supplied by hydro sources. In the last 5 years, all the new capacity added is based on diesel and fuel oil. It is also expected that future additions to power generation capacity will be based on fuel oil or diesel though some exploitable hydro capacity is available.

Since, all the fossil fuel generating units are diesel and fuel oil based, the project is under Case 1 of the project category, i.e., the baseline emission factor is the emission factor of the diesel based generation system of appropriate capacity and load factor. Table-1 can be used to choose the appropriate emission factor. In example-3, since the system capacity is greater than 200kW, the emission factor of 0.8 would be applicable.

Annual baseline emission (tCO_2)

= annual generation by proposed project x emission factor

= 22,000 MWh x0.8 (tCO_2/MWh) = 17,600 tCO_2

If, the fossil fuel plants in the grid are based on fuel other than fuel oil or diesel than the baseline emission factor is estimated the method described for Case 2. The baseline emission factor is based on all the generation units based in the system, therefore, the first step is to identify the system boundary. The guideline on the baseline methodology does not define the system boundary. The system boundary should be defined by the grid system where the exports and imports form a negligible fraction of total generation within the system. The simpler of the two methods for estimating emission factor in Case 2 is the average emission of all existing generation sources in the system (Table-2).

Table-2: Estimation of Emission Factor for Example-3

Fuel	Net Generation (GWh)	Net Consumed (103 tonnes) (A)	Fuel Calorific Value (TJ/103 tonnes) (B)	Carbon Emission Factor (IPCC; tc/TJ) (C)	Emission tCO2 (D)= (A)x(B)x(C)
coal	72563	50776	16.22	25.8	77911301
Lignite	16368	11454	16.22	27.6	18801328
Gas	18826	3743	43.33	15.3	9098533
Hydro	16587			0	0
Nuclear	4122			0	0
Total	128466				105811162
Baseline emission factor (tCO_2/GWh)					823.65

In absence of fuel data, net heat rate data can be used to estimate the CO_2 emission for fuel source, which can be expressed as produce of net generation, net heat rate, and carbon emission factor.

One tonne of carbon (tC) is equal to 44/12 tonne of CO_2 (tCO_2)

The baseline emission in this case is 22x823.65 = 18,121 tCO_2

II: BASELINE METHODOLOGIES FOR ENERGY EFFICIENCY IMPROVEMENT PROJECTS

II.A: Supply Side Energy Efficiency Improvements Projects – Transmission and Distribution Projects

This category comprises technologies or measures to improve the energy efficiency of the transmission and distribution system for electricity supply or district heating up to the equivalent of 15 GWh per year (or 54 TJ per year). Examples include upgrading the voltage of a transmission line, replacing a transformer, and increased insulation of the pipes in a district heating system. The technologies or measures may be applied to existing transmission or distribution systems or be part of an expansion of a transmission or distribution system.

Energy Baseline

In retrofit projects, energy efficiency equipment is installed in an existing facility to replace old equipments. The energy baseline is the technical losses of energy within the project boundary. The project boundary is defined as a physical, geographical boundary of the portion of the transmission and/or distribution system where the energy efficiency measures are implemented. The technical loss of energy in transmission and distribution is calculated as either (1) the measured performance of the existing equipments, or (2) the performance of the existing equipments as determined using a standard selected in accordance with the following:

(i) The national standard for the performance of the equipment type,

(ii) In absence of national standard values, an international standard for the performance of the equipment type, such as International Organization for Standardization (ISO) and International Electro technical Commission (IEC) standards.

(iii) If international standard values are not available, the manufacturer's specifications provided that these are tested and certified by national or international certifiers.

For projects, where energy efficiency equipment is installed in a new facility, the energy baseline is the technical losses of the equipment that is most likely to be installed. For example, if the existing heat distribution system is being expanded, the pipes used are expected to have better insulation than the pipes in the existing network even without CDM. Therefore, the baseline is insulation efficiency of most commonly used better pipes than the previously used pipes in the distribution network. See the example-4.

Example-4: *Suppose a proposed CDM project will renovate an existing heat distribution system. Suppose the existing losses in the distribution system, as per the measurements carried out, are 10% and it is estimated that the renovation of the distribution system will reduce the loss to 7%. Assume that the present amount of heat distributed through the system is 100 Giga joules (GJ).*

The energy baseline in case of example-4 can be estimated as follows:

Measured loss in distribution system (A) = 10%

Estimated distribution loss in system after renovation (B) = 7%

Total amount of energy used to meet the heat demand in the baseline (C) = 100GJ

Energy baseline = energy loss in the distribution system in absence of project (D = (A/100)x(C) = 0.1 x100 = 10 GJ# = 0.1 TJ

#: Project is eligible under SSC as its reduction per year (0. TJ) is less then 54 TJ.

Emissions baseline

The emission baseline is the energy baseline multiplied by an emission coefficient for the type of energy saved. If the energy saved is electricity, say, due to energy efficient equipment to reduce technical losses in the electricity distribution system, the emission coefficient (in kg CO_2e/kWh) is calculated in the same manner as that for the project category I.D.

If energy saved is heat, say, due to measures implemented to improve the efficiency of a district heating system, the emission coefficient (in kg CO2e/ unit of energy) is that of the fossil fuel used by the system. IPCC default values for emission coefficients can be used.

Continuing with example-4, say the fuel used for generating heat is coal. The emission baseline for the project can be estimated as follows:

Carbon content of Coal (E) = 25.8 tC/TJ*

Baseline emission = Energy BaselinexEmission factor (F) = (ExD) = 25.8 tC/TJx 0.1TJ = 2.58 tC

II.B: Supply Side Energy Efficiency Improvements – Generation

This category comprises technologies or measures to improve the efficiency of fossil fuel generating units that supply either an electricity or thermal system by reducing energy or fuel consumption up to the equivalent of 15 GWh per year. Examples include efficiency improvements at power stations and district heating plants and co-generation (excluding biomass cogeneration projects, which are covered under category I.C or I.D). The project could be either an upgrading of existing units by efficient technologies or measures or a part of a new facility.

Efficiency improvements in non-fossil fuel generating units, such as turbine replacement for hydro projects, shall be treated as incremental generation using renewable energy. The incremental generation is calculated using measured efficiency improvement, expressed as a percentage, and the measured output of the unit. The emission baseline in this case is incremental generation multiplied by the emission factor calculated in accordance with category I.D projects. This is illustrated through example-5.

***Example-5**: In case of a proposed CDM project to improve the efficiency of a small hydro project, the improvement in efficiency is 3%. The existing annual generation of the unit is 10 GWh with an efficiency of 40%, therefore, the annual energy input is 25 GWh. A 3% energy efficiency improvement results in increase in generation by 3% of 25 GWh or 0.75 GWh. To estimate the baseline emission this increase in production is treated as new generation from a renewable unit. The emission factor for this incremental generation is estimated as per the calculations for category I.D projects.*

Energy baseline

The energy baseline is the technical losses of energy in generating unit within the project boundary. The project boundary is defined as the physical/geographical site of fossil fuel generating unit affected by the efficiency measure. In the case of retrofit projects, the energy baseline is calculated as the monitored performance of the existing generating unit. For example, efficiency of a generation unit through installation of improved boiler, the energy baseline is energy losses of the existing boiler as per the measurement of performance of the boiler.

If the project involves installation of energy efficiency equipment (e.g., boilers in a power generation unit) in new facilities, the energy baseline is calculated using a standard efficiency for the equipment (the boiler in this example) that would have been installed in the absence of the project.

Emission baseline

The emission baseline is expressed as

Emission baseline = the energy baseline (A) x emission coefficient (kg CO2/unit of energy) for the fuel used by the generating unit.

IPCC default values for emission coefficients may be used.

II.C: Demand Side Energy Efficiency Programmes for Specific Technologies

This category comprises programs that encourage the adoption of energy-efficient equipment (lamps, ballasts, refrigerators, motors, fans, air conditioners, appliances, etc.) at many sites. The project could involve either a replacement of existing equipment or installation at new sites. The aggregate energy savings by a single project may not exceed the equivalent of 15 GWh per year.

The projects in this category could result in savings either in fuel consumption or in electricity consumption.

Energy baseline (fuel consumption)

If the project results in saving of fossil fuel, the energy baseline for a retrofit project is the existing fuel consumption of the installation or equipment. In the case of a new facility, the energy baseline would be the amount of fuel that would be used by the technology that would be implemented in absence of the proposed project.

Emissions baseline

The emission baseline is derived as the energy baseline multiplied by an emission coefficient (kg CO_2/ unit of energy) for the fossil fuel displaced. IPCC default values may be used for emission coefficients. Emission baseline for example-6 is presented in Table-3.

Example-6: *Suppose conventional (less efficient) diesel pump sets used in small industrial units are replaced by efficient and appropriately sized diesel pump sets. The project involves replacement of N1 number of 5 hp conventional pump sets and N2 number of 7 hp conventional pump sets in region 1, and N3 number of 5 hp in region 2. The total amount of diesel consumed by all the conventional pump sets to be replaced by the program is the energy baseline. The total amount of diesel consumed can be estimated as in Table-3.*

Table-3: Estimation of Diesel Consumption for Example-6

Group	Number of pumpsets	Fuel used per hour by conventional pumpset (kg/hr)	Number of hours of use per year	Total Diesel Consumption (kg)	Total CO_2 emission in kg (Diesel consumption x3.2#)
5 hp in region 1	N1	D1	H1	N1xD1xH1 = EB1	N1xD1xH1x3.2 = B1
7 hp in region 1	N2	D2	H2	N2xD2xH2 = EB2	N2xD2xH2x3.2 = B2
5 hp in region 2	N3	D3	H3	N3xD3xH3 = EB3	N3xD3xH3x3.2 = B3
Total				Energy Baseline = EB1+EB2+EB3	Emission Baseline = B1+B2+B3

#: IPCC default value of emission coefficient for diesel is 3.2 kgCO2/kg of diesel.

Energy baseline (electricity consumption)

If the energy displaced by the project is electricity, the energy baseline is calculated as follows:

EB = ∑ i(ni . pi . oi)/(1 - l)

where

EB: annual energy baseline in kWh

∑i: the sum over all types of devices replaced (e.g. 40 W incandescent bulb, standard electric motor, etc.) under the project.

Ni: the number of units replaced of type "i" devices.

Pi: the power rating of the devices of type "i" (e.g. 40 W incandescent lamp, standard electric motor). In the case of a retrofit programme, "power rating" is the weighted average* of the devices replaced. In the case of new installations, "power rating" is the weighted average of devices on the market. For example, if incandescent lamps are used presently and the project replaces them with compact fluorescent lamps (CFLs), the power rating of the incandescent lamp is used. But if a new facility is being constructed where CFLs will be fitted for lighting, the baseline will be fluorescent tube lights rather than incandescent lamps, as fluorescent tube lights are the only available alternative devices in the market.

oi the average annual operating hours of the devices replaced of type "i".

l average technical distribution losses for the grid serving the locations where the devices are installed, expressed as a fraction.

** Weights are the relative proportion of each sub-type of device. For example, if lamps are being replaced then the power rating is for weighted average of incandescent lamps and fluorescent tube lights, where the weights are the proportion of each lamp type in total lamps replaced.*

Emissions baseline

The emission baseline is obtained as a product of the energy baseline and an emission coefficient (measured in kg CO_2e/kWh) for the electricity displaced calculated in accordance with provisions of Category I.D projects. Table-4 explains the estimation of emission baseline for example-7.

Example-7: *Suppose a proposed SSC project uses CFLs, efficient motors and efficient fans in a new facility where energy efficiency equipments are used as CDM project. The power rating of devices that would have been used in absence of CFLs, efficient motors and efficient fans are PC, PM and PF respectively. The energy displaced by project is electricity. The energy baseline and emission baseline for the project can be estimated as in this Table-4.*

Table-4: Energy Baseline and Emission Baseline Estimation for Example-7

Equipment type	Number	Power rating of replaced equipment (kW)	Annual operating hours	Total baseline Power consumption (kWh)
CFLs	C	Pc	Hc	CxPcxHc = PCC
Efficient motor	M	Pm	HM	MxPmxHm = PCm
Efficient fans	F	Pf	Hf	FxPfxHf = PCf
Total power that would have been consumed by the replaced equipments (A)				= PC = PCc +PCm +PCf
Transmission and distribution loss in the grid system (only technical losses) (B)				= 0.1 (=10%)
Total power generation required to meet the power requirement of replaced equipments (C) = (A)/(1-(B))				= PC/(1-0.1)
Emission coefficient of electricity as estimated in example-3 shown in section I.D				= 0.842 kg CO_2/kWh
Emission baseline (E)				= (C)x(D) = PC/(1-0.1)x0.842

II.D: Energy Efficiency and Fuel Switching Measures for Industrial Facilities

This category comprises an energy efficiency and fuel switching measure implemented at a single industrial facility. For example, energy efficiency measures (such as efficient motors), fuel switching measures (such as switching from steam or compressed air to electricity) and efficiency measures for specific industrial processes (such as steel furnaces, paper drying, tobacco curing, etc.). A project under this category could be either replacement of existing equipment or installation of a new facility. The aggregate energy savings of a single project should not exceed the equivalent of 15 GWh per year.

A project activity that primarily involves fuel switching falls under category III.B.

Energy baseline

The energy baseline in the case of retrofit measures represents the energy use of the existing equipment that is replaced. In case of a new facility the energy baseline is the energy use of the facility that would otherwise be built in absence of the proposed project.

Emission baseline

Each type of energy in the energy baseline is multiplied by an appropriate emission coefficient (in kg CO_2e/kWh). For the electricity displaced, the emission coefficient is calculated in the same manner as for project under category I.D projects. For fossil fuels displaced, the IPCC default values for emission coefficients may be used.

Example-8: *Suppose an advanced fuel firing and control system for a reheat furnace based on fuel oil in a steel re-rolling unit is implemented under the proposed SSC project. The annual output of the furnace is 60,000 tonnes of heated ingot. The installation of a system on the furnace does not change the output of the furnace but reduces the energy consumption by optimal control of fuel injection and air supply. The fuel consumption per tonne of ingot heated is 80 kg. The estimated energy consumption per tonne of ingot heated after implementation of the proposed SSC project is 70 kg.*

The emission baseline for the example-8 can be estimated as follows:

Energy Baseline (A)	=	80x60,000x 40.33 TJ/ '000 tonne (IPCC default for Fuel oil) = 193.6 TJ
Emission factor (B)	=	21.1 tC/TJ*
Baseline emission	=	Energy Baseline xemission factor (C = (AxB))

= 21.1 tC/TJx 193.6 TJ = 4084.6 tC

Energy consumed under project = 70x60,000x 40.33 TJ/ '000 tonne = 169.4 TJ

Project eligibility under SSC = 193.6 TJ – 169.4 TJ = 24.2 TJ ≤ 54 TJ

II.E: Energy Efficiency and Fuel Switching Measures for Buildings

This category comprises energy efficiency and fuel switching measures implemented either at a single building, such as a commercial, institutional or residential building, or at a group of similar buildings, such as a school or university. A project using CFLs to replace incandescent lamps and/or fluorescent tube lights in residential accommodations in a town will fall under this category, but a similar project focused on a group of residential buildings, factory premises, and a commercial building all together will fall under II.C.

Category II.E covers project activities aimed primarily at energy efficiency. A project activity that primarily involves fuel switching falls into Category III.B. Examples of projects in this category include technical energy efficiency measures (such as efficient appliances, better insulation and optimal arrangement of equipment) and fuel switching measures (such as switching from oil to gas). The project could be either replacement of existing equipment or installation of new facilities. The aggregate energy savings of a single project should not exceed the equivalent of 15 GWh per year.

Energy baseline

The energy baseline represents the level of energy use by the existing equipment that is replaced in the case of retrofit measures. In the case of a new facility the energy baseline is the energy use by the facility that would otherwise be built.

Emission baseline

To derive the emission baseline, the amount of energy displaced of each type is multiplied by a corresponding emission coefficient. In the case of electricity displaced, the emission coefficient is calculated in accordance with provisions for Category I.D projects. For fossil fuels, the IPCC default values for emission coefficients may be used. Table-5 presents the estimation of emission baseline for example-9.

Example-9: *Suppose replacement of incandescent bulbs and fluorescent tube lamps by CFLs in residential buildings in a City will be eligible project under Category II.E.* Let us assume that CFLs replace use of 4000 incandescent bulbs and 6000 fluorescent tube lights. The transmission and distribution (T&D) losses in the grid in which the project area lies is 10%. Assume that power rating of incandescent bulbs is 0.065 kW and that fluorescent tube lights is 0.036 kW and the annual operating hours per device for both is 2920. Since the energy displaced is electricity, the emission factor as per Category I.D for example-3 is used, which is 0.842 tCO_2/MWh.

Table-5: Estimation of Emission Baseline for Example 9

Equipment type	Number (A)	Power rating of replaced equipment (kW) (B)	Annual operating hours (C)	Total Power consumed (MWh) (D = AxBxC/1000)
CFLs	4000	0.065 (incandescent bulb)	2920	759.2
CFLs	6000	0.036 (tube light)	2920	630.72
Total power that would have been consumed by the replaced equipments, MWh (E)				= 1389.92 (= 759.2+630.72)
T&D loss (only technical losses)#(F)				= 0.1 (=10%)
Energy baseline, MWh (G = E/(1-F))				=1389.92/(1-0.1) =1544.35
Emission factor of displaced electricity (H)				=0.842tCO_2/MWh
Emission baseline (tCO_2) (I = GxH)				= 1544.35x0.842 = 1300

#: As the electricity is supplied from the grid, the grid technical losses can be used to estimated total electricity saved.

II.F: Energy Efficiency and Fuel Switching Measures for Agricultural Facilities and Activities

Projects that implement energy efficiency and/or fuel switching measures in agricultural activities or facilities or processes are covered under this category.

Examples of energy-efficient practices include efficiency measures for specific agricultural processes (such as decrease in irrigation used, etc.), and measures leading to a reduced requirement of farm power per unit area of land, reflected in lesser number of hours of tractor use or smaller capacity tractors, and less use of farm equipments. Further energy efficient measures would be reducing fuel use in agriculture, such as reduced machinery use through, e.g. the elimination of tillage operations, reduction of irrigation, use of lighter machinery, etc. Examples of fuel switching measures include switching from diesel to ethanol or biodiesel.

The projects could be either a replacement of existing equipment or installation of equipment in a new facility. The aggregate energy savings of a single project may not exceed the equivalent of 15 GWh per year.

Energy baseline

(a) Energy baseline in the case of retrofit measures would be expressed in terms of energy consumption of the existing activity that would be avoided;

or

(b) In the case of a new facility the baseline would be expressed as energy consumption of the facility that would otherwise be installed.

If the project results in fossil fuel saving (reduced tillage activity implies lower tractor use and, hence, lower fossil fuel use) the energy baseline is the fossil fuel consumption of the baseline activity. The fuel consumption can be expressed as total fuel consumption for baseline activity or as a product of fuel consumption per unit area and total area under agricultural activity.

If the project results in savings in electricity (say, reduced water requirement implies lower use of electric pumps to irrigate and, hence, savings in electricity), the energy baseline is consumption of electricity by baseline activity divided by technical transmission and distribution losses for the electrical grid serving the agricultural facility.

The demonstration of additionality for projects under this category is necessary, especially with respect to some financial indicators. Also the project participants should clearly demonstrate that reduced energy consumption is not due to decrease in the activity (say, decrease in cropped area) due to financial constraints faced by them, but is due to the CDM-driven activity.

Example-10: *A proposed CDM project involves adoption of a no-tillage method of farming on 1000 hectares of agricultural land. Assume that annual operating hours of a tractor for tilling a hectare of land is 500 and a tractor consumes on average 10 kg of diesel per hour. Therefore, the total amount of diesel saved by adopting no-tillage method is 5,000 tonnes.*

Energy and emission baseline for example-10 can be estimated as follows:

Energy baseline (A) = 5000 tonnes diesel

Emission factor for Diesel (B) = 3.2 tCO2 /tonne diesel (IPCC default value)

Emission baseline (C =(A)x(B) = 5000 tonnesx3.2 tCO2 /tonne diesel = 16,000 tCO2

III: BASELINE METHODOLOGIES FOR OTHER EMISSION REDUCTION PROJECTS

III.A: Agriculture

The CDM-EB is still to finalize the simplified baseline methodology for this category of projects.

III.B: Switching Fossils Fuels

This category comprises fossil fuel switching in existing industrial, residential, commercial, and institutional or electricity generation applications. The fuel switching activity of the proposed project may change efficiency of the system as well. The primary focus of the project activity should be to reduce emissions through fuel switching. If fuel switching is a part of the project activity focused primarily on energy efficiency, the project activity falls in Category II.D or II.E.

Emission baseline

The emission baseline is the current emissions of the facility expressed as emissions per unit of output (e.g., kg CO_2e/kWh). IPCC default values for emission coefficients may be used.

Example-11: Say, a proposed CDM project switches from fuel oil use to gas in reheating furnace in a steel re-rolling mill. Assume that existing annual fuel consumption of the steel mill is 6441.6 kiloliters (product of annual production (105,600 tonnes) and fuel intensity of production (61 liters fuel oil per tonne of output)). Say, the energy required per tonne of steel in gas furnace is 1866 MJ.

The emission baseline for example-11 can be estimated as follows:

Annual output of the mill (A)	= 105,600 tonnes
Annual Fuel oil consumption (B)	= 6441.6 kilo liters (5340 tonne)
Emission factor of Fuel Oil (tC/103 tonne) (C)	=848 (IPCC default for residual fuel oil)
Annual CO2 emissions (tonne) (D = BxCx44/12)	= 0.848x5340x44/12 = 16604

Emission baseline (E = D/A)	= 16604/105600 = 157 kgCO_2/tonne output

For the proposed CDM project to be eligible under SSC, total project emissions should be less than 15 kilotonne CO_2. Since the estimated emission from project is less than 15 kilotonne CO_2, as shown in calculations below, the project is eligible under SSC.

Annual output of the mill (A)	= 105,600 tonne
Estimated Energy required per tonne of steel heated (B)	= 1866 MJ/tonne
Estimated annual energy required (C = AxB)	= 197.050 TJ
Emission factor of Gas (tC/TJ) (D)	= 15.3 (IPCC default for residual fuel oil)
Estimated project CO_2 emissions (tonne) (E = DxCx44/12)	= 15.3x197.05x44/12 = 11056

III.C: Emission Reductions by Low-Greenhouse Gas Emitting Vehicles

Projects aiming at reducing GHG emission through low-GHG emitting vehicles are included in this category. A project activity in this category should both reduce anthropogenic emissions by sources and directly emit less than 15 kilotonnes of carbon dioxide equivalent annually.

Emission baseline

The emission baseline is measured as product of the energy use per unit of service for the baseline vehicle (A), the average annual units of service per vehicle (B), the number of vehicles affected (C), and the emission coefficient for the fuel used by vehicle (D) that would have been used in absence of the project. Therefore, the emission baseline can be expressed as,

Emission baseline = AxBxCxD

If electricity is used by the vehicles, the associated emissions shall be estimated in accordance with methodology category I.D project activities.

Example-12: *Say, a proposed CDM project involves use of ethanol to substitute 10% gasoline in a fleet of 1000 private cars. Assume that on average cars consume 0.1 litre of gasoline per km and the average annual travel is 10,000 km. Substitution of* *gasoline by ethanol does not result in any change in fuel use efficiency; therefore, the reduction in gasoline is equal to the amount of ethanol used in the cars.*

The baseline for example-12 can be estimated as shown below.

Fuel consumption of a car per km (A)	= 0.1 litre gasoline (0.074 kg)
Average annual distance traveled per car (B)	= 10,000 km
Number of cars covered in the project (C)	= 1000
Emission factor of gasoline(kgC/ tonne) (D)	= 847 (IPCC default for gasoline)
Emission baseline (tonne CO2) (E = AxBxCxDx44/12)	= (0.074x10,000x1000x0.847)x 44/12 = 2298.2
Project emission (tonne CO2)	= 0.9x2298.2 = 2068.4*

**: In project case 0% of gasoline consumption is replaced by ethanol, which is produced from organic sources and has zero GHG emissions. Therefore, only 90% of baseline gasoline used in baseline results in emissions during project case.*

The calculations above show that project emissions are 2.07 kilotonne of CO2, which is less than the 15 kilotonnes value, hence, the project is an SSC project.

III.D: Methane Recovery

This category includes projects that prevent release of methane emissions into the atmosphere from coal mines, agro-industries, landfills, wastewater treatment facilities and other sources through measures to recover the emitted methane. This category includes projects that process organic components of municipal solid waste prior to its disposal in a landfill site and reduces the potential for methane emissions. But projects that use the organic component of municipal solid waste for incineration to avoid methane emissions are not covered in this category. If the methane captured is from a non-biogenic source (methane captured in coal mines) then the CO2 emission from the combustion of captured methane is counted in project emissions.

Emission baseline

The emission baseline is defined as the amount of methane that would be emitted to the atmosphere in the absence of the proposed project activity. In the case where certain proportion of methane in the baseline is captured and flared, then it is also accounted for.

It should be noted that in the case of landfill gas, waste gas, waste water treatment and agro-industries projects, if recovered methane is used for electricity generation, the proposed project activity is also eligible under Category I.D. If in a project, methane recovered is used for heat generation, the project is also eligible under Category I.C. In such cases, project participants may submit one single project design document for all of the components of the proposed project activity.

Example-13: *Suppose a proposed CDM project will install a gas recovery system in an existing landfill site, which daily receives 20,000 tonnes of waste (W). The captured gas will be used to generate electricity and supplied to the grid. The project will also install a flaring system to flare gas captured in excess of that used for generating electricity.*

The gas capture component of the proposed project falls under category III.D, whereas, the use of gas to produce electricity component will fall under category 1.D. Project proponents can develop one single PDD for both these components.

The baseline (BE) for the project in example-13 is calculated using the IPCC recommended methane estimation method, as below:

BE	= W x MFx 2114, and
MF	= MCF x DOC x DOCF x F x 16/12
Methane Correction Factor (MCF)	= 0.6 (IPCC Default)
DOC	= 0.18 (IPCC Default)
DOCF= Fraction DOC dissimilated as landfill gas	= 0.77 (IPCC Default)
F = fraction of CH4 in landfill gas	= 0.5 (IPCC Default)
Methane factor for waste (MF)	= (0.6x0.18x0.77x0.5) = 0.042
Baseline emission, BE	= 20,000x0.042x21 = 17,640 tonnes

Assume that in example-13, 10% of methane generated during project phase will escape into atmosphere, that is, only 90% of the methane generated during project phase is captured.

Project emissions = 0.1x17,640 = 1764 tCO2e, since this is less than 15 kilotonne, the project is eligible as an SSC project. Also note that CO2 emission from flaring or burning the CH_4 in generator is not accounted for because the source of gas is organic.

III.E: Avoidance of Methane Production from Biomass Decay through Controlled Combustion Technology/Measures

This category includes project activities that avoid the production of methane from biomass or other organic matter, which otherwise would have been left to decay and emit methane. The methane emission is avoided by utilization of the biomass or organic matter for controlled combustion in the project scenario. The project activity here does not recover or combust methane (unlike Category III. D). For example, a project that uses the organic component of municipal solid waste for incineration to avoid methane emissions will be covered in this category.

Emission baseline

The baseline scenario is the situation where the biomass and other organic matter would be left to decay within the project boundary resulting in generation of methane which would be emitted to the atmosphere. The baseline emission is the amount of methane generated from the decay of the biomass or organic waste that would be treated in the project activity. IPCC default emissions factors can be used. The baseline (BEy) can be estimated using as follows:

BEy = Qbiomass x CH4_IPCCdecay x GWP_CH4

where,

Qbiomass	Quantity of biomass treated under the project activity (tonnes)
CH4_IPCCdecay	IPCC CH4 emission factor for decaying biomass in the region of the project activity (tonnes of CH4/tonne of biomass or organic waste)
GWP_CH4	GWP for CH4 (tonnes of CO2 equivalent/tonne of CH4)
CH4_IPCCdecay	= (MCF x DOC x DOCF x F x 16/12) where,
MCF	methane correction factor expressed as fraction (default value of parameter as per IPCC is 0.4)
DOC	degradable organic carbon expressed as fraction (IPCC default is 0.3)

DOCF	fraction DOC dissimilated to landfill gas (IPCC default is 0.77)
F	fraction of CH4 in landfill gas (IPCC default is 0.5)

DOC can also be estimated as follows:

DOC = 0.4 (A) + 0.17 (B) + 0.15 (C) + 0.30 (D)

where,

A	per cent waste that is paper and textiles
B	per cent waste that is garden waste, park waste or other non-food organic putrescibles
C	per cent waste that is food waste
D	per cent waste that is wood or straw

Baseline emission should not include methane emissions captured and removed to meet the national or local safety requirement or legal regulations. For example, if local or national safety regulations on landfill sites mandate capture and removal of 10% of methane, then the baseline would be only 90% of the methane emission, or

BEy = 0.9x Qbiomass x CH4_IPCCdecay x GWP_CH4