PETROFED

Petroleum Federation of India

Clean Development Mechanism – Opportunities in Indian Downstream Oil & Gas Sector

June 2006

A study by PetroFed in association with Member Company and Knowledge Partner

PRICEWATERHOUSECOOPERS

Title	"Clean Development Mechanism - Opportunities in Indian Downstream Oil and Gas Sector" A publication of Petroleum Federation of India
Address for Correspondence	A. K. Arora Director General Petroleum Federation of India (PetroFed) 1st Floor, Indian Oil Bhawan, 1, Sri Aurobindo Marg, Yusuf Sarai, New Delhi – 110 016 Phone: +91-11-2653 5697, 2653 7069 Fax: +91-11-2698 4840 E-mail: petrofed@petrofed.org
Acknowledgements	Petroleum Federation of India (PetroFed) is presenting this publication in knowledge partnership with its member company PricewaterhouseCoopers Private Limited (PwC). PetroFed was assisted by Oil & Gas Sustainable Business Solutions Group of PwC, a speciality practice established to help companies in the creation of sound climate change strategies that will maximize the value of untapped carbon assets and implement mitigation strategies for companies with a carbon exposure. We are thankful to PwC for their efforts.
Copyright	The data or other contents in part or full, shown in this publication cannot be copied, reproduced, republished, uploaded, posted, printed, stored, transmitted or distributed in any other way for non-personal or commercial use without obtaining prior permission of PetroFed in writing. Any alteration of the material or use of the material contained in this publication in violation of the Copyright laws is strictly prohibited.
Disclaimer	Interpretation and Usage: This publication "the Publication' is intended to provide general guidance on matters of interest only. The application of inference drawn in the publication can vary widely based on the facts involved. All the contents of the publication have been collated from various official sources specifically mentioned herein and other publicly available information disseminated for research, analysis, review and reference purposes. While we have made reasonable attempt to ensure that the information contained in this Publication has been obtained from reliable sources, PetroFed is not responsible for any errors or omissions, or for the results obtained from the use of this information. This information is for guidance only and should not be regarded as substitute for appropriate professional advice. PetroFed accepts no liability with regard to the information herein or any action that may be taken by readers of this publication. Neither PetroFed nor any individuals associated with this publication shall be required, by reason of this publication, to provide testimony to appear in Court or at other legal proceedings, unless specific arrangements to do so have been made. All information in this publication is provided "as is", with no guarantee of completeness, accuracy, timeliness or of the results obtained from the use of this information, and without warranty of any kind, express or implied, including, but not limited to warranties of performance, merchantability and fitness for a particular purpose. In no event will Petroleum Federation of India and/or PricewaterhouseCoopers Pvt. Ltd. or their employees thereof be liable for any decision made or action taken in reliance on the information in this Publication or for any consequential, special or similar damages, even if advised of the possibility of such damages.

Petroleum Federation of India

The Petroleum Federation of India is a Registered Society of Indian and International Companies/ Associations in the hydrocarbon sector to promote the interest of members in line with Public/ National policies through a self regulatory environment with consumer interest in sight.

It acts as an oil industry interface with government, regulatory authorities, public and representative bodies of traders. It helps in resolution of issues and facilitates evolution of hydrocarbon related policies and regulations and their implementation. It represents the industry on Government bodies, committees & task forces.

PetroFed promotes energy conservation, health, safety & environment and helps to optimise resource utilisation of members. It organizes seminars, conferences, workshops, training programmes, lectures and brings out technical publications. It produces a quarterly journal.

A.K. Arora
Director General
Phone: +91-11-2653 5697, 2653 7069
Fax: +91-11-2696 4840
E-mail: petrofed@petrofed.org

PricewaterhouseCoopers

PricewaterhouseCoopers Pvt. Ltd. is one of the largest and most reputed professional services network in the country. PricewaterhouseCoopers specialists from tax and advisory teams connect their thinking, experience and solutions to build public trust and enhance values for clients and their stakeholders.

The Oil & Gas Industry Group within PricewaterhouseCoopers works with national and international companies in public and private sector to provide industry focused solutions.

PricewaterhouseCoopers is privileged to work with an unrivalled Oil and Gas industry client base, who value the rigorous, practical approach, characterised by a detailed understanding of individual client issues and by deep industry knowledge and experience. Strategies to develop services and delivery methods that fully meet client's needs have enabled networks of highly skilled professionals to be built around the clients. The success in meeting client's business challenges is mirrored in the growth seen by Oil & Gas companies.

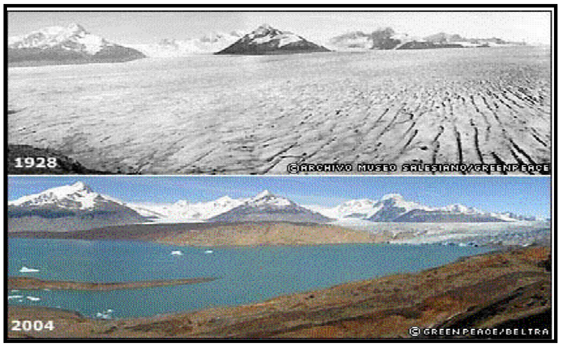
PricewaterhouseCoopers have offices in Bangalore, Kolkata, Chennai, Hyderabad, Mumbai, New Delhi, Bhubaneshwar and Pune.

N. N. Gupta
Head-Oil & Gas Practice
Tl.: +91 (11) 2321 6023
Fax: +91 (11) 2321 0594
E-mail: oil.gas@in.pwc.com

Contents

Foreword

According to a study published in the journal "Conservation Biology", global warming ranks among the most serious threats to our biodiversity, and as per another study, it could become a top cause of extinction of thousands of species of plants and animals in the coming decade. Published photographs of its impacts on our glaciers show remarkable melt-down from 1928 to 2004.



Not surprisingly, at the 1992 Earth Summit in Rio de Janeiro, over 150 countries signed the United Nations Framework Convention on Climate Change (UNFCCC) as part of an effort to "stabilize greenhouse gas concentrations at a level that would prevent dangerous anthropogenic changes to the climate system". To forward this objective, the UNFCCC called upon developed countries and countries with economies in transition (Annex I Parties) to return to 1990 emission levels in the year 2000.

Under Article 4(2) of the Convention, Parties are provided the opportunity to meet these reduction obligations "jointly with other Parties". This and subsequent deliberations paved the way for agreement on the text of the Kyoto Protocol in 1997 and its entering into force in February 2005. Indian industries have started moving much ahead of 2005 in anticipation of the prospects of Clean Development Mechanism (CDM), and many have reaped the benefits and more are in the process.

The awareness on the CDM processes has grown over the years, and many of our members have also got themselves motivated. We, at Petroleum Federation of India, have proactively watched the local and global developments on CDM opportunities, and today through this study, have tried to at least forecast the likely CDM potential available to our members in the downstream oil and gas sector in terms of type of opportunities and scale of CDM revenue that could be realized. As on date, Indian CDM projects continue to be rated as preferred CER generators and India is rated as the most preferred CDM destination followed by China and Brazil. Hence, we see immense opportunities for our member oil companies to derive benefits from the CDM process and also reduce global warming potential of their operations and activities.

In this study, we have partnered with our member PricewaterhouseCoopers to assess the CDM potential, undertake review at a candidate refinery and suggest a way forward for our sector to realize additional monetary benefits and better management acceptance to potential initiatives which are currently perceived to face prohibitive hurdles to their implementation.

We encourage our members to assimilate findings of this study and seek any clarifications and guidance for developing potential opportunities in their operations into successful CDM projects. We hope our efforts will result in fruitful ventures by our members.

A. K. Arora
Director General
Petroleum Federation of India
May 2006

Executive Summary

Overview

CDM is established under Article 12 of the Kyoto Protocol with dual goals of assisting developing countries (NON-ANNEX I countries) in achieving sustainable development, and assisting industrialized countries (ANNEX I countries) in meeting a portion of their emission reduction commitments under the Protocol. To be certified under the CDM, project developers must demonstrate that the project: (1) has the approval of the country hosting the project and (2) will result in real, measurable, and long-term emission reductions that are *additional* to any that would occur in the absence of the project.

In July 2001, officials from 178 countries attending the Sixth Conference of the Parties to the UNFCCC in Bonn, Germany, reached an agreement on four key issues:

1. Financing to developing countries,
2. Trading mechanisms,
3. Forestry and land use, and
4. Compliance rules.

Although the U.S. was the leading emitter of GHGs in 1990, the Kyoto Protocol only requires ratification by 55 nations representing 55% of the 1990 GHG emissions in industrialized countries to enter into force. The agreement reached in Bonn lays the groundwork for achieving the requisite number of ratifications to bring the treaty into force, even without U.S. participation. Taking advantage of this agreement, a number of companies globally as well as in India have availed of CDM benefits and many are in the process. This assessment is a continuation with such achievements in the Indian business environment.

To conform to Kyoto Protocol commitments, EU countries have allocated emission permits to facilities in identified sectors and a trading mechanism of such allowances called EU-ETS has been started. The emission allocations are for two periods: NAP 1 (2005 – 2007) and NAP 2 (2008 – 2012). The NAP 1 allocations and acceptance requirements beginning January 2000 has kick-started the carbon markets. Buoyed by the EU-ETS and Kyoto mechanisms, in countries that have ratified and that have not ratified the Kyoto Protocol, the voluntary carbon markets have emerged. The active carbon markets today point out to emergence of carbon constrained economy.

Objective of the Assessment. PetroFed intends to assist its member Indian companies in the downstream oil and gas business sector to identify potential CDM projects across their operations, and develop a strategy and action plan for availing benefits out of their greenhouse gas emission reduction initiatives and responses in carbon constrained economy. It also intends to provide guidance to identify and develop CDM projects in their facilities and operations through a broad assessment of CDM revenue for this sector.

Approach to the Assessment. PetroFed selected one its member companies as a candidate refinery (CR) for assessment by PricewatehouseCoopers team for CDM project identification. The CDM opportunity identification assessment at the CR included crude transportation and storage, refinery processes and utilities, and product storage and transportation. In addition, desk top study was completed to understand and evaluate CDM potential for the downstream oil and gas sector including natural gas transportation and distribution. Based on this assessment, this industry document has been prepared for the benefit of member companies of PetroFed.

Key Findings of the Assessment and Way Forward

The different types of CDM opportunities available to a sector vary in nature, scale and location, since no two businesses in the same sector are similar to each other. The potential opportunities would also differ on the basis of what is the existing technology used in a process, its efficiency and costs, age or vintage of the technology in use, and if a better one can be utilized to retrofit the existing or replace it. The assessment of opportunities should also be seen in the background of CDM eligibility criteria, and whether these opportunities are actually 'business as usual' scenarios which would have occurred irrespective of the project's barriers and hurdles. Due to these reasons, it is highly unlikely that any business in the sector will bring forward a CDM project of similar scale as any other business operating in the same sector; however, similar types of opportunities do exist. Therefore, the case presented herein can be used as an exploration tool for identifying CDM projects.

The broader types of CDM opportunities that exist are in: (1) Fugitive emission reduction measures during natural gas transmission and distribution operations, (2) energy efficiency measures, (3) process improvements measures, (4) improved management practices for different products, (5) reducing fugitive methane emissions from various sources and also recovering methane as an useful energy source, and (6) switch from solid or liquid fuels to gaseous fuels for power and/or steam generation.

Because of the variety in scale and nature of opportunities that can only be assessed on case-to-case basis, no project-specific CDM potential could be attempted. However, based on published information by the Ministry of Petroleum and Natural Gas (MoPNG) and Intergovernmental Panel on Climate Change (IPCC), CDM potential for the sector, separately for natural gas transmission and distribution, and crude oil to product cycles including storage and distribution, have been estimated. Step-wise information is provided on how a member company can identify CDM opportunities in its operations, structure these for registration as eligible CDM projects and finally transact these CERs with potential buyers in developed countries.

Information is also provided on how each member oil company may, either independently or in partnership with another member company, institute processes for identification and development of CDM projects. The partnerships could result in transfer of specific technical knowledge about operations, practices, type of financial hurdles perceived by company managements while deciding on a project, etc.

It is important that all initiatives identified as potential CDM project activities at the member organizations of PetroFed are looked into expeditiously, keeping the following issues in mind:

- ✓ credit is available if project had started after 1 January 2000, validation was initiated by DOE within 31 December 2005, and registration by UNFCCC is completed within 31 December 2006. Voluntary market (at low prices) is still available for those projects that have missed the above deadlines;

- ✓ structure initiatives into CDM opportunities as soon as possible; plan based on type of project/ technology/ hurdles; indicative current estimates are: time-frames (6 – 18 months) and costs (Rs. 15 – 25 lakhs);

- ✓ plan ahead for 2nd Commitment Period (post 2012) and strategize industry approach to prepare the sector to reap future benefits;

- ✓ strategize approach to future markets under Asia-Pacific Initiatives; and

- ✓ strategize actions for tapping voluntary markets.

It is expected that PetroFed could play an important role in knowledge sharing, capacity building and process facilitation functions on behalf of the member companies. PetroFed could also act as the industry representative for this sector and discuss with the government, UNFCCC, stake-holders, technology suppliers, etc. on how to maximize CDM benefits for GHG mitigation initiatives undertaken or to be undertaken in the sector.

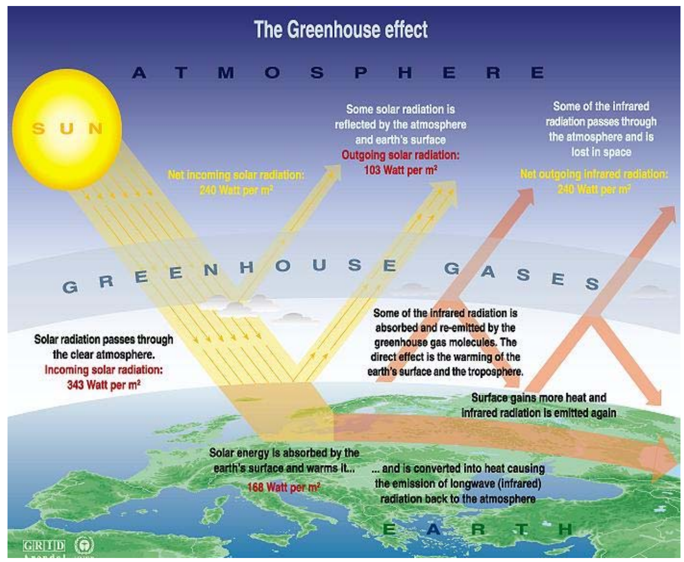
1

Clean Development Mechanism: An Overview

1.1 What is "Greenhouse Effect"?

One of the prime supports for life on earth is energy received from the sun that arrives mainly in the form of visible light. Scientific research has established that about 30% of the energy received from sunlight is reflected back into space by the earth's outer atmosphere while the balance reaches the earth's surface as short wave-length radiation. The earth must shed this energy into space at the same rate at which it absorbs/ receives it. The amount reaching the earth's surface is again reflected in the form of a calmer, more slow-moving form of energy called infrared radiation. This radiation eventually disperses into space by air currents in the earth's atmosphere as long wave-length infra-red radiation. However, such escape is delayed by the presence of greenhouse gases (GHG) such as water vapour, carbon dioxide, ozone, methane, etc. in the atmosphere. Many of the GHGs are result of anthropogenic actions in the recent centuries of industrialization when climate change impacts of these activities were neither fully understood nor were a priority issue.

The delay in escape of solar energy already received leads to a phenomenon called "Global Warming" resulting in remarkable changes to many physical and chemical characteristics of the earth's climate.



Though the climate does not respond immediately to external changes, but after 150 years of industrialization, global warming has momentum, and it will continue to affect the earth's natural systems for hundreds of years in the future. Research indicates that:

- ✓ GHGs act as glass roof of a greenhouse or blanket preventing radiation of energy from earth's surface to space;
- ✓ anthropogenic (human) activities are making this blanket grow "thicker" thereby trapping more energy in the atmosphere;

- ✓ GHG build up in the atmosphere is growing faster;
- ✓ such GHG build up known as the *"enhanced greenhouse effect"*, is a warming of the earth's surface and lower atmosphere[1]; and
- ✓ even a small rise in temperature will be accompanied by changes in climate, such as in cloud cover, precipitation, wind patterns, and the duration of seasons; such changes lead to secondary impacts such as increase in global atmospheric temperatures, melting of ice-bergs, changing cropping pattern changing disease pattern, etc., that have direct and indirect consequences on the life on earth.

Of the various GHGs, it has been established that carbon dioxide is responsible for over 60% of the *"enhanced greenhouse effect"*. Burning coal, oil, and natural gas at a rate that is much faster than the speed at which these fossil fuels were created is releasing the carbon stored in the fuels into the atmosphere and thereby upsetting the carbon cycle, the millennia-old, precisely balanced system by which carbon is exchanged between the air, the oceans, and land vegetation.

1.2 Global Action on Climate Change

In 1979, for the first time in the international public area, any scientific evidence of human interference with the climate had emerged; this was the First World Climate Conference (WCC). Public awareness on the imminent danger continued to increase in the 1980s forcing political entities such as governments became more concerned about climate issues. Based on a proposal by the Government of Malta, the United Nations General Assembly in 1988 adopted resolution 43/53, urging: "…protection of global climate for present and future generations of mankind".

Again in 1992, at the Earth Summit in Rio de Janeiro (Brazil), over 150 countries signed the United Nations Framework Convention on Climate Change (UNFCCC) as part of a combined effort to "stabilize GHG concentrations at a level that would prevent dangerous anthropogenic changes to the climatic system'. The further this objective, the UNFCCC called for developed countries and countries with economies in transition (EIT), to return to the 1990 emission levels in the year 2000. Under Article 4(2) of the Convention (i.e., UNFCCC), the above mentioned Parties are provided with the opportunity to meet reduction obligations 'jointly with the other Parties'.

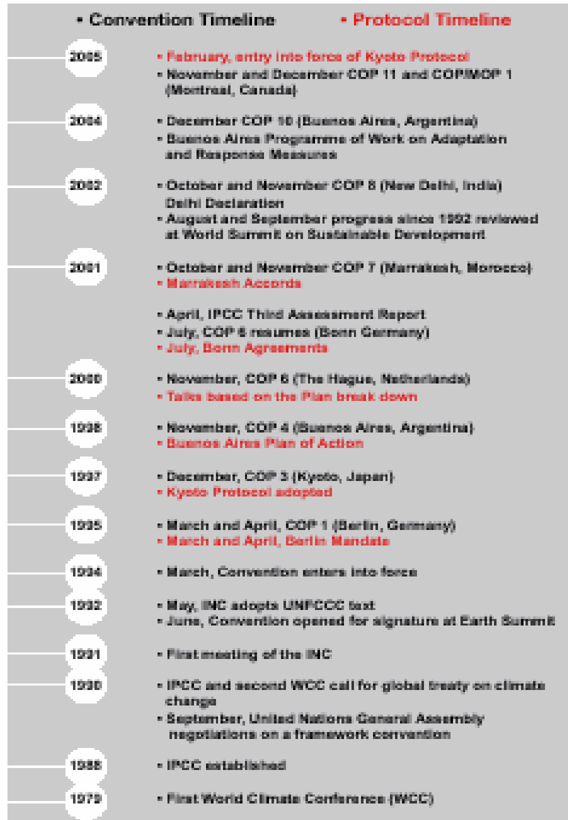
[1] Computer simulations models estimated average global temperature rise by 1.4 to 5.8^{o}C by the year 2100.

1.3 Emergence of Kyoto Protocol

A series of activities at the international level continued *(refer to attached box)* and culminated in the preparation of the Kyoto Protocol (KP) in December 1997 and its entry into force in February 2005.

Some of the important milestones achieved between the 1st WCC and entry into force of the Kyoto Protocol, were:

- ✓ 1st meeting of the Intergovernmental Negotiating Committee (INC) in 1991;
- ✓ adoption of the text of the UNFCCC and its coming into force in 1992;
- ✓ 1st Conference of Parties (COP 1) at Berlin in 1995; and
- ✓ Marrakesh Accords in 2001.



The provisions in the KP[2] concern all GHGs not covered by the 1987 Montreal Protocol to the United Nations Convention on Protection of the Ozone Layer. The focus of the KP is on the following six:

- Carbon dioxide (CO_2);
- Methane (CH_4);
- Nitrous oxide (N_2O);
- Hydrofluorocarbons (HFCs);
- Perfluorocarbons (PFCs); and
- Sulphur hexafluoride (SF_6).

The first three GHGs listed above are estimated to account for 50, 18 and 6 per cent, respectively, of the overall global warming effect arising from anthropogenic human activities. The HFCs are used as replacements for ozone-depleting substances such as chlorofluorocarbons (CFCs) currently in phase out under the Montreal Protocol. PFCs are typically emitted in the aluminium smelting process. SF_6 is used in some industrial processes and in electric equipment.

The global warming potential is the impact a GHG has to global warming. By definition, CO_2 is used as reference case, hence it always has the GWP of 1. The GWP changes with time, and the Intergovernmental Panel on Climate Change (IPCC) has suggested using 100-year GWP for comparison

[2] The text of the KP is available at http://unfccc.int/resource/docs/convkp/kpeng.pdf.

purposes. The current GWPs[3] (as per 3rd Assessment Report of IPCC) are indicated below.

GHG	**GWP**
CO_2	1
CH_4	23
N_2O	296
HFCs	120 – 12,000
PFCs	5,700 – 11,900
SF_6	22200

For KP to enter into force, at least 55 Parties to the Convention needed to ratify it, including enough industrialized countries listed in the Convention's Annex I to encompass 55% of that group's carbon dioxide emissions in 1990. The first Parties ratified the Protocol in 1998 and the required target was met with the ratification by the Russian Federation on 18 November 2004. After the prescribed 90-day countdown, the KP came into force on 16 February 2005.


The Japan Times
Conference adopts Kyoto Protocol
Greenhouse gas emissions to be cut by average of 5.2%
KYOTO COP3
Kyoto convention's success open to debate

[3] http://www.fluorocarbons.org/en/info/brochures/fact_09.html

Though GHG reducing initiatives started in anticipation of the Russian ratification, these picked momentum after the ratification that set ground to engineer efforts at collectively planning and implementing methods for reducing GHG emissions over agreed time-frame.

The KP divides countries into three main groups with differing commitments as elaborated below.

1. **ANNEX I Parties** include the industrialized countries that were members of the OECD (Organisation for Economic Co-operation and Development) in 1992, plus EIT countries (the EIT Parties) including the Russian Federation, the Baltic States, and several Central and Eastern European States. ANNEX I Parties must adopt climate change policies and measures with the aim of reducing their GHG emissions to 1990 levels by the year 2000. This provision obliges them to set an example of firm resolve to deal with climate change. The Convention grants EIT Parties "flexibility" in implementing commitments, on account of recent economic and political upheavals in those countries. Several EIT Parties have exercised this flexibility to select a base year other than 1990 for their specific commitment, to take account of intervening economic changes that led to big cuts in emissions.

2. **ANNEX II Parties** consist of the OECD members of ANNEX I, but not the EIT Parties. They are required to provide financial resources to enable developing countries to undertake emissions reduction activities under the Convention and

to help them adapt to adverse effects of climate change. In addition, they have to "take all practicable steps" to promote the development and transfer of environmentally friendly technologies to EIT Parties and developing countries. Funding provided by ANNEX II Parties is channeled mostly through the Convention's financial mechanism.

3. **NON-ANNEX I** Parties are mostly developing countries. Certain groups of developing countries are recognized by the Convention as being especially vulnerable to the adverse impacts of climate change, including countries with low-lying coastal areas and those prone to desertification and drought. Others (such as countries that rely heavily on income from fossil fuel production and commerce) feel more vulnerable to the potential economic impacts of climate change response measures.

In addition to the above three categories of countries, those 48 Parties classified as least developed countries (LDCs) by the United Nations are given special consideration under the Convention on account of their limited capacity to respond to climate change and adapt to its adverse effects. All Parties are urged to take full account of the special situation of LDCs when considering funding and technology transfer activities.

Commitments under the Kyoto Protocol. All Parties comprising those countries that have ratified, accepted, approved or acceded to the KP are subject to general commitments to respond to climate change. They agree to compile an inventory of their GHGs and submit reports - known as national communications[4] on actions they are taking to implement the objectives of the KP. To address such actions, the Parties must prepare national programmes containing:

- climate change mitigation measures;
- provisions for developing and transferring environmentally friendly technologies;
- provisions for sustainably managing carbon 'sinks'[5];
- preparations to adapt to climate change;
- plans for climate research, observation of the global climate system and data exchange; and
- plans to promote education, training and public awareness relating to climate change.

The focus of the KP is on the following:

✓ **commitments,** including legally binding emission targets and general commitment;

✓ **implementation,** including domestic steps and three novel implementing mechanisms;

---

[4] In India, NATCOM under the Ministry of Environment and Forests (MoEF) is responsible for preparing this inventory.

[5] A term applied to forests and other ecosystems that can remove more GHGs from the atmosphere than they emit.

- ✓ **minimizing impacts on developing countries,** including use of the Adaptation Fund;

- ✓ **accounting, reporting and review,** including in-depth review of national reporting; and

- ✓ c**ompliance,** including a Compliance Committee to assess and deal with problems.

Institutions. The supreme body of the Climate Change Convention is its Conference of the Parties (COP). It meets every year to review the implementation of the Convention, adopt decisions to further develop the Convention's rules, and negotiate new commitments. The following two subsidiary bodies meet at least twice a year to steer preparatory work for the COP.

(1) Subsidiary Body for Scientific and Technological Advice (SBSTA) provides advice to the COP on matters of science, technology and methodology, including guidelines for improving standards of national communications and emission inventories.

(2) Subsidiary Body for Implementation (SBI) helps to assess and review the Convention's implementation, for instance by analyzing national communications submitted by Parties. It also deals with financial and administrative matters.

Secretariat services. A secretariat staffed by international civil servants and hosted since 1996 by Germany in Bonn supports all institutions involved in the climate change process, particularly the COP, the subsidiary bodies and their Bureaux. Its mandate is to make arrangements for the sessions of the Convention bodies, to help Parties fulfill their commitments, to compile and disseminate data and information, and to confer with other relevant international agencies and treaties. The **Global Environment Facility (GEF)** and the **IPCC** work with the Convention, but are not attached to it. The IPCC is a crucial source of information on climate change. At five-year intervals it publishes comprehensive progress reports on the state of climate change science, the latest of which *(the Third Assessment Report)* appeared in 2001.

The Greenhouse Gas Information System[6]. The UNFCCC secretariat has developed a GHG Information System t o manage and blend the abundant flows of data emerging from reporting and review processes, as the basis for the provision of information to the COP and for various types of data analysis. It is updated twice a year and is continuously supported and enhanced to ensure that it offers reliable data suitable for a wide range of analyses.

KP roles ahead. In July 2001, at COP 7, international policy makers from 178 countries reached an agreement on the rules and requirements for implementing the KP. This agreement laid the groundwork for countries to begin the ratification process and bring KP into force. In anticipation of the success of the KP process, many countries and private sector corporations started taking progressive steps in combating climate change. Such steps included development of European Union wide domestic trading system on KP covered GHGs, voluntary emission reduction (VER) targets by major Fortune 500

[6] http://ghg.unfccc.int

companies, private sector investments by companies in carbon offset projects domestically and internationally, and launching of the Prototype Carbon Fund by the World Bank.

Kyoto Mechanisms. The KP provided three cost-effective mechanisms for climate change mitigation by opening avenues for reducing GHG emissions and enhancing carbon 'sinks'. These mechanisms are thought to be cost-effective because even if the associated costs for implementing any of the mechanisms varies from region to region, the effect on global atmosphere would be same, and hence the implementation location can be planned in advance.

The KP compliance targets could be met by ANNEX I Parties through any of the following three market-based mechanisms[7]:

1. International Emission Trading (IET)
2. Joint Implementation (JI)
3. Clean Development Mechanism (CDM).

The above mechanisms are designed to enable the ANNEX I Parties to achieve a portion of their emission reduction targets through co-operative efforts with other Parties identified in the Convention. Whereas IET and JI are limited to emission trading between ANNEX I Parties, CDM requires project participation between ANNEX I and NON-ANNEX I Parties. In addition, both JI and CDM are project based forms of emission trading, whereas IET is budget-based and allows countries to trade portions of their emission budgets.

At this stage it is difficult to quantify the exact impact of any or more of the three KP mechanisms on global GHG emissions, but provides the first step to achieving stabilization of GHG concentrations in the atmosphere at a safer level.

1.4 Clean Development Mechanism

According to the Kyoto Protocol "The purpose of the clean development mechanism shall be to assist Parties not included in ANNEX I in achieving sustainable development and in contributing to the ultimate objective of the Convention, and to assist Parties included in ANNEX I in achieving compliance with their quantified emission limitation and reduction commitments under Article 3".

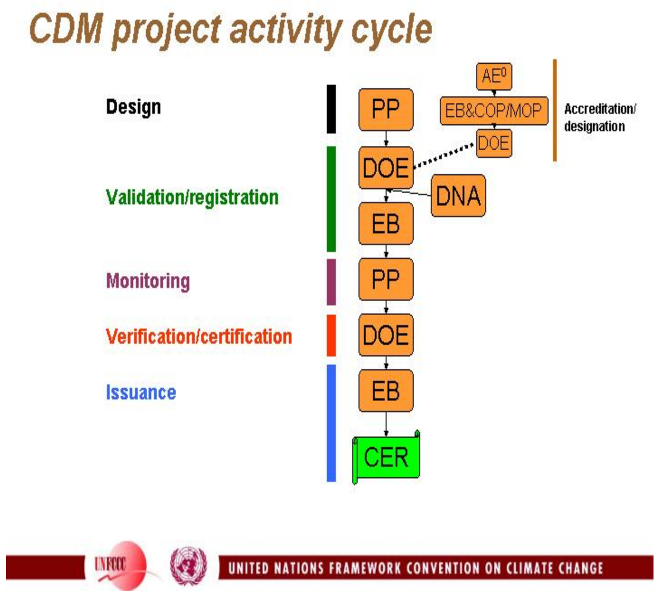
CDM is a process where developing country participants such as Indian enterprises can participate along with ANNEX I participants. As a NON-ANNEX I Party, India is eligible to host CDM projects and generate certified emission reductions (CER) for trading with ANNEX I Parties.

CDM is anticipated to catalyse investments and technology transfer to developing countries who do not have GHG reduction compliance commitments under the KP but opportunities to promote sustainable development. All of these are to be additional to the finance and technology transfer commitments of ANNEX II Parties. Any public funding to a CDM project activity should not be a diversion

[7] IET is outlined in Article 17, JI is outlined in Article 6 and CDM is outlined in Article 12 of the KP.

of official development assistance (ODA).

The CDM projects must lead to real, measurable and long-term climate benefits in the form of emission reductions or removals that are additional to any that would have occurred without the project. The CDM projects must be based on appropriate, transparent and conservative *baselines*[8] and must have in place a rigorous *monitoring plan* to collect accurate emissions data as per approved methodologies. The CDM Executive Board (CDM EB) has accredited independent organizations, known as Designated Operational Entities (DOEs), to play a key role in the CDM project cycle. The CDM process cycle is depicted here.



[8] The baseline for a CDM project activity is the scenario that reasonably represents the anthropogenic emissions by sources of GHG that would occur in the absence of the proposed project activity. A baseline shall cover emissions from all gases, sectors and source categories listed in Annex A (of the Kyoto Protocol) within the project boundary. A baseline shall be deemed to reasonably represent the anthropogenic emissions by sources that would occur in the absence of the proposed project activity if it is derived using a baseline methodology referred to in paragraphs 37 and 38 of the CDM modalities and procedures.

1.5 Sectoral Scope in CDM

The following 13 scopes for CDM project activities were defined by the CDM EB; it is based on the list of sectors and sources contained in Annex A of the KP. The scopes are relevant in the validation and verification process as a DOE must have a valid accreditation for each sector it wants to operate in. Also the baseline and monitoring methodologies are organized according to these scopes:

1. Energy industries (renewable - / non-renewable sources)
2. Energy distribution
3. Energy demand
4. Manufacturing Industry
5. Chemical Industry
6. Construction
7. Transport
8. Mining and Mineral Production
9. Metal Production
10. Fugitive emissions from fuels (solid, oil, gas)
11. Fugitive emissions from production and consumption of halocarbons and sulphur hexafluoride
12. Solvent used
13. Waste handling and disposal

1.6 CDM Registry

The KP provides for the establishment and maintenance of a CDM Registry by the Executive Board on behalf of the NON-ANNEX I Parties. It is a standardized electronic database to ensure accurate accounting of CERs. According to the Marrakech Accords, the CDM Registry is a platform on which the following can happen:

- ✓ CERs are issued and forwarded to project participants;
- ✓ CERs are held by NON-ANNEX I Parties;
- ✓ the share of proceeds managed;
- ✓ CERs and other tradable units under KP may be cancelled (to make up for over issuance of CERs based on erroneous DOE verification); and
- ✓ Information is made publicly available.

Only CERs may be held in CER Registry accounts. In addition, this Registry has to perform business, administrative and infrastructure functions, e.g., functioning in a network with national registries and International Transaction Log (ITL).

The following issue exists regarding operation of the CDM Registry:

- **Accounts for ANNEX I Parties.** Such Parties and their entities will have accounts in the CDM Registry as long as ITL and national registries are not operational.

1.7 Impact of CDM on Indian Businesses

Unlike many other developing countries, the Indian businesses have started early to understand and develop projects that have associated GHG emission reductions and also qualify as eligible CDM projects. Awareness on the subject has increased during past five years through dissemination of information by industry associations, CDM experts and advisors, media and experience shared by the first movers.

Some illustrative statistics are provided under this section of the report indicate that Indian enterprises have been major beneficiaries of the CDM process.

Of a total of around 184 project activities registered globally (as on 18 May 2006), 28% of the projects are from India constituting 15.26% of the total annual CER volume to be generated from all registered projects. The average annual CER generation from all 184 registered projects will be about 54,212,448 tonne equivalents of carbon dioxide reductions.

The potential CDM project opportunities available to Indian enterprises, including the oil refining sector, can be broadly generalized under the following categories, though this list is not exhaustive in its depiction of potential CDM opportunities:

- Energy efficiency
- Steam optimization
- Equipment replacement & process improvements
- Control of Fugitive Emissions of Methane
- Fuel shift (liquid fuels to gaseous fuels including hydrogen in process heating, steam generation, power generation, etc.) and
- Use of by-product or waste products.

Realizing the potential benefits, some corporations in the 'Indian Downstream Oil and Gas Sector[9]' have already initiated activities to structure their efforts as CDM projects.

The CERs generated from projects in India have seen the following modes of transaction in the international market as explained later under this section of the report:

1. buying by banks (like World Bank - IFC, and some private banks);
2. buying by financial organizations and brokering agencies; and
3. industries in ANNEX I countries who would be directly using the CERs.

The major funds involved in the procurement of CERs are:

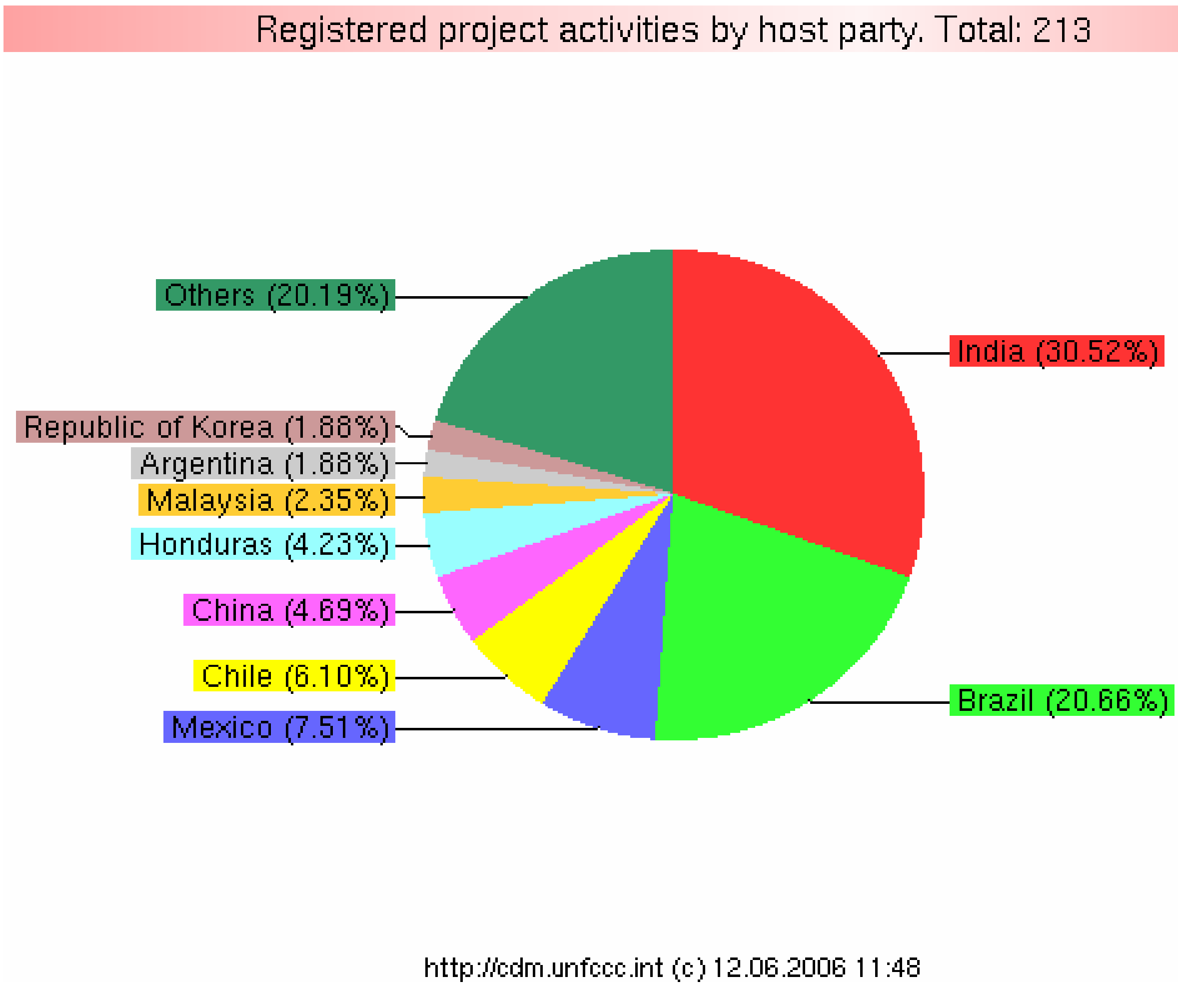
- **Prototype Carbon Fund (PCF)** with contribution of US$ 180 million from six governments and 17 companies in ANNEX I countries;
- Community Development Carbon Fund (**CDCF**) with first tranche capitalization of US$ 128.6 million by nine governments and 15 corporations/ organizations;
- Bio-Carbon Fund (**BioCF**) mobilized by the World Bank with a total capital of US$ 53.8 million;
- The Netherlands CDM and JI Facilities (**NCDMF**);
- Italian Carbon Fund (**ICF**);
- Danish Carbon Fund (**DCF**);
- Spanish Carbon Fund (**SCF**)

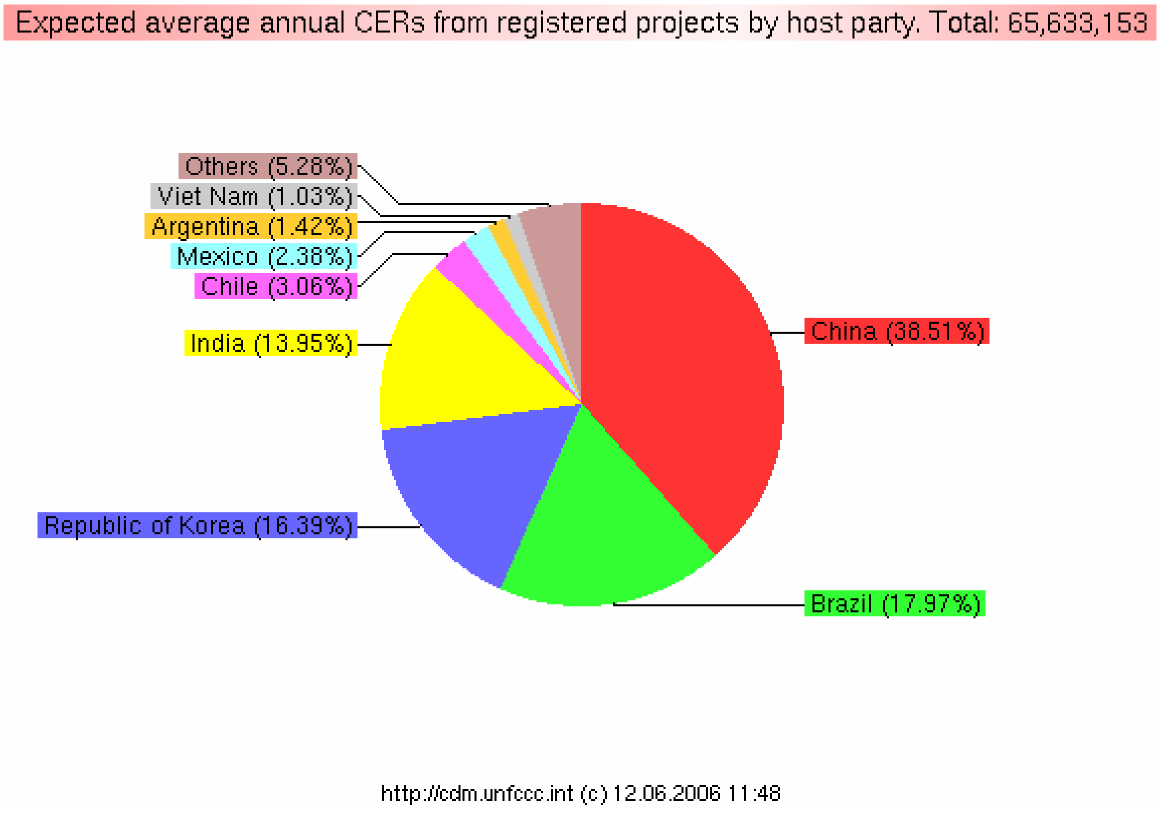
[9] This sector is defined here to include "post exploration down-stream gas transportation, crude oil transportation on land and its storages, refinery activities, product storages, transportation and distribution, and all associated utilities and support facilities".

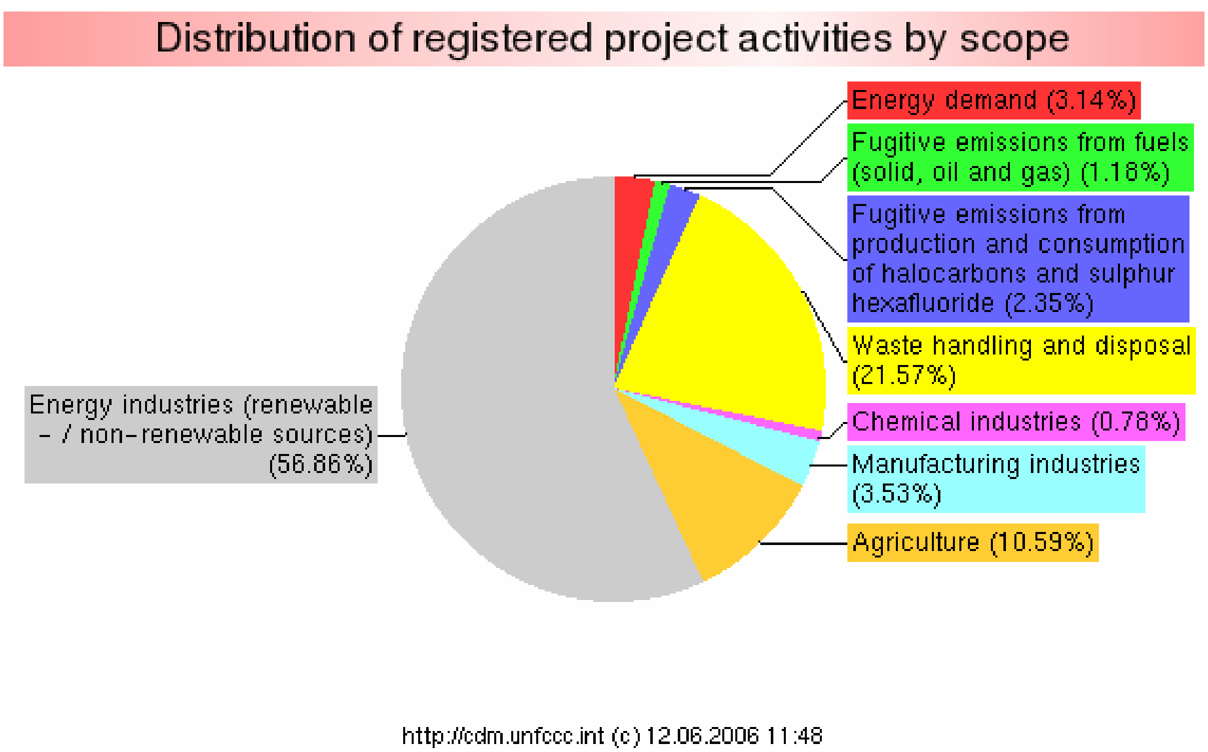
- Dutch Government (**CERUPT Programme**);
- **Finnish CDM/JI Pilot Programme** (€20 million);
- **Sweden International Climate Investment Programme** CDM;
- **Austria JI/CDM Procurement Procurement Programme**; and
- Spanish Carbon Fund.

The forms of transactions generally included forward contracts whereby a unit price was agreed for each CER provided the relevant project that would generate the CERs get registered with the CDM EB. However, there have been also transactions where contracts have been prepared after registration of the projects.

Section 1.8 provides insights into CER market dynamics and price movements, risks and opportunities, and more importantly markets that can be accessed by Indian Businesses.




Expected average annual CERs from registered projects by host party. Total: 65,633,153
Others (5.28%)
Viet Nam (1.03%)
Argentina (1.42%)
Mexico (2.38%)
Chile (3.06%)
India (13.95%)
Republic of Korea (16.39%)
China (38.51%)
Brazil (17.97%)
http://cdm.unfccc.int (c) 12.06.2006 11:48


Distribution of registered project activities by scope
Energy demand (3.14%)
Fugitive emissions from fuels (solid, oil and gas) (1.18%)
Fugitive emissions from production and consumption of halocarbons and sulphur hexafluoride (2.35%)
Waste handling and disposal (21.57%)
Chemical industries (0.78%)
Manufacturing industries (3.53%)
Agriculture (10.59%)
Energy industries (renewable - / non-renewable sources) (56.86%)
http://cdm.unfccc.int (c) 12.06.2006 11:48

1.8 CDM at Market Place

The price of CERs like any other tradable commodity is linked to its demand in the market. The following factors are deemed to determine present and future CER prices, as per 'Point Carbon[10]'.

(1) **Price signal for emission reductions beyond 2012.** The absence of an international agreement for post-2012 (i.e., after 1st Commitment Period) has significantly reduced demand for CERs beyond vintage year 2012, thereby making many projects uneconomic and reducing supply.

(2) **AAU's Supply.** The level of actual supply of surplus Assigned Amount Units[11] to be compliance requirements is still largely unknown. The EU, Japan and Canada have already indicated that they will not purchase surplus AAUs *(hot air)* that result from economic contraction unless they are "greened" (i.e., linked to emission reduction activities, whether directly or indirectly). Efforts to create Green Investment Schemes (GIS) in EIT countries (e.g., Russia and Bulgaria) are underway, but little is yet known regarding the supply of greened AAUs meeting buyer country criteria. It is also not clear to what extent will some countries like Russia would seek to restrict the quantity of AAUs in the market by banking them.

(3) **Japan's role in KP.** If any mandatory trading programme is created, Japan will have a large market, and the private sector is likely to account for a large portion of its international GHG purchases.

(4) **Canada's role in KP.** Like Japan, this market is yet not clear.

(5) **Development of ITL.** This is yet not ready for receipt and transfer of CERs across country registries and buyer accounts, and is expected to be operational in 2007.

(6) **Other Factors.**

- quantity of cost-effective abatement options available to participants in the carbon market;
- likely shortfall of emissions due to the tightness of the caps and the likely availability of credits from CDM and JI (project-based mechanisms);
- impact of *'hot air'* (particularly from Russia and Ukraine) entering the market;
- range of possible fuel prices which impact the degree of load shifting between coal and gas as well as the new entrant price for investments in CCGT plants coming online in 2008-2012; and
- factors impacting the timing of the emergence of a global LNG

[10] Point Carbon is the leading provider of independent analysis, forecasting, market intelligence and news for the power, gas and carbon emissions markets.

[11] The assigned amount (AA) is the total amount of GHG that each of the 39 countries with compliance requirements (ANNEX B) under KP is allowed to emit during the first commitment period. An AAU is a tradable unit of 1 tCO_2e.

market resulting in a de-linking of oil to gas prices.

However, the two most critical determinants of current and future CER prices (whether high or low) are: (1) flow of surplus AAUs *(hot air)* from EIT countries to meet the demand in the European Union and other countries, and (2) the ability of the power generation sector to reduce CO_{2e} emissions. In addition, the impact of inaccuracies in NAP estimates could also impact the CER prices.

It is also to be understood that due to the common but differentiated responsibilities amongst Parties to the KP, the ANNEX I countries have to put in place policies and programmes in their countries to meet the commitments during 2008-2012. Japan and Canada have made broad and macro plans to achieve the targets of such reductions. The European governments have passed on a part of emission reduction responsibility to the business entities in some identified sectors.

The European plan that is generally known as EU-ETS (European Union Emissions Trading Scheme) requires that the member countries allocate tradable emission rights to entities in identified sectors for the two phases- 2005-07 and 2008-12. These entities are required to provide compliance account each year by March in both the phases. Such compliance can be shown either by allowances or CERs.

Hence, the users of the CERs are (1) Entities in EU which compliance obligations under EU Allocation Scheme in 2005-07 and 2008-12, and (2) Governments of EU, Canada and Japan who have compliance obligations to account in 2008-12. In addition, a number of Traders, Funds and Bankers are also participants in the markets.

While the EU market is designed as preparation to comply with the KP, the legislation leading to such market has no limit like the KP commitment period (2008-12) and is more rigidly administrated.

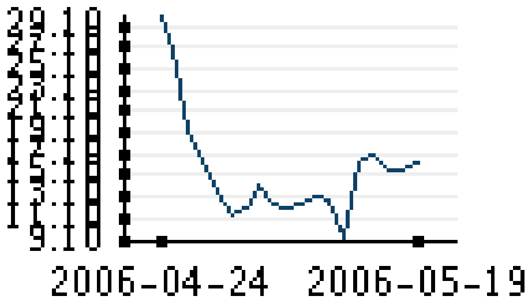
Accordingly, there are buyers in the market from EU countries, who have compliance requirements under EU-ETS NAP I 2005-07, are very active and paying higher prices. In contrast, the governments (EU, Japan, Canada) are motivated not so rigidly since there the compliance requirements are for KP commitment period in 2008-12, and are not so active in the market and are paying low prices for CERs.

Canada and Japan are also likely to come up similar regulations and trading schemes as in EU, which would make the market highly more active in coming years.

In addition, there are voluntary GHG emission reduction buyers from Australia and US that have not ratified the protocol.

Hence, the buyers of CERs from Indian CDM projects are (1) business entities that have direct compliance obligation (2005-07 and 2008-12) under EU regulations, (2) Governments that have compliance obligations (2008-12) under the KP, and (3) Traders/Funds/Banks buying on their behalf.

International prices of CERs are generally linked to European Union Allowance (EUA) prices, and the best CER prices, as per confidential market information from broking houses, is 80% of EUA. The trend in EUA prices in the recent past is captured below *(source: Point Carbon)*.



The differences in prices between EUA and CERs could be assigned to the following characteristics of theirs:

- EUA carry none of the project risks, country risks and Kyoto risks (or registration risk) that a CER will carry. EUA are issued by governments (like currency) and sellers in the EU have higher credit rating than most sellers of CERs and hence chances of non-delivery or default are less for EUA;
- delivery timing of CERs of current vintages up to 2007 is more uncertain because there could be delays in project implementation and persistent issues on additionality;
- validation of the ITL is not yet complete, and hence buyers of CERs need to be authorized by respective governments to use CERs for compliance to EU-ETS requirements and hold an account in the national registry that are yet emerging.

The World Bank has set certain benchmarks for adjusting prices of CERs based on project circumstances, indicated below:

Item	Adjustment (US$)	
	Minimum	Maximum
Project Risk	-2.00	+2.00
Delivery Guarantee	+2.00	+4.00
VER to CER: Registration	-1.00	-2.00
VER to CER: Issuance	-0.50	-1.00
Upfront Payment	-0.25	-0.50
Prices beyond 2012	-2.00	-4.00
Community Benefits	+0.25	+1.00
Technology or Regional Preference	+1.00	+2.00

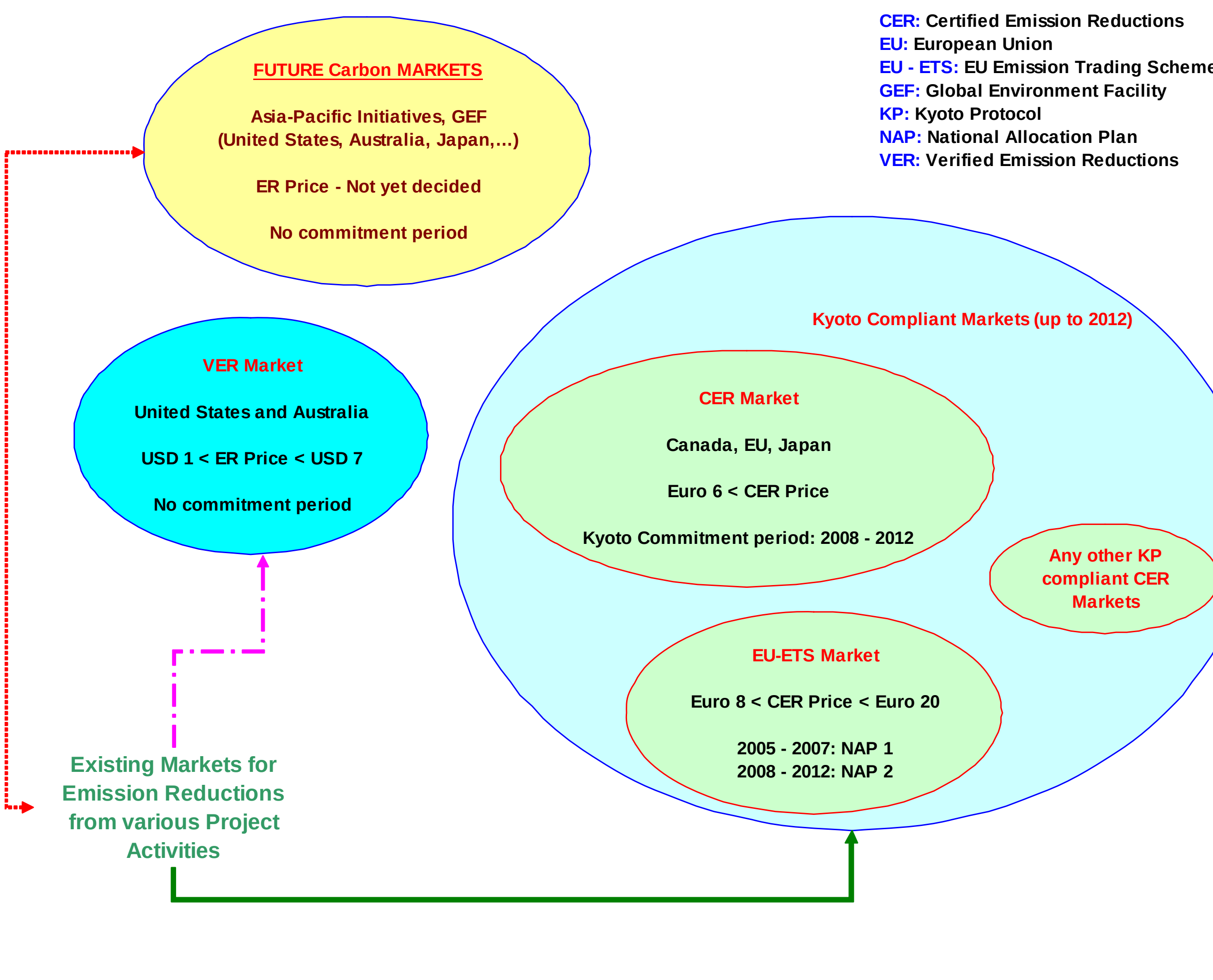
In addition to the CER markets driven by the KP and the EU-ETS, the following types of markets exist for emission reductions in decreasing order of price:

- KP driven market for CERs in Canada and Japan, that are not influenced by the current pressure of EU-ETS;
- VER (voluntary emission reductions) market in USA and Australia; and
- future carbon markets (like Asia-Pacific Initiatives, GEF, etc.).

A schematic of the overall current and future markets is included below.

In order to understand the potential CDM opportunities *(analysed under Chapter 4 in this report)* that exists for the Indian Oil Refining Sector, it is important to understand the profile of the sector *(discussed under Chapter 2 in this report)*, and processes and operations that are involved *(discussed under Chapter 3 in this report)* that would lead to direct and/or indirect emissions of GHGs targeted for reduction under the Kyoto Protocol.

In anticipation of potential CDM benefits, Indian corporations should develop inventories of GHGs, set internal targets for GHG emission reductions, understand the internal and external administrative requirements, and move forward to achieve the benefits *(discussed under Chapters 4, 5, 6 and 7 in this report)*.



2

Profile of Downstream Oil and Gas Sector

2.1 Sources of Natural Gas and Availability

According to a report prepared by PricewaterhouseCoopers Pvt. Ltd. (PwC) in January 2006 for India Brand Equity Foundation, the consumption of natural gas grew at a CAGR of 2.7% in the period 1999-2005 supported by rise in availability through domestic and imported sources of gas.

Liquefied Natural Gas (LNG) is being imported[12], and such import is permitted under the open general license category. Petronet LNG Limited (PLL), a joint venture promoted by Gas Authority of India Limited (GAIL), Indian Oil Corporation (IOC), Bharat Petroleum Corporation Limited (BPCL) and Oil & Natural Gas Corporation (ONGC), was formed for import of LNG to meet the growing demand in the country. Petronet LNG Limited constructed a 5 MMTPA LNG terminal at Dahej in Gujarat. The terminal capacity is being expanded to 10 MMTPA. Shell's 2.5 MMTPA capacity LNG Terminal at Hazira was commissioned in April 2005. Other LNG terminals under implementation/ consideration are at Dabhol, Kochi, Mangalore and Ennore. In June 2005, Sale Purchase Agreement (SPA) for import of 5 MMTPA of LNG from Iran was signed between GAIL/IOC/BPCL and National Iranian Gas Export Co. Ltd. (NIGEC) and imports are likely to start by the end of 2009.

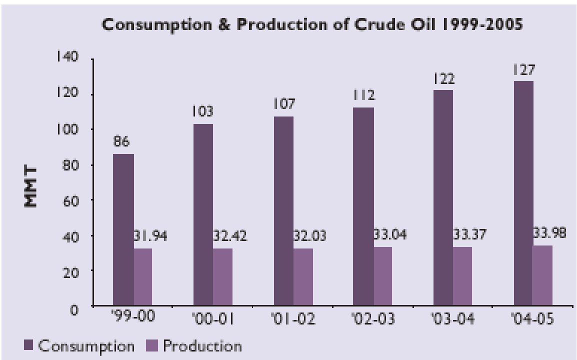
With potential availability of gas from domestic sources, particularly in Krishna-Godavari (KG) basin, additional production from Tapti, which is a joint venture field and imports of LNG by PLL at Dahej and Shell at Hazira, there is a need for commensurate increase in gas pipeline infrastructure. The existing natural gas pipeline length is 5,340 km; in addition, the recent gas discoveries are expected to lead to new pipeline infrastructure set-up. A gas pipeline policy, envisaging authorization from Government/ regulator for all gas transmission pipelines is being worked out. In such initiatives, if higher controls on fugitive emissions and leaks are exercised, then potential CDM projects could be developed.

2.2 Crude Oil Sources and Refining Trends

According to the PwC report referred earlier, India is sixth largest crude oil consumer in the world with consumption at 119.3 MMT in 2004, and is also ninth largest crude oil importer in the world. Also, we rank sixth in refining capacity in the world at 2.5 million barrels of oil per day in 2004 which is 3% of the world's refining capacity.

[12] Refer page # 145 – 147, of link # 3 under "Principle References and Links".

India sources about 75% of its requirement of crude petroleum through imports. The domestic production of crude oil has been in the range of 32-34 MMT over the past few years. About 60% of its crude imports are from the Middle East. The trend in consumption and production figures[13] for crude oil in India is depicted below.



The refining capacity[14] has increased from 118.37 MT per annum (MTPA) as on April 1, 2003 to 127.37 MTPA as on October 1, 2005.

As per data available from MoPNG, the pipeline infrastructure available in the country for transport of Crude Oil is 3,971 km with capacity of 36.18 MMTPA (Million Metric Tonnes Per Annum). This is about 30% of the total crude oil consumption, and leaves a scope for change from other modes of crude transportation to pipeline modes thereby reducing GHG emission levels.

As per the PwC report referred earlier, India has a total of 18 refineries with Indian Oil (Indian Oil Corporation Ltd.) currently owning the maximum refining capacity. Indian companies are expanding refinery capacity and putting up green-field refinery projects.

It is expected[15] that by 2007, the refining capacity of the country would increase from 127.4 MMTPA to 141.7 MMTPA. The Reliance Industries Limited (RIL) has ambitious plans for increasing refining capacity from 33 MMTPA to 60 MMTPA.

As per current plans, the crude oil pipeline infrastructure would increase by 4,065 km. In the pipeline mode of transportation, if any initiatives are planned to reduce the consumption of pumping energy, such initiatives could potentially qualify for CDM benefits.

In addition, if there are initiatives to switch from other modes of transportation, e.g., ocean tankers that consumes GHG emitting fuels, to cross-country pipeline mode of transportation, then there could be potential for availing CDM benefits.

2.3 Product Characterization

India continues to have a net exportable surplus in refined petroleum products. As per mid-term review of the 10th 5-year plan, the production of petroleum products for 2004-05 was 118.23 MMT with consumption being 111.56 MMT. As per findings of the PwC report, Petroleum, Oil Lubricants (PoL) exports comprises 8% of the total exports for 2004-05.

India has ambitions to become the hub for petroleum products exports. Demand for petroleum products in the Asia Pacific region is estimated to be

[13] Source: MoPNG.

[14] Refer page # 145 – 147, of link # 3 under "Principle References and Links".

[15] Source: Mid term year Review of Tenth Five Year Plan.

around 25 to 27 million barrels per day (1.2-1.3 billion tonnes per year) in the year 2010. China with a demand of around 9 million barrels per day (447 million tonnes per year) and Japan at 5.2 million barrels per day (260 million tonnes per year) are expected to dominate future demand for energy products. As per industry sources quoted in the PwC report, the refining capacity in the Asia Pacific region is expected to increase from the current 21.9 million barrels per day (1.09 billion tonnes per year) to a maximum of 25 million barrels per day in the year 2010. The export potential coupled with the additional capacity additions and new refineries provide a unique opportunity to potentially qualify for CDM benefits through use technologies and practices that are not common and/or are innovative to Indian situations.

Opportunities also exist for development of new and innovative products like bio-diesel that emit much less GHGs than conventional petroleum fuels. In October 2005, the MoPNG has announced a bio-diesel purchase policy which comes into effect from 1.1.2006. The policy prescribes that the National Oil Companies (NOCs) shall purchase bio-diesel of prescribed BIS (Bureau of Indian Standards) specification from registered authorized suppliers through 20 purchase centers at a uniform price of US$ .55 per liter. The purchase price would be reviewed by the oil companies every six months with due consideration to market conditions. Small and medium entrepreneurs would find opportunities in Jatropha cultivation and Bio-diesel conversion. Such initiatives could also qualify as potential CDM projects.

As the refining capacity increases, the quantity and range of products also increases. The PwC report mentioned earlier indicates that the product pipeline infrastructure would increase by 15,788 km. This also brings along opportunities to switch from other non-pipeline modes of product transport that emits GHGs to pipeline modes, thereby reducing such emissions, and qualify for CDM benefits.

2.4 Economic Trends

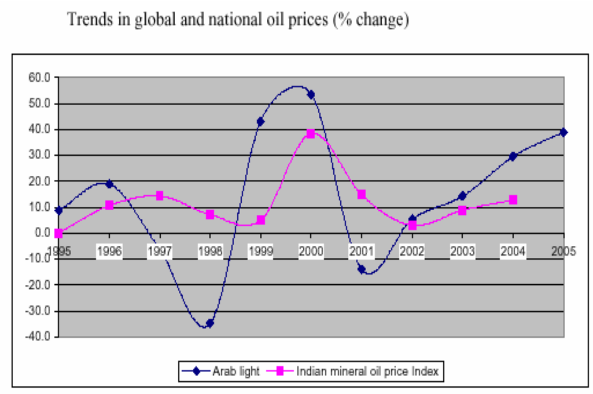
Historically the Indian economy has been shielded against any sharp spike in oil prices[16]. The Administered Price Mechanism (APM) in the oil sector ensured that the impact of any sharp increase in international oil prices were dissipated by spreading over the price increase through smaller incremental hikes spread over a period of time. The oil pool account even then ran substantial deficits, which was partially recharged when the international oil prices went into a trough phase. The APM has been dismantled in 2002, and such protection had been withdrawn.

The international oil prices are spiraling sharply and higher from late 2003 onwards, with considerable week-to-week and even day-to-day volatility. The fluctuations in oil prices as per the FICCI report are shown below.

The oil marketing companies (OMCs) in consultation with the Indian government moderated this price increase effect in essential products like petrol and diesel while maintaining the existing subsidies on domestic LPG and PDS kerosene. However, there have been huge under-recoveries in these measures, and it has been estimated that under-recoveries more than doubled from Rs. 9,274 crore in 2003-04 to Rs.20,146 crore in 2004-

[16] Impact of High Oil Prices on Indian Economy, a report by FICCI in May 2005.

05, and still continue to rise. In order to



compensate the public sector OMCs on account of their mounting under-recoveries, over and above the amount allowed as direct subsidy, additional Rs. 5,750 crore of 'oil bonds' were provided. Because of such difficult financial situations, some non-prevalent or technologically innovative projects jointly undertaken by the refiners and the OMCs, could qualify as CDM projects.

As a measure to minimize atmospheric emissions from vehicles, as laid down in the Auto Fuel Policy, Bharat Stage III petrol and diesel in identified cities, and Bharat Stage II petrol and diesel throughout the country have been introduced progressively with effect from April 1, 2006. It is proposed to introduce Bharat Stage III norms for petrol and diesel in the entire country and Euro IV in select cities from April 1, 2010, subject to a review in 2006. Any technology innovations in such activities which are prohibitive for implementation, where from economic considerations or newness of the technology compared to existing common ways of getting cleaner petrol, could qualify as CDM project.

In spite of volatile oil markets, there have been planned major investments in the refinery and retail expansion projects by companies in India *(as per Industry Sources: MoPNG)*, of about US$ 30 billion up to 2008. These include downstream projects by PSUs worth US$ 9.78 billion and those by Private Sectors worth US$ 4.89 billion. Based on the type of projects planned and if some of these could lead to GHG emission reductions whereas common and proven type of alternatives were available for implementation of such expansion projects, potential CDM benefits could be availed of by the investors.

Indian companies, may also like to acquire capacities at overseas downsteam operations in other NON-ANNEX I countries with lower efficiency levels. Any improvements projects undertaken in such acquisitions may also qualify for CDM benefits.

2.5 Legislations on Control of Air Emissions

Neither the Petroleum and Natural Gas Rules, 1959 (as amended by Rules, 2003) nor the Petroleum Rules, 2002, provide for any control of emissions during for downstream operations.

The following existing environmental regulations provide for emissions control for non-GHGs and do not cover the gases addressed under the KP.

- ✓ Air (Prevention and Control of Pollution) Act, 1981, as amended upto 1987/ and Rules, 1982

- ✓ The Environment (Protection) Act, 1986, amended 1991/ Amendment Rules, 2003.

Since, none of the GHG under KP is addressed for mitigation from oil downstream activities, there are significant opportunities to identify and implement GHG mitigation projects with CDM revenue in mind.

3

Footprint of Processes

3.1 Basics about processes on transmission and distribution of natural gas

Processed natural gas downstream of exploration activities is transported to customers end through a network of cross-country pipeline. The pipelines are provided with compressor stations, etc., equipped with accessory facilities. However, fugitive losses at compressor stations, through gate valves, etc, have remained under consideration at many places. Apart from fugitive emission, other indirect emissions can be linked to electricity requirements for natural gas transportation, pumping etc. Because of these issues, CDM potential could be considered for any improvement measures.

3.2 Basics about Crude Oil, Processing Complexities and GHG Emissions

Crude oil is a mixture of different hydrocarbons with small amounts of impurities. There could be significant variations in the composition depending on the source of crude oil. The complexity of operations used at a given refinery depends upon the properties of the crude oil to be refined and the desired products, and hence typically two refinery businesses may never alike. The variations in the operations could be in the form of outputs from some process are: (1) fed back into the same process or (2) fed to new processes or (3) fed back to a previous process or (4) blended with other outputs to form finished products. The typical major unit operations are briefly discussed in this chapter of the report. In addition to those processes listed in this chapter, there could also be many special purpose processes which may play an important role in a facility's efforts to comply with regulatory requirements on pollution control or requirements on product specification.

The combinations of physical, chemical and thermal processes at oil refineries convert crude oil (and also natural gas) into petroleum products as per market requirements. Most of these processes are typically energy-intensive, and result in emission of GHGs among others. The main GHGs emitted are carbon dioxide (CO_2) from process furnaces, boilers, gas turbines, fluidized catalytic cracking (FCC) regenerators, flare systems and tail gas incinerators. In addition, methane (CH_4) emissions could occur due to fugitive emissions, leakages from storage tanks and gas flaring systems. The emissions from various operations are indicated under this chapter of the report.

The refining operations for crude oil into useful petroleum products could be classified under two phases of activities and a number of supporting operations. The first phase involves desalting of crude oil and the subsequent distillation into its various hydrocarbon components called *'fractions'*. The second phase involves three different types of *'downstream processes'* (combining, breaking and reshaping) involving the fractions separated in the first phase. The downstream processes convert some of the distillation fractions into desired petroleum products such as residual fuel oil, gasoline, kerosene, etc., through combinations of different processes such as cracking, coking, reforming and alkylation.

The supporting operations include wastewater treatment, gas treatment and sulfur recovery, additive production, heat exchanger cleaning, blow down systems, blending of products and storage of products, power generation, water purification systems, etc.

In addition to the refinery operations mentioned above, there are associated processes related pre- and post- refining operations, like crude oil transportation and storage, and storage and transportation of products, whose boundaries could be extended outside refinery complexes.

3.3 Crude Oil Desalting and Distillation

Desalting. Prior to separation of crude oil into its several fractions through distillation, it usually must first be treated to remove corrosive salts. This cleaning operation is called *'desalting'* and it removes some of the metals and suspended solids which if present during fractionating operations, may cause catalyst deactivation. *'Desalting'* involves mixing of heated crude oil with water so that the salts are dissolved in the water. The emission that occur due to desalting process are Heater stack gas (CO, Sox, NOx, hydrocarbons and particulates), fugitive emissions (hydrocarbons).

Atmospheric Distillation. The desalted crude oil is heated in a heat exchanger train and furnace and fed to a vertical distillation column at atmospheric pressure where most of the feed is vaporized and separated into its various fractions by condensing on fractionation trays, each corresponding to a different condensation temperature. The lighter fractions condense and are collected towards the top of the column. Heavier fractions, which may not vaporize in the column, are further separated later by *vacuum distillation*. An important product produced in atmospheric distillation, as well as many other refinery processes, is the light, non-condensable refinery fuel gas (mainly methane and ethane). Typically this gas also contains hydrogen sulfide and ammonia. The mixture of these gases is known as "sour gas" or "acid gas". The sour gas is sent to the refinery sour gas treatment system which separates the fuel gas so that it can be used as fuel in the refinery heating furnaces. Air emissions during atmospheric distillation arise from the combustion of fuels in the furnaces to heat the crude oil, process vents and fugitive emissions.

Vacuum Distillation. Heavier fractions from the atmospheric distillation unit cannot be distilled without cracking under its pressure and temperature conditions. These are vacuum distilled at a very low pressure to increase volatilization and separation. The potential sources of emissions from vacuum distillation of crude oil are the combustion of fuels in the furnace and some light gases leaving the top of the condensers on the vacuum distillation column. A certain amount of non-condensable light hydrocarbons and hydrogen sulfide pass through the condenser to a hot well, and then are discharged to the refinery sour fuel system or are vented to a process heater flare or another control device to destroy hydrogen sulfide. The quantity of these emissions depends on the size of the unit, the type of feedstock, and the cooling water temperature.

3.4 Downstream Processing

Subsequent to the distillation processes, certain fractions are further refined through downstream processes like thermal cracking (vis-breaking), coking, catalytic cracking, catalytic hydro-cracking, hydro-treating, alkylation, isomerization, polymerization, catalytic reforming, solvent extraction, merox, de-waxing, propane de-asphalting and other operations. These downstream processes change the molecular structure of hydrocarbon molecules either by breaking them into smaller molecules or joining them to form larger molecules or reshaping them into higher quality molecules. For many of the operations, a number of different techniques are used in the industry; the major ones are described below.

Thermal Cracking. Thermal cracking (vis-breaking) uses heat and pressure to break large hydrocarbon molecules into smaller lighter molecules. The process has been largely replaced by catalytic cracking and most refineries may no longer employ thermal cracking. Air emissions from thermal cracking include emissions from the combustion of fuels in the process heater, vents and fugitive emissions.

Catalytic Cracking. This process uses heat, pressure and a catalyst[17] to break larger hydrocarbon molecules into smaller lighter molecules. Catalytic cracking has largely replaced thermal cracking, mentioned earlier, because it is able to produce more gasoline with a higher octane and less heavy fuel oils and light gases. Feed stocks are light and heavy oils from the crude oil distillation unit which are processed primarily into gasoline as well as some fuel oil and light gases. The catalytic cracking processes, as well as most other refinery catalytic processes, produce coke which collects on the catalyst surface and diminishes its catalytic properties. Fluidized-bed catalytic cracking units (FCCUs) are by far the most common catalytic cracking units. In this process, oil and oil vapor are pre-heated and contacted with hot catalyst either in the reactor itself or in the feed line (riser) to the reactor. The cracked oil vapors are fed to a fractionation tower where the various desired fractions are separated and collected. The catalyst is regenerated in a continuous process where deposits of coke on the catalyst are burned off. Some units also use steam to strip remaining hydrocarbons and oxygen from the catalyst before being fed back to the oil stream. Catalytic cracking is one of the most significant sources of air pollutants at refineries. Air emissions from catalytic cracking operations include: the process heater flue gas emissions, fugitive emissions and emissions generated during regeneration of the catalyst. Relatively high concentrations of carbon monoxide (CO) can be produced during regeneration of the catalyst which is typically converted to carbon dioxide (CO_2) either in the regenerator or further downstream in a CO waste heat boiler. In addition, a significant amount of fine catalyst dust is produced in FCCUs as a result of the constant movement of the catalyst grains against each other. Much of this dust, consisting primarily of alumina and relatively small amounts of nickel, is carried with the carbon monoxide stream to the carbon monoxide burner. The catalyst dust is then separated from the resulting carbon dioxide stream via cyclones and/or electrostatic precipitators and is sent off-site for disposal or treatment.

[17] The catalysts used here are multi-functional and are more widely used since they result in higher product yield, better product selectivity, reduced air emissions and longer catalyst life.

Coking. This is a cracking process used primarily to produce high-value blending components for transportation fuels, such as gasoline and diesel. This process also produces petroleum coke, which is essentially solid carbon with varying amounts of impurities, and is used as a fuel for power plants if the sulfur content is low enough and in non-fuel applications as a raw material for many carbon and graphite products including anodes for the production of aluminum and furnace electrodes for the production of elemental phosphorus, titanium dioxide, calcium carbide and silicon carbide. A number of different processes are used to produce coke: 'delayed coking' and 'fluid coking'. Hot vapors from the coke drums, containing cracked lighter hydrocarbon products, hydrogen sulfide and ammonia are fed back to the fractionator where they can be treated in the sour gas treatment system or drawn off as intermediate products. Steam is then injected into the full coke drum to remove hydrocarbon vapors, water is injected to cool the coke and the coke is removed. Typically, high pressure water jets are used to cut the coke from the drum. The injected steam is condensed and the remaining vapors are typically flared. The removal of coke from the drum can release particulate emissions and any remaining hydrocarbons to the atmosphere. Air emissions from coking operations include the process heater flue gas emissions, fugitive emissions and emissions that may arise from the removal of the coke from the coke drum.

Catalytic Hydrocracking. Catalytic hydrocracking normally utilizes a fixed-bed catalytic cracking reactor with cracking occurring under substantial pressure in the presence of hydrogen. Feedstocks to hydrocracking units are often those fractions that are the most difficult to crack and cannot be cracked effectively in catalytic cracking units. These include: middle distillates, cycle oils, residual fuel oils and reduced crudes. The hydrogen suppresses the formation of heavy residual material and increases the yield of gasoline by reacting with the cracked products. However, this process also breaks the heavy sulfur and nitrogen bearing hydrocarbons and releases these impurities to where they could potentially foul the catalyst. For this reason, the feedstock is often first hydrotreated to remove impurities (hydrogen sulfide and ammonia) before being sent to the catalytic hydrocracker. Sour gas and sour water streams are produced at the fractionator, however, if the hydrocracking feedstocks are first hydrotreated to remove impurities, both streams will contain relatively low levels of hydrogen sulfide and ammonia. Hydrocracking catalysts are typically regenerated off-site after two to four years of operation. Therefore, little or no emissions are generated from the regeneration processes. Air emissions arise from the process heater, vents, and fugitive emissions.

Hydrotreating/ Hydroprocessing. These are similar processes used to remove impurities such as sulfur, nitrogen, oxygen, halides and trace metal impurities that may deactivate process catalysts. Both hydrotreating and hydroprocessing units are usually placed upstream of those processes in which sulfur and nitrogen could have adverse effects on the catalyst, such as catalytic reforming and hydrocracking units. In addition to the treated products, the process produces a stream of light fuel gases, hydrogen sulfide and ammonia. The treated product and hydrogen-rich gas are cooled after they leave the reactor before being separated. The hydrogen is recycled to the reactor. The off-gas stream may be very rich in hydrogen sulfide and light fuel gas. The fuel gas and hydrogen sulfide are typically sent to the sour gas treatment unit and sulfur recovery unit. Air emissions from hydrotreating may arise from process heater flue gas, vents and fugitive emissions.

Alkylation. Alkylation is used to produce a high octane gasoline blending stock from the olefines formed primarily during catalytic cracking and coking operations, but also from catalytic reforming, crude distillation and natural gas processing. Alkylation joins an olefin and an isoparaffin compound using either a sulfuric acid or hydrofluoric acid catalyst. The products are alkylates including propane and butane liquids. Air emissions from the alkylation process may arise from process vents and fugitive emissions.

Isomerization. This is used to alter the arrangement of a molecule without adding or removing anything from the original molecule. Typically, paraffins (butane or pentane from the crude distillation unit) are converted to isoparaffins having a much higher octane. Isomerization processes require an atmosphere of hydrogen to minimize coke deposits; however, the consumption of hydrogen is negligible. Air emissions may arise from the process heater, vents and fugitive emissions.

Polymerization. This process is occasionally used to convert propene and olefines to high octane gasoline blending components, and is similar to alkylation in its feed and products, but is often used as a less expensive alternative to alkylation. The reactions typically take place under high pressure in the presence of a phosphoric acid catalyst. The feed must be free of sulfur, which poisons the catalyst basic materials, which neutralize the catalyst, and oxygen, which affects the reactions. Air emissions of sulfur dioxide may arise during the caustic washing operation.

Catalytic Reforming. Catalytic reforming uses catalytic reactions to process primarily low octane heavy straight run (from the crude distillation unit) gasoline and naphtha into high octane aromatics (including benzene). There are four major types of reactions which occur during reforming processes: (1) dehydrogenation of naphthenes to aromatics; (2) dehydrocyclization of paraffins to aromatics; (3) isomerization; and (4) hydrocracking. The dehydrogenation reactions are very endothermic, requiring that the hydrocarbon stream be heated between each catalyst bed. All but the hydrocracking reaction release hydrogen which can be used in the hydrotreating or hydrocracking processes. Air emissions from catalytic reforming arise from the process heater gas and fugitive emissions.

Solvent Extraction. Solvent extraction uses solvents to dissolve and remove aromatics from lube oil feed stocks, improving viscosity, oxidation resistance, color and gum formation. A number of different solvents are used with the two most common being furfural and phenol. The stream extracted from the solvent will likely contain high concentrations of hydrogen sulfide, aromatics, naphthenes and other hydrocarbons, and is often fed to the hydrocracking unit.

Chemical Treating. In petroleum refining, chemical treating is used to remove or change the undesirable properties associated with sulfur, nitrogen or oxygen compound contaminates in petroleum products.

Chemical treating is accomplished by either extraction (e.g., Merox process) or oxidation (also known as sweetening), depending upon the product. Extraction is used to remove sulfur from the very light petroleum fractions, such as propane/ propylene (PP) and butane/ butylenes (BB). Air emissions arise from fugitive hydrocarbons and the process vents on the separator which may contain disulfides.

Dewaxing. Lubricating oil base stocks are dewaxed to ensure that the oil will have the proper viscosity at lower ambient temperatures. Two types of dewaxing processes are used: selective hydrocracking and solvent dewaxing (more prevalent). In solvent dewaxing, the oil feed is diluted with solvent to lower the viscosity, chilled until the wax is crystallized, and then filtered to remove the wax. Solvents used for the process include propane and mixtures of methyl ethyl ketone (MEK) with methyl isobutyl ketone (MIBK) or MEK with toluene. Air emissions may arise from fugitive emissions of the solvents.

Propane Deasphalting. This produces lubricating oil base stocks by extracting asphaltenes and resins from the residuals of the vacuum distillation unit. Propane is usually used to remove asphaltenes due to its unique solvent properties. This process is similar to solvent extraction in that a packed or baffled extraction tower or rotating disc contactor is used to mix the oil feed stocks with the solvent. Air emissions may arise from fugitive propane emissions and process vents.

3.5 Supporting Services

There are important supporting operations and utilities which are not directly involved in the production of various hydrocarbon products. Of such supporting services, those likely to release emissions are discussed below.

Wastewater Treatment. Relatively large volumes of water are used by the petroleum refining industry. Four types of wastewater are produced: surface water runoff, cooling water, process water and sanitary wastewater. A large portion of water used in petroleum refining is used for cooling. Water used in processing operations also accounts for a significant portion of the total wastewater. Petroleum refineries typically utilize primary and secondary wastewater treatment. Some refineries employ an additional stage of wastewater treatment called polishing to meet discharge limits. Wastewater treatment plants are a significant source of refinery air emissions. Air releases arise from fugitive emissions from the numerous tanks, ponds and sewer system drains.

Blowdown System. Most refinery process units and equipment are manifolded into a collection unit, called the blowdown system. These systems provide for the safe handling and disposal of liquid and gases that are either automatically vented from the process units through pressure relief valves, or that are manually drawn from units. A series of flash drums and condensers are utilized to separate the blowdown into its vapor and liquid components. The gaseous component typically contains hydrocarbons, hydrogen sulfide, ammonia, mercaptans, solvents and other constituents, and is either discharged directly to the atmosphere or is combusted in a flare. The major air emissions from blowdown systems are hydrocarbons in the case of direct discharge to the atmosphere and sulfur oxides when flared.

Blending. Blending is the final operation in petroleum refining. It consists of mixing the products in various proportions to meet specifications such as vapor pressure, specific gravity, sulfur content, viscosity, octane number, cetane index, initial boiling point and pour point. Air emissions from blending are fugitive VOCs from blending tanks, valves, pumps and mixing operations.

3.6 Emissions from Crude Oil and Products

Storage tanks are used throughout the refining process to store crude oil and intermediate process feeds for cooling and further processing. Finished petroleum products are also kept in storage tanks before transport off site. Considerable emissions of volatile organic compounds (VOC) occur from storage tanks, particularly through tank seals.

4

Potential CDM opportunities available in Downstream Oil and Gas sector

4.1 Sources of GHGs and Potential CDM Opportunities

Different GHGs are emitted in the downstream oil and gas sector, including CO_2 and CH_4. The main sources of CO_2 emissions are in refining and product transportation operations such as in process furnaces, boilers, gas turbines, fluidized catalytic cracking regenerators, flare systems, tail gas incinerators, and electricity and steam generation. Methane is emitted along with other VOCs volatile hydrocarbons through fugitive emissions along gas pipeline route (including compressor stations) and during extraction processes, from refining equipment, storage tanks, and gas flaring systems.

Thus, there are tremendous opportunities in this sector to reduce GHG emissions, such as in:

(1) Fugitive emission reduction measures during natural gas transmission and distribution operations, such as at:

- pipelines including joints, gate valves and pipeline intersections, and
- at intermediate compressor stations, including during maintenance activities.

(2) energy efficiency measures like:

- optimization of process energy input,
- recovery of waste heat,
- cogeneration of heat and power, and
- use of refinery gases and flare gases as sources of heat;

(3) process improvements measures to:

- increase process efficiency, and
- optimize production processes;

(4) better management practices for different products:

- storage and transportation including where possible switching from a more GHG emission mode of transportation to a lesser GHG intensive mode of product transportation, and
- improvement in product storage facilities such as tank seals to prevent emission leakages of products;

(5) reducing fugitive methane emissions from various sources and also recovering methane as a useful energy source; and

(6) switch from solid or liquid fuels to gaseous fuels for power and/or steam generation.

The typical operations and associated emissions are discussed under Chapter

3 in this report; some potential opportunities have also been discussed under Chapter 2.

A list of such potential CDM opportunities that exist in the downstream oil and gas sector is included below.

List of Potential CDM Project Opportunities		
Sr. No.	**Activity/ Process/ Operation**	**Nature of Activities generating potential CDM project opportunities**
1.	Natural gas transmission and distribution	(1) Improvement in leak detection system resulting in better monitoring of fugitive emissions and leakage controls. (2) Improved maintenance of pipeline and components at compressor stations, thereby reducing leakages and venting. (3) In case of long cross-country pipelines, power required for pipeline operations may be generated with natural gas instead of using available grid power, thereby reducing net GHG emissions associated with power generation.
2.	Crude Oil Transportation and Product Storage, transportation and distribution	(1) Change in mode of transportation to pipeline mode where practicable, thereby avoiding GHG emissions associated with any non-pipeline mode of transportation.
3.	Crude oil Desalting	(1) Use of CO present in heater stack gases as source of energy replacing any conventional GHG emissive fuel.
4.	Atmospheric and Vacuum Distillation	(1) Use of CO present in heater stack gases as source of energy replacing any conventional GHG emissive fuel. (2) Process modifications resulting in GHG emission reductions. (3) Reduction in fugitive emissions and recovery of methane content.

List of Potential CDM Project Opportunities

Sr. No.	Activity/ Process/ Operation	Nature of Activities generating potential CDM project opportunities
5.	Thermal Cracking	(1) Use of CO present in heater stack gases as source of energy replacing any conventional GHG emissive fuel. (2) Process modifications resulting in GHG emission reductions. (3) Use of a lesser GHG emissive fuel as source of heat energy.
6.	Coking	(1) Use of CO present in heater stack gases as source of energy replacing any conventional GHG emissive fuel. (2) Process modifications resulting in GHG emission reductions. (3) Reduction in fugitive emissions and recovery of methane content. (4) Steam use optimization.
7.	Catalytic Cracking, Catalytic Hydro-Cracking, Hydro-treating/ Hydroprocessing, Catalytic Reforming	(1) Use of better yielding catalysts. (2) Use of CO present in heater stack gases as source of energy replacing any conventional GHG emissive fuel. (3) Process modifications resulting in GHG emission reductions. (4) Reduction in fugitive emissions and recovery of methane content. (5) Use of a lesser GHG emissive fuel as source of heat energy.

List of Potential CDM Project Opportunities		
Sr. No.	**Activity/ Process/ Operation**	**Nature of Activities generating potential CDM project opportunities**
8.	Alkylation, Isomerization, Propane Deasphalting	(1) Use of CO present in heater stack gases as source of energy replacing any conventional GHG emissive fuel. (2) Process modifications resulting in GHG emission reductions. (3) Reduction in fugitive emissions and recovery of methane content. (4) Use of a lesser GHG emissive fuel as source of heat energy.
9.	Solvent Extractive, Merox Treating, Blending, Heat Exchanger Cleaning, Product Storage Tanks, Wastewater Treatment System	(1) Reduction in fugitive emissions and recovery of methane content. (2) Process modifications resulting in GHG emission reductions.
10.	Blow down and Flare	(1) Waste heat and flare gas recovery. (2) Reduction in fugitive emissions and recovery of methane content.
11.	Steam Generation and Usage	(1) Use of a lesser GHG emissive fuel as source of heat energy. (2) Improvement of faulty steam traps and/or replacement with more efficient steam traps.
12.	Electricity usage	(1) Use of more efficient electrical equipment.
13.	Any other	(1) Heat integration processes, such as use of Pinch Technology. (2) Utilization of excess over-designed capacities for flare gas, steam etc., in innovative ways.

List of Potential CDM Project Opportunities		
Sr. No.	**Activity/ Process/ Operation**	**Nature of Activities generating potential CDM project opportunities**
		(3) Use of renewable energy sources for power generation. (4) Utilization of process wastes as by-products.

4.2 Development of Opportunities on CDM projects

The identified potential activities with CDM potential could be structured for registration by the CDM EB provided they satisfy the eligibility criteria and applicability criteria as per available approved CDM methodology. A list of approved methodologies that the downstream oil and gas sector may utilize (in current form or with revisions), if applicable to the type of CDM initiatives developed, is provided below.

1. ACM0002: "Consolidated baseline methodology for grid-connected electricity generation from renewable sources";
2. ACM0004: "Consolidated baseline methodology for waste gas and/or heat and/or pressure for power generation";
3. ACM0007: "Baseline methodology for conversion from single cycle to combined cycle power generation";
4. ACM0009: "Consolidated baseline methodology for industrial fuel switching from coal or petroleum fuel to natural gas";
5. AM0008: "Industrial fuel switching from coal and petroleum fuels to natural gas without extension of capacity and lifetime of the facility";
6. AM0009: "Recovery and utilization of gas from oil wells that would otherwise be flared";
7. AM0013: "Avoided methane emissions from organic waste-water treatment";
8. AM0014: "Natural gas-based package cogeneration";
9. AM0017: "Steam system efficiency improvements by replacing steam traps and returning condensate";
10. AM0018: "Baseline methodology for steam optimization systems";
11. AM0019: "Renewable energy projects replacing part of the electricity production of one single fossil fuel fired power plant that stands alone or supplies to a grid, excluding biomass projects";
12. AM0022: "Avoided Wastewater and On-site Energy Use Emissions in the Industrial Sector";
13. AM0023: "Leak reduction from natural gas pipeline compressor or gate stations";
14. AM0027: "Substitution of CO2 from fossil or mineral origin by CO2 from

renewable sources in the production of inorganic compounds";

15. AM0029: "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas";
16. II. B.: Supply side energy efficiency improvements – generation;
17. II.C.: Demand-side energy efficiency programmes for specific technologies;
18. II.D.: Energy efficiency and fuel switching measures for industrial facilities;
19. III. B.: Switching fossil fuels;
20. III. D.: Methane recovery.

4.3 Determining Baseline Emissions

The baseline for a CDM project activity is the scenario that reasonably represents the anthropogenic emissions by sources of GHG that would occur in the absence of the proposed project activity. A baseline shall cover emissions from all gases, sectors and source categories listed in Annex A of KP within the project boundary. A baseline shall be deemed to reasonably represent the anthropogenic emissions by sources that would occur in the absence of the proposed project activity if it is derived using a baseline methodology referred to in paragraphs 37 and 38 of the CDM modalities and procedures.

The application of any CDM methodology calls for identifying and establishing a baseline scenario among viable alternatives to the CDM project and estimating the likely baseline emissions. The applicable CDM methodology provides guidelines on baseline determination and estimation of associated emissions.

In some instances, national level baselines may be available as per information provided by the NATCOM (the official nodal agency within the MoEF for calculating sectoral emission levels for India and communicating the same to the UNFCCC). In other cases, based on baseline practices and similar practices available in the sector that is similar to the project activity, project-specific baselines could be determined.

5

Broad assessment of CDM potential for Downstream Oil & Gas sector

5.1 CDM opportunities in Operations and Utilities

The different types of CDM opportunities available to the Indian Refining sector and available CDM methodologies for structuring such opportunities for CDM registration are provided under Chapter 4. It should be noted here that such opportunities would vary in nature, scale and location, since as explained under section 3.1, no two refinery businesses can be similar to each other. The potential opportunities would also differ on the basis of what is the existing technology used in a process, its efficiency and costs, age or vintage of the technology in use, and if a better one can be utilized to retrofit the existing or replace it. Such considerations are important in the assessment of any potential opportunities since different refinery businesses in India came up at different periods in time during the past decades, and each had used the prevailing (best) available technology measure. Many of the businesses even went for modernizations and expansions, and further technology modifications were undertaken.

The assessment of opportunities should also be seen on the background of CDM eligibility criteria, and whether these opportunities are actually ‘business as usual’ scenarios which would have occurred anyway irrespective of the projects barriers and hurdles.

Based on the above considerations, it is highly unlikely that any refinery business will bring forward a CDM project of similar scale as any other business operation in the sector. However, similar types of opportunities do exist, and have been described under section 5.2 below.

5.2 CER Potential in the downstream Oil and Gas sector

Based on data published by the MoPNG and the IPCC, sector level CDM potentials have been estimated separately for (1) natural gas transmission and distribution and (2) crude oil refining, storage and associated activities.

While estimating the CER potential through the carbon balance approach, it is assumed that the quantity of carbon wasted as emissions, effluents and other wastes including solids, due to residual calorific value could be utilized through some initiatives resulting in avoidance of GHG emissive fuels and/or materials somewhere else. Thus, these estimates represent the maximum achievable theoretical potentials in the sector. However, how much of such potential is practicably achievable within acceptable marginal costs for CER generation has not been gone into. It is also to be noted that is undertaken for mandatory pollution control/ abatement requirements necessarily will not be eligible for CDM process. The typical projects that would qualify from this sector would involve direct and/or indirect reduction in emissions of CO_2, CH_4 and N_2O.

For pipeline transportation of natural gas the estimated CO_{2eq} emissions from methane during natural gas transportation in 2004-05 was 1,782,000 tonnes, and is expected to grow at an annual average rate of 1.92%. This is the average CDM potential for natural gas transmission and distribution.

Similar estimations completed for refinery operations, crude and product handling, storage and transportation, indicate that estimated total equivalent CO_2 emissions from carbon losses (between crude oil and products) during 2004-05 was 28,567,000 tonnes of which 89,500 tonnes was CO_2 equivalent of methane emissions from refining operations and storage tanks (representing CDM potential). These potentials are expected to grow at an annual average rate of 5.3%.

The anticipated CER revenue will depend on the prevailing market prices for CERs.

The CER revenue potential estimates are provided under Tables 1 through 4.

Table 1: Crude Oil Consumption during 2004 - 2005

Sr. No.	Refinery	Public/ Private Sector	Total Crude Oil throughput during 2004-05 ('000 Tonne)	Carbon in Crude (%)	Quantity of Carbon in Crude ('000 Tonne)
1	IOC, Guwahati, Assam	Public	1002	85	851.7
2	IOC, Barauni, Bihar	Public	5082	85	4319.7
3	IOC, Koyali, Gujarat	Public	11698	85	9943.3
4	IOC, Haldia, WB	Public	5418	85	4605.3
5	IOC, Mathura, UP	Public	6387	85	5428.95
6	IOC, Digboi, Assam	Public	651	85	553.35
7	IOC, Panipat, Haryana	Public	6387	85	5428.95
8	BPCL, Mumbai, MH	Public	9138	85	7767.3
9	HPCL, Mumbai, MH	Public	6118	85	5200.3
10	HPCL, Vizag, AP	Public	7825	85	6651.25
11	KRL, Kochi, Kerala	Public	7924	85	6735.4
12	CPCL, Manali, TN	Public	8181	85	6953.85
13	CPCL, Narimanam, TN	Public	742	85	630.7
14	BRPL, Bongaigaon, Assam	Public	2311	85	1964.35
15	NRL, Numaligarh, Assam	Public	2042	85	1735.7
16	ONGC, Tatipaka, TN	Public	93	85	79.05
17	MRPL, Mangalore, Karnataka	Public	11809	85	10037.65
18	RPL, Jamnagar, Gujarat	Private	34309	85	29162.65
	Total Crude Oil Throughput =		**127,117**		**108,049**

Table 2: Refinery Product Generation during 2004 - 2005

Sr. No.	Name of Product	Nature of Product	Product Quantity during 2004-05 (MT)	Carbon in Product (%)	Quantity of Carbon in Product (MT)
1	LPG	Light Distillates	5569	82	4566.58
2	Mogas	Light Distillates	11017	82	9033.94
3	Naphtha	Light Distillates	14315	85	12167.75
4	Others Light Distillates	Light Distillates *(considered as liquid)*	1800	85	1530
5	Kerosene	Middle Distillates	9300	85	7905
6	ATF/ RTF/ Jet A-1	Middle Distillates	5201	85	4420.85
7	HSD	Middle Distillates	45880	85	38998
8	LDO	Middle Distillates	1546	85	1314.1
9	Other Middle Distillates	Middle Distillates *(considered as liquid)*	538	85	457.3
10	Furnace Oil	Heavy Ends	10519	85	8941.15
11	LSHS/ HHS/ RFO	Heavy Ends	4261	85	3621.85
12	Lube Oils	Heavy Ends	646	85	549.1
13	Bitumen	Heavy Ends	3349	83.5	2796.415
14	Petroleum Coke	Heavy Ends	3158	92.3	2914.834
15	Paraffin Wax	Heavy Ends	66	85.23	56.2518
16	Other Waxes	Heavy Ends	8	85.23	6.8184
17	Other Heavy Ends	Heavy Ends *(considered as solid)*	1060	92.3	978.38
	Total product quantities =		**118,233**		**100,258**

Table 3: CO_2 and CH_4 emissions due to use of Crude Oil during 2004 - 2005

Sr. No.	Parameters	Unit	Quantity
1	Quantity of Carbon in Crude	1,000 T	108049
2	Quantity of Carbon in Product	1,000 T	100258
3	Quantity of Carbon wasted as Emissions, Effluents and Other Wastes including Solids	1,000 T	7791
4	Carbon Loss w.r.t Crude Oil	%	7.2
5	Total equivalent CO_2 emissions from carbon losses	1,000 T/year	28567
6	Methane emission factor for crude oil refining (90 - 1400)	kg/PJ	745
7	Methane emission factor for crude oil storage in tanks (20 - 250)	kg/PJ	135

Table 3: CO_2 and CH_4 emissions due to use of Crude Oil during 2004 - 2005

Sr. No.	Parameters	Unit	Quantity
8	Total methane emission factor from crude oil refining and tank storages	kg/PJ	880
9	Net Calorific Value of crude oil (refinery feedstock)	TJ/10^3 tonnes	44.8
10	Total methane emissions from crude oil refining and tank storages	1,000 T	4.3
11	Global Warming Potential for methane	--	21
12	**$CO_{2equivalent}$ of methane emissions from crude oil refining and tank storages**	**1,000 T**	**89.5**
13	Crude oil consumption during 2000-01	1,000 T	103444
14	Crude oil consumption during 2001-02	1,000 T	107274
15	Crude oil consumption during 2002-03	1,000 T	112559
16	Crude oil consumption during 2003-04	1,000 T	121840
17	Crude oil consumption during 2004-05	1,000 T	127117
18	Increase in Crude Oil consumption from 2001 - 02	%	3.70
19	Increase in Crude Oil consumption from 2002 - 03	%	4.93
20	Increase in Crude Oil consumption from 2003 - 04	%	8.25
21	Increase in Crude Oil consumption from 2003 - 04	%	4.33
22	Average increase in Crude Oil consumption from 2000 - 05	%	5.30
23	**Forecasted annual average growth in CO_2 emissions for use of crude oil in refineries**	**1,000 T**	**1514**
24	**Forecasted annual average growth in $CO_{2equivalent}$ of methane emissions from crude oil refining and storage tanks**	**1,000 T**	**5**

Table 4: CH_4 emissions due to Transmission & Distribution of Natural Gas

Sr. No.	Parameters	Unit	Quantity
1	Natural Gas production from onshore facilities of OIL, ONGC and JVC/Private during 2004-05	10^6 SCM	8977
2	Natural Gas production from offshore facilities of ONGC (Mumbai High) and JVC/Private during 2004-05	10^6 SCM	22800
3	Total Natural Gas production from onshore and offshore facilities during 2004-05	10^6 SCM	31777
4	Average density of Natural Gas	kg/SCM	0.47
5	Quantity of natural gas produced *(assumed to be also consumed)* during 2004-05	10^6 kg	14935
6	Methane emission factor during transmission and distribution of Natural Gas consumed	kg/PJ	118000
7	Net Calorific Value of Natural Gas *(assumed same as Refinery Gas)*	TJ/10^3 tonnes	48.15

Table 4: CH_4 emissions due to Transmission & Distribution of Natural Gas

Sr. No.	Parameters	Unit	Quantity
8	Total methane emissions from crude oil refining and tank storages	1,000 T	84.9
9	Global Warming Potential for methane	--	21
10	**$CO_{2equivalent}$ of methane emissions from crude oil refining and tank storages**	**1,000 T**	**1782.0**
11	Natural Gas production during 2000-01	10^6 SCM	29477
12	Natural Gas production during 2001-02	10^6 SCM	29714
13	Natural Gas production during 2002-03	10^6 SCM	31389
14	Natural Gas production during 2003-04	10^6 SCM	31962
15	Natural Gas production during 2004-05	10^6 SCM	31777
16	Increase in Natural Gas production (consumption) from 2001 - 02	%	0.80
17	Increase in Natural Gas production (consumption) from 2002 - 03	%	5.64
18	Increase in Natural Gas production (consumption) from 2003 - 04	%	1.83
19	Increase in Natural Gas production (consumption) from 2003 - 04	%	-0.58
20	Average increase in Natural Gas production (consumption) from 2000 - 05	%	1.92
21	**Forecasted annual average growth in $CO_{2equivalent}$ of methane emissions from Natural Gas transmission and distribution**	**1,000 T**	**34**

From the details provided above, it appears that in 2004-05, the maximum carbon lost in the Indian refining processes by way of emissions, effluents and other wastes, amounted to about 29 million tonnes of CO_2. The primary loss is expected to be through emissions and not through effluents and other wastes.

The emissions cannot be eliminated but replaced with some other cleaner energy options, the potential for which is again expected to be minimal and limited. In a refinery set-up, most emissions could be linked to operations of some furnaces that generally operate at 85% efficiency; such efficiency could be improved to 92% by implementing projects on energy efficiency/ equipment replacement/ upgradation, etc. This could lead to 7% (=92% - 85%) reduction in emissions which is approximately 2 million CERs per year. This is a maximum practicable CER potential in the refining sector.

6

Administrative process requirements for obtaining CDM revenues

6.1 Overview of CDM Eligibility of Potential Projects

The internal and external administrative process requirements must be in line with the eligibility requirements for any potential CDM project. Hence, the CDM eligibility criteria are discussed here. Such eligibility criteria are primarily based on the *"Tool for the demonstration and assessment of additionality – approved by the CDM Executive Board*[18] *(CDM EB)"* and also on available set of approved CDM methodologies for specific project types. Where approved methodologies are absent for any specific type of project, new methodologies can be proposed and approval obtained from the CDM EB. The six eligibility steps are discussed below, followed by a discussion on the CDM Project Cycle.

While deciding on the CDM eligibility of a project, a check needs to be run through step 0 to step 5 as discussed below. In case, any of these steps is not satisfied, then the project under consideration will not be an eligible CDM project.

Step 0: Preliminary Screening based on Starting Date of Project Activity

Any potential opportunity, called 'project activity', must have started after 1 January 2000. The *start date* of a project activity could be beginning date *implementation* or *construction* or *real action*. While deciding on the starting date, the project participant (proponent or developer) must provide evidence that the incentive from the CDM was seriously considered in the decision to proceed with the project activity. This evidence shall be based on (preferably official, legal and/or other corporate) documentation that was available at, or prior to, the start of the project activity. This could include evidence of the objective to mitigate climate change.

If step 0 is satisfied, then step 1 of the eligibility assessment should be analyzed.

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

This include identification of realistic and credible alternative(s) available to project proponent that would provide outputs or services comparable with the proposed CDM project activity, and are in compliance with all applicable legal and regulatory requirements, even if these laws and regulations have objectives other than GHG reductions.

If step 1 is satisfied, then either step 2 of the eligibility assessment or step 3 or both should be analyzed.

[18] Refer link # 1 under "Principle References and Links".

Step 2: Investment Analysis

This step includes analysis to demonstrate whether the proposed CDM project activity is (was) economically or financially less attractive than other alternatives identified under *step 1* without considering the revenue from potential sale of certified emission reductions (CERs) arising from that project activity.

The investment analysis may include indicators such as IRR, NPV, unit cost of output, etc., and processes of benchmarking and sensitivity analysis should be applied as appropriate.

<u>If step 2 is satisfied, then either step 3 of the eligibility assessment or step 4 should be analyzed.</u>

Step 3: Barrier Analysis

Under this step it needs to be demonstrated that the proposed CDM project activity faces (faced) barriers that would:

(a) prevent the implementation of this type of proposed project activity; and

(b) not prevent the implementation of at least one of the alternatives identified under *step 1*.

One or more of the following types of barriers need to be demonstrated:

- **Investment barriers**, other than the economic/ financial barriers *in step 2;*
- **Technological barriers**, *inter alia*:
  - skilled and/or properly trained labour to operate and maintain the technology is (was) not available and no locally available education/ training institution in India provides the needed skill, leading to equipment disrepair and malfunctioning; and
  - there is (was) lack of infrastructure for implementation of the technology used in the project activity.
- **Barriers due to prevailing practice**, *inter alia*:
  - the project activity is (was) the "first of its kind", meaning, no project activity of this type is currently (was) operational in the host country or region at the time of planning or implementation of the project activity.

Transparent and documented evidence needs to be provided, and conservative interpretations of this documented evidence offered to demonstrate the existence and significance of the identified barriers.

<u>If step 3 is satisfied, then step 4 of the eligibility assessment should be analyzed.</u>

Step 4: Common Practice Analysis

An analysis of the extent to which the proposed project type (e.g. technology or practice) has (have) already diffused in the relevant sector and region at the time of planning or implementation of the project activity needs to be included. The intent is to provide a credibility check to complement the investment analysis *(Step 2)* or barrier analysis *(Step 3)* discussed earlier.

If similar activities are (were) widely observed and commonly carried out then it is necessary to demonstrate why the existence of these activities does not contradict the claim that the proposed project activity is (was) financially unattractive or subject to barriers. This could be addressed by comparing the proposed project activity with the other similar activities, and pointing out essential distinctions between them that could explain why the similar activities enjoyed certain benefits that rendered them financially attractive *(e.g., subsidies or other financial flows)* or did not face the barriers to which the proposed CDM project activity is (was) subject. There could be serious fundamental and verifiable change in circumstances under which the proposed CDM project activity is implemented when compared to circumstances under which similar projects were carried out. For example, new barriers may have arisen, leading to a situation in which the proposed CDM project activity would not be implemented without the incentive provided by the CDM.

<u>If step 4 is satisfied, then step 5 of the eligibility assessment should be analyzed.</u>

Step 5: Impact of CDM Registration

An explanation needs to be provided on how the approval and registration of the proposed CDM project activity, and the attendant benefits and incentives derived from the project activity, would alleviate the economic and financial hurdles *(Step 2)* or other identified barriers *(Step 3)*. A project activity is CDM eligible if step 5 is passed.

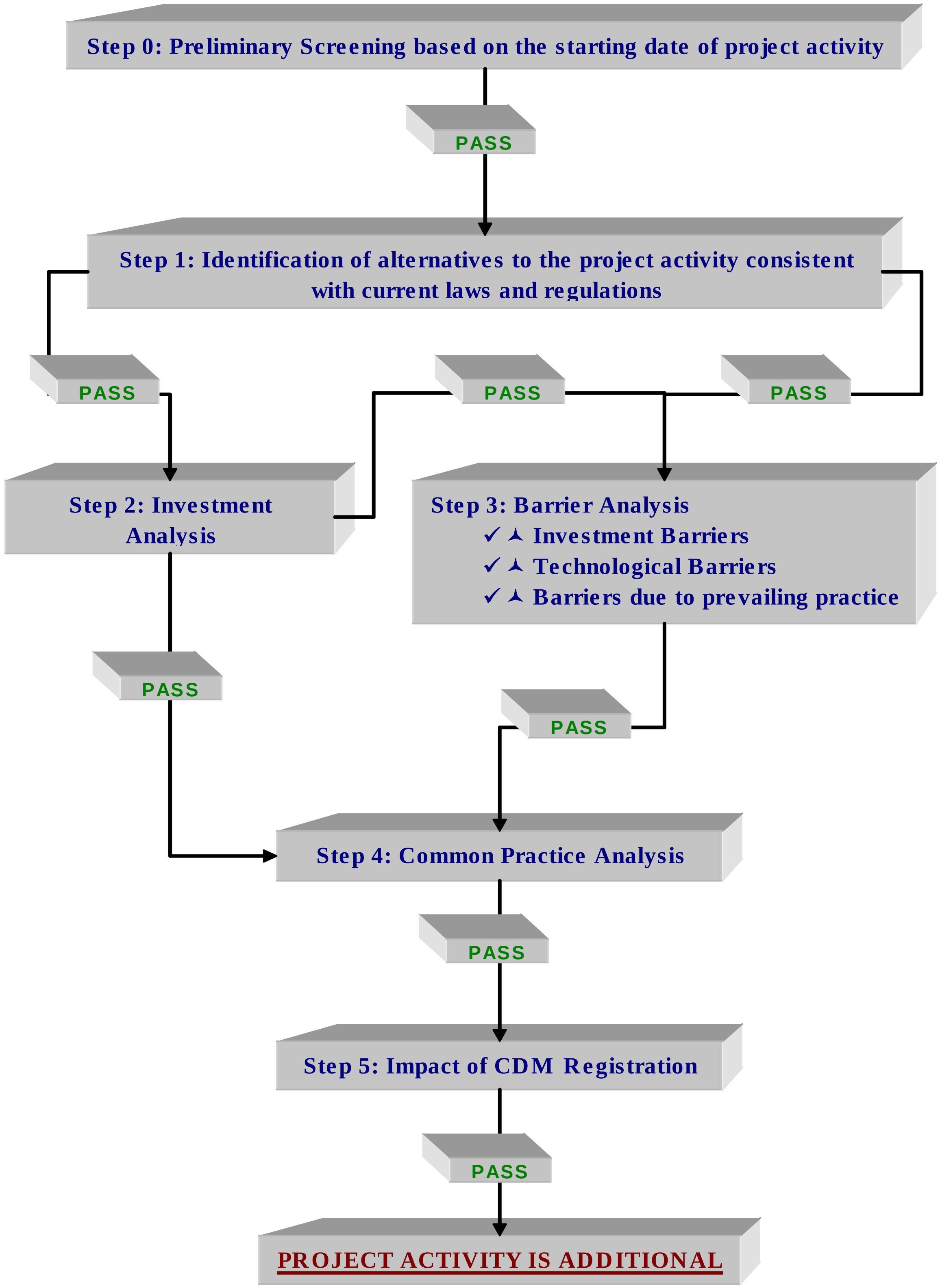
The step-wise eligibility assessment is depicted in the accompanying chart.

In addition to fulfilling the above requirements, the potential project needs to demonstrate the following:

- ✓ that it fulfils the sustainable development criteria of India; as per the Ministry of Environment and Forests (MoEF), these criteria include environmental well-being, technological well-being, social well-being and economic well-being;

- ✓ that no diversion of overseas development assistance funds to India would be used on the project;

- ✓ that the applicability conditions as per the approved CDM methodology are satisfied by the project.


Step 0: Preliminary Screening based on the starting date of project activity
PASS
Step 1: Identification of alternatives to the project activity consistent with current laws and regulations
PASS
PASS
PASS
Step 2: Investment Analysis
Step 3: Barrier Analysis
Investment Barriers
Technological Barriers
Barriers due to prevailing practice
PASS
PASS
Step 4: Common Practice Analysis
PASS
Step 5: Impact of CDM Registration
PASS
PROJECT ACTIVITY IS ADDITIONAL

6.2 An Overview on Internal Process requirements

In order to meet the requirements of section 6.1, the project proponent needs to institute the following internal administrative processes:

- collect evidences to demonstrate that the CDM project started after 1 January 2000 and at or prior to the start of the project activity CDM was seriously considered in the decision to proceed with the project activity; such evidences could be official, legal and/or other corporate documentation;

- collect evidences on all costs, incomes and revenues, and other benefits, based on which indicators for demonstrating investment barrier can be calculated, if this step is used for demonstrating CDM eligibility;

  if benchmarking approach is used, information on the following types of benchmarks should be collected:

  - *government bond rates, increased by a suitable risk premium to reflect private investment and/or the project type, as substantiated by an independent (financial) expert;*

  - *estimates of the cost of financing and required return on capital (e.g. commercial lending rates and guarantees required for the country and the type of project activity concerned), based on bankers views and private equity investors/funds' required return on comparable projects;*

  - *a company internal benchmark (weighted average capital cost of the company) if there is only one potential project developer (e.g. when the project activity upgrades an existing process). The project developers shall demonstrate that this benchmark has been consistently used in the past, i.e., that project activities under similar conditions developed by the same company used the same benchmark.*

  If sensitivity approach is used, information should be collected to demonstrate whether the conclusion regarding the financial attractiveness of the project is robust to reasonable variations in the critical assumptions.

- the project proponent should implement an appropriate operational and management structure to monitor emission reductions and any leakages;

- the project proponent should take views of the local stake-holders[19] who are affected or likely to be affected by implementation of the CDM project, and include such views in the project management plan;

- the project proponent should use a monitoring and verification protocol and plan which could be used to measure the annual emission reductions; this should include provisions on quality assurance and quality control (QA/QC), appropriate monitoring equipment and standard methods for measurement and equipment calibration for parameter

[19] Public, including individuals, groups or communities.

that will be used to calculate emission reductions; and

- an environment assessment for the CDM project should have been completed to understand if there would be any associated significant impacts; in case there is any, the same needs to be mitigated through appropriate planning.

In addition to the above, the project proponent needs to identify a focal point(s) to represent it on all communications with the MoEF, CDM EB and buyers of CERs. The CDM process cycle discussed under section 6.3 would be useful in understanding the need for such a focal point and also what external administrative process requirements exist in CDM.

6.3 CDM Process Cycle

The main stages in the CDM process cycle are discussed below and depicted earlier in a flow chart under section 1.3 of this report.

Stage I: Preparation of Project Design Document (PDD) and Project Concept Note (PCN).

This stage of project development is completed based on project data/ information for demonstrating CDM eligibility of a project and calculation of emission reductions including monitoring and verification plan. Also includes are information of environmental impacts of the project activity and views of local stake-holders, and how these are addressed in the project implementation plan.

The formats[20] for preparing the PDD are different for large scale project activities and small-scale project activities. Small scale project activities are defined as per one of the following three criteria:

1. **TYPE I – Renewable Energy Projects** *(capacity <15 MW)*;

2. **TYPE II – Energy Efficiency Improvement Projects** *(energy savings <15 GWh per annum)*; and

3. **TYPE III – Other Project Activities** *(with project emissions <15,000 Tco_2 per annum)*.

Any project activity that does not fit any of the above three criteria is generally a large scale project activity.

Stage II: Host Country Approval[21] (HCA).

This is provided by the Government of India (GOI) in the Ministry of Environment and Forests (MoEF), who are the designated national authority (DNA) for the GOI. For obtaining the HCA, project proponent needs to submit 20 copies each of the PDD and PCN, and 2 CD-ROMs with soft-copies of PDD and PCN, under a covering letter to the MoEF. Based on a review of the submitted information, MoEF requests the project proponent to make a presentation to its Climate Change Division about how the sustainable development goals of India would be met in the project activity. This presentation is also attended by

[20] Refer link # 6 under "Principle References and Links".

[21] Refer link # 4 and 5 under "Principle References and Links".

representatives of different ministries and expert groups.

Upon successful presentation of the project activity credentials on sustainable development, the HCA is normally accorded to a CDM project activity. The MoEF does not charge any fee for providing the HCA to a project.

Stage III: Validation of project by a Designated Operational Entity (DOE)[22]*.*

A DOE appointed by the project proponent reviews the PDD, conducts site visit to review project boundary/ configuration, check project data and monitoring and verification plan, reviews environmental impact assessment findings, reviews stake-holders comments, reviews the HCA issued by the DNA, etc. in the form of a detailed audit. Simultaneously, the DOE also puts up the PDD on the UNFCCC website for international stake-holder review and comments, if any.

The PDD must also specify what type of crediting period is selected by the project participant, who may choose between a 10-year fixed crediting period (where baseline remains unaltered throughout) or a renewable crediting period of 21 years (3 * 7 years, where, the baseline is recalculated at the beginning of the 8th year and 15th year).

Based on these activities, a draft validation report is issued to the project proponent with opportunities: (1) to provide clarifications on issues not fully understood by the DOE, (2) to reply to Corrective Action Requests if certain issues are not addressed properly either in the PDD or in the project activity, as per the DOE, and (3) to provide satisfactory replies to any comments from international stake-holders.

This stage of the project activity may be conducted in parallel to *Stage II* if the PDD for project activity is completed as per an approved CDM methodology.

Stage IV: Submission of request for registration of the project activity by the appointed DOE, and its registration by the CDM Executive Board.

Once the DOE is satisfied that all issues are addressed, it prepares the final validation report and submits it to the UNFCCC with an updated version of the PDD *(as necessary based on the validation exercise)*, and with modalities for communication with the project participant and registration fee. The registration fee varies with the projected quantum of CERs to be generated annually from a project activity.

Average tonnes of CO2 equivalent reductions per year over the crediting period (estimated/approved)	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

The stages of CDM process cycle discussed above do not include identification of ANNEX I buyer(s) of CERs; this(these) could be added to a project activity before or after its registration.

[22] Refer link # 3 under "Principle References and Links".

Stage IV: Realization of CDM Revenue.

A registered project activity will be annually verified for actual emission reductions (each year of the crediting period) by a DOE to be appointed by the project proponent, who in turn will submit request for issuance of CERs to the CDM Executive Board. The issued CERs can be transferred to an ANNEX I buyer and CDM revenue realized, through forward contract or any other mutually agreeable contractual mechanism, as discussed under section 1.4 of this report.

6.4 An Overview on External Process requirements

As discussed under section 6.3, the following external administrative processes are involved in the CDM process cycle until realization of the CDM revenue:

- interact with local stake-holders who could be affected by the CDM project and obtain their views on the projects impacts, and incorporate such views in project implementation if required;
- obtain HCA for a proposed CDM project from the GOI through the MoEF;
- appoint a DOE to validate the CDM project and have a request for registration submitted to the CDM EB;
- appoint a DOE to annually verify the emission reductions from the CDM project and have request for issuance of CERs submitted to the CDM EB; and
- interact with potential buyers of CERs (from ANNEX I countries) and formalize agreements for sale of CERs. The types of documentation involved in a typical transaction of CERs are 'term sheet' and 'emission reduction purchase agreement (ERPA)'.

The finalization of transaction agreements with buyers in ANNEX I Parties could be based on several considerations:

- ✓ existing and expected prices of the CERs in the international emission trading markets; several private entities like 'Point Carbon', 'CO2e.com', etc., provide information on current CER prices and future projects and forecasts;
- ✓ vintage of CERs available or would be available for transaction;
- ✓ volume of CERs available or would be available for transaction;
- ✓ credentials of the project proponent (host) who generates the CERs;
- ✓ if the CERs to be transacted belong to a project already registered and verified, or only registered but not yet verified, or from a project not yet registered and if so what is the stage of progress of the project before registration.

7

Action plan for Downstream Oil and Gas sector in India to harness carbon credits

7.1 Developing Processes and Administrative Protocols and Controls for CDM Revenue Realization

The information provided in the previous six chapters in this report may be used to develop processes and internal administrative protocols for realization of CDM benefits.

Based on the information provided in this report, any member refinery business of PetroFed may take the following steps for realizing CDM benefits from projects already started (after 1 January 2000) and those yet to be started or in planning stages.

1. designate a CDM team leader to co-ordinate to manage the internal administrative requirements for developing and structuring CDM projects across the operations of the member company; the team leader should report to the top management on progress of CDM related activities in the company; the team leader is also expected to be the nodal point for company's interactions with the MoEF, CDM EB, DOEs and any stake-holders for all external communications;

2. CDM team leader to put in place internal team who would be provided awareness training on identification of initiatives (past, current or proposed) that could be structured as CDM projects;

3. the internal team, with appropriate training, to identify potential CDM projects; a questionnaire survey may be run across operations and departments to trace potential CDM opportunities, and identify revenue potential as per guidance provided under Chapter 6 of this report.

4. the co-coordinator to discuss technological options, funding provisions, future CER transaction issues with the CDM team and with potential ANNEX I buyers of the CERs; viable and achievable projects should be developed keeping in mind the anticipated cash flow pattern from start of project preparation for CDM till the end of the crediting period;

5. the internal team to prepare necessary documentation (PDD, PCN, etc.) for Host Country Approval and project validation; assistance of 3rd party advisors could be taken if felt necessary; additional documentation such as new baseline and monitoring methodologies may need to be

developed in case approved CDM methodologies are not available.

6. team leader to manage all requirements until registration of each CDM project;

7. team leader to work with the company management and potential buyer(s) of CERs to finalize ERPA for sale of CERs;

8. team leader to co-ordinate with the internal CDM team and an appointed DOE to ensure the verification of actual CERs is completed each year and these are transferred to the buyer(s) account against CDM revenue payment.

7.2 Way Forward

The processes for realizing CDM benefits have been explained earlier. It is to be noted here that to strategize, structure, process and register a CDM project activity with approved methodology, it would take at least 8 months of activities. Whereas, for any CDM project activity without an approved methodology, it would take at least 18 months up to registration by the CDM EB at the UNFCCC. Therefore, it is important that all initiatives identified as potential CDM project activities are looked into expeditiously, keeping the following issues in mind:

- ✓ prompt crediting can be availed if project had started after 1 January 2000, validation was initiated by DOE initiated within 31 December 2005, and registration by UNFCCC is completed within 31 December 2006;

- ✓ VER market (at low prices) is still available for those projects that have missed the above deadlines;

- ✓ structure initiatives into CDM opportunities as soon as possible; plan based on type of project/ technology/ hurdles; indicative current estimates are: time-frames (6 – 18 months) and costs (Rs. 15 – 25 lakhs);

- ✓ plan ahead for 2nd Commitment Period (post-2012) and strategize industry approach to prepare the sector reap future benefits;

- ✓ strategize approach to future markets under Asia-Pacific Initiatives; and

- ✓ strategize actions for tapping voluntary markets.

Each member oil company may, either independently or in partnership with another member company, institute processes for identification and development of CDM projects. The partnerships could result in transfer of specific technical knowledge about operations, practices, type of financial hurdles perceived by company managements while deciding on a project, etc.

It is expected that PetroFed could play an important role in knowledge sharing, capacity building and process facilitation functions on behalf of the member companies. PetroFed could also act as the industry representative for this sector and discuss with the government, UNFCCC, stake-holders, technology suppliers, etc. on how to maximize CDM benefits for GHG mitigation initiatives taken or to be taken in the sector.

References and Links

1. http://cdm.unfccc.int/methodologies/PAmethodologies/AdditionalityTools/Additionality_tool.pdf

2. http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html

3. http://cdm.unfccc.int/DOE

4. http://cdm.unfccc.int/DNA/#I

5. http://cdmindia.nic.in/

6. http://cdm.unfccc.int/Reference/Documents

7. Economic Survey 2005-2006, website: http:/indiabudget.nic.in

8. Impact of High Oil Prices on Indian Economy, a report by FICCI in May 2005.

9. Mid term year Review of Tenth Five Year Plan.

10. A report on "Oil and Gas" sector prepared by PricewaterhouseCoopers Pvt. Ltd. (PwC) in January 2006 for India Brand Equity Foundation.

11. www.pointcarbon.com/

12. www.natcomindia.org/

13. www.wupperinst.org

14. http://www.fluorocarbons.org/en/info/brochures/fact_09.html

List of Acronyms

AA:	Assigned Amount
AAU:	Assigned Amount Units
APM:	Administered Price Mechanism
ATF:	Aircraft Turbine Fuel
BIS:	Bureau of Indian Standards
BPCL:	Bharat Petroleum Corporation Limited
CAGR:	Compounded Annual Growth Rate
CCGT:	Combined Cycle Gas Turbine
CDM:	Clean Development Mechanism
CDM EB:	CDM Executive Board
CER:	Certified Emission Reductions
CFC:	Chlorofluocarbons
CH_4:	Methane
CO:	Carbon Monoxide
CO_2:	Carbon Dioxide
COP:	Conference of Parties
CR:	Candidate Refinery
DNA:	Designated National Authority
DOE:	Designated Operational Entity
EIT:	Economies In Transition
ERPA:	Emission Reduction Purchase Agreement
EUA:	European Union Allowance
EU:	European Union
EU-ETS:	European Union Emissions Trading Scheme
FCC:	Fluidized Catalytic Converter
FCCU:	FCC Unit
FICCI:	Federation of Indian Chamber of Commerce and Industries
GAIL:	Gas Authority of India Limited
GEF:	Global Environment Facility
GHG:	Greenhouse Gases
GOI:	Government of India

GWh:	Giga Watt hour
HCA:	Host Country Approval
HFCs :	Hydrofluorocarbons
IET:	International Emission Trading
INC:	Intergovernmental Negotiating Committee
IOC:	Indian Oil Corporation
IPCC:	Intergovernmental Panel on Climate Change
IRR:	Internal Rate of Return
ITL:	International Transaction Log
JI:	Joint Implementation
KP:	Kyoto Protocol
LDCs:	Least Developed Countries
LNG:	Liquified Natural Gas
LPG:	Liquified Petroleum Gas
MEK:	Methyl Ethyl Ketone
MIBK:	Methyl Isobutyl Ketone
MMT:	Million Metric Tonnes
MMTPA:	Million Metric Tonnes Per Annum
MoPNG:	Ministry of Petroleum and Natural Gas
MoEF:	Ministry of Environment and Forests
MS:	Motor Spirit
MW:	Mega Watt
NATCOM:	National Communication to the UNFCCC
NIGEC	National Iranian Gas Export Co. Ltd.
N_2O:	Nitrous Oxide
NOC:	National Oil Companies
NOx:	Oxides of Nitrogen
NPV:	Net Present Value
OECD:	Organisation for Economic Co-operation and Development
OMC:	Oil Marketing Companies
PCN:	Project Concept Note
PDD:	Project Design Document
PDS:	Public Distribution System

PetroFed:	Petroleum Federation of India
PFCs:	Perfluorocarbons
PLL:	Petronet LNG Limited
PoL:	Petroleum, Oil Lubricants
PSU:	Public Sector Units
PwC:	PricewaterhouseCoopers (P) Ltd.
QA/QC:	Quality Assurance and Quality Control
SBI:	Subsidiary Body for Implementation
SBSTA:	Subsidiary Body for Scientific and Technological Advice
SF_6:	Sulphur hexafluoride
SPA:	Sale Purchase Agreement
SOx:	Oxides of Sulphur
UNFCCC:	United Nations Framework Convention on Climate Change
VER:	Verified Emission Reductions
VOC:	Volatile Organic Compounds
WCC:	World Climate Conference
WHRB:	Waste Heat Recovery Boiler