Strategies to Reduce GHG Emissions from India's Coal-Based Power Generation

The Energy and Resources Institute
www.teriin.org

Discussion Paper
May 2009

Disclamer

This paper was produced as a reference paper to inform the discussion paper "New Mechanisms for Financing Mitigation: Transforming economies sector by sector." The views expressed in this paper do not represent the views of WWF nor the agencies that committed financial support to carry out this project.

Strategies to Reduce GHG Emissions from India's Coal-Based Power Generation

The Energy and Resources Institute

www.teriin.org

Project Report No. 2008IE14

Paper prepared for WWF, India

New Delhi

May 19, 2009

An Introduction to the Global Financial Mechanism Supporting Studies Series

Beginning in mid-2008, at the request of several European governments, WWF led an analysis and dialogue on international financing arrangements to address climate change in developing countries. That meant, on the one hand, advancing a technically strong proposal capable of mobilizing the considerable public and private funds that may be needed to attain the below 2 degrees centigrade goal for climate change stabilization and, on the other hand, advancing an equitable proposal that could garner the support of the parties at COP15.

The work approach is designed (a) to bring a bottom-up perspective to the to the current top-down discussion, based on a suit of developing countries' sectoral studies that focus on what it would actually take to move whole economic sectors towards a low emission trajectory; (b) to focus on the operational requirements of an international financing scheme; (c) to engage leading experts on a critical review of relevant experiences and government proposals; (d) to convene experts and negotiators from South and North to discuss these issues; and (e) to present the project findings to key stakeholders and forums in the run-up to COP15.

The program's main conclusions and proposals are in the document: "Global Financial Mechanism. The Institutional Architecture for Financing a Global Climate Deal" that can be downloaded from http://www.panda.org/what_we_do/how_we_work/policy/macro_economics/our_solutions/gfm/

In this Supporting Studies Series we are presenting a dozen reports that were used as inputs to the project. All these studies were commissioned to independent experts or institutions. Some are case studies of mitigation opportunities in different sectors of developing countries (e.g. cement and iron & steel in China and Mexico, coal based power generation in India, renewable energy opportunities in Morocco). Others are stock-taking reports focusing on critical issues for the global climate change financing (e.g. mapping new financing options for climate change, a review of sectoral mitigation proposals, a review of proposals to fund technology cooperation, etc.).

Some of the ideas and proposals in these support series have been carried over to the project recommendations and have been summarized in the main document (either as short summaries, theme boxes, or pull quotes). Still, these documents have much more to offer, and for that reason we present them here in full. As usual, opinions in each document are the sole responsibility of its author(s), and should in no way be considered representative of WWF positions.

Authors and titles in this GFM Supporting Studies Series include:

1. Michael Rock; (Bryn Mawr College) Using External Finance to Foster a Technology Transfer-Based CO_2 Reduction Strategy in the Cement and Iron and Steel Industries in China
2. Christine Woerlen (Arepo consult, Berlin) ; "Opportunities for renewable energy in Tunisia: A country Study
3. The Energy and Resources Institute (TERI, Delhi) "Strategies to reduce GHG emissions from India's coal-based power generation"
4. Britt Childs with Casey Freeman (WRI, Washington DC) "Tick Tech Tick Tech: Coming to Agreement on Technology in the Countdown to Copenhagen"
5. Energia, Tecnologia y Educacion, SC (ETE, Mexico DF) "Strategies to reduce Mexico's cement and iron & steel industry GHG emissions"
6. Charlotte Streck (Climate Focus, Brussels) "Sectoral Transformation Plans as Strategic Planning Tools"

7. Charlotte Streck (Climate Focus, Brussels) “Financing REDD a Review of Selected Policy Proposals
8. Charlotte Streck (Climate Focus, Brussels) “Financing Climate Change: Institutional Aspects of a Post-2012 Framework”
9. Silvia Magnoni “Review of the CDM and Other Existing and Proposed Financial Mechanisms to Transfer Funds from North to South for Mitigation and Adaptation Actions in Developing Countries”
10. Silvia Magnoni “Sectoral approaches to GHG mitigation and the post-2012 climate framework”
11. Weishuang Qu (Millennium Institute, Washington DC) “Using the T21 computing model to forecast production and emissions in China’s cement and steel sectors”
12. Neil Bird et al (ODI, London) “New financing for climate change. And the environment in the developing world”

Contents

List of Acronyms

AAU	assigned amount unit
ACM	Approved Consolidated Methodology
AIFI	All India Financial Institution
APDRP	Accelerated Power Development and Reform Programme
APGENCO	Andhra Pradesh Power Generation Corporation Limited
ASCU	all subcritical units only
AWG-LCA	Ad-hoc Working Group on Long-term Cooperative Action
BAU	business as usual
BHEL	Bharat Heavy Electricals Limited
BkWh	billion kilowatt-hour
BU	billion units
CCS	carbon capture and storage
CDM	Clean Development Mechanism
CEA	Central Electricity Authority
CER	certified emission reduction
CIF	Climate Investment Fund
CO_2	carbon dioxide
CSEB	Chhattisgarh State Electricity Board
CV	calorific value
EB	Executive Board
ECA	export credit agency
ECB	external commercial borrowing
EE	Energy Efficiency
EPS	Electric Power Survey
ETF-IW	Environmental Transformation Fund – International Windows
FDI	foreign direct investment
G77	Group of 77
GCCA	Global Climate Change Alliance
GDP	gross domestic product
GEF	Global Environment Facility
GHG	greenhouse gas

GNDTP	Guru Nanak Dev Thermal Plant
GOI	Government of India
GW	gigawatt
HDI	Human Development Index
HYB	hybrid
IEA	International Energy Agency
IFCI	International Forest Carbon Initiative
IGCC	Integrated Gasification Combined Cycle
IIFCL	India Infrastructure Finance Company Limited
INR	Indian rupee
IPP	independent power producers
IPR	intellectual property rights
IREDA	India Renewable Energy Development Agency
JV	joint venture
kCal	kilocalorie
KRW	Kellogg Rust Westinghouse
kt	kiloton
kWh	kilowatt-hours
L&T	Larsen and Toubro
LNG	Liquified Natural Gas
MAHAGENCO	Maharashtra State Power Generation Co. Ltd
MDB	multilateral development bank
MDG	Millennium Development Goals
mg/Nm^3	milligrams per normal cubic meter
MHI	Mitsubishi Heavy Industries
Mt	megatonne
MW	megawatt
NAPCC	National Action Plan on Climate Change
NCES	nonconventional energy sources
NCTP	National Capital Thermal Power
NEP	National Electricity Plan
NO_X	nitrous oxides
NTPC	National Thermal Power Corporation

PDD	Project Design Document
PFBG	pressurized fluidized bed gasifier
PFC	Power Finance Corporation Limited
PLF	plant load factor
PSEB	Punjab State Electricity Board
R	rupee
R&D	research and development
REC	Rural Electrification Corporation Limit
RGGVY	Rajeev Gandhi Grameen Vidyutikaran Yojna
SO_X	sulfur oxides
STP	Super Thermal Power
STPP	Super Thermal Power Project
STPS	Super Thermal Power Station
t	tonne
TERI	The Energy and Resources Institute
TTA	technology transfer agreement
TU	Technology Upgradation
TWh	terawatt hour
UMPP	ultra mega power project
UN	United Nations
UNDP	United Nations Development Programme
UNFCCC	United Nations Framework Convention on Climate Change
UN-REDD	United Nations Collaborative Programme on Reduced Emissions from Deforestation and Degradation.
UPRVUNL	Uttar Pradesh Rajya Vidyut Utpadan Nigam Limited
USAID	United States Agency for International Development
USC	ultrasupercritical

Chapter 1

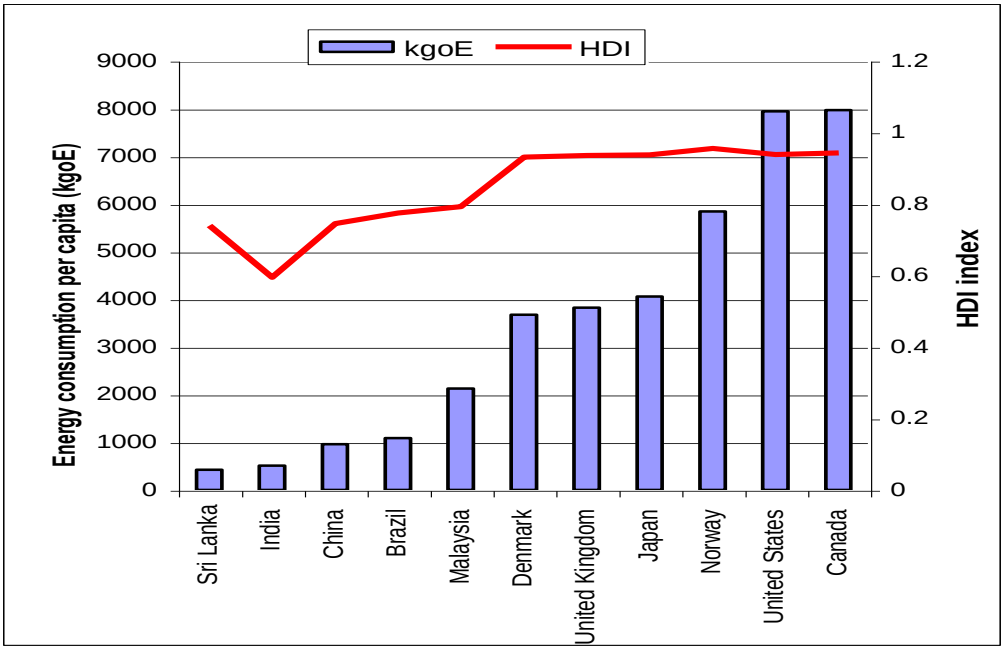
Introduction

India's Initial National Communication to the United Nations Framework Convention on Climate Change (UNFCCC) (2004)[1] reports that the energy sector, specifically energy and transformation industries, accounts for the largest share in total national greenhouse gas (GHG) emissions. The energy and transformation industry sector is, in turn, constituted primarily by electric power generation.

Figure 1.1 shows the relationship between energy consumption levels and the Human Development Index (HDI) for various countries around the world. There is a clear correlation between levels of human development and per capita energy use. If India is to improve its HDI from the current level, it is imperative for it to increase its per capita energy use.

Government of India (GOI) Five-Year Plans indicate various sources through which this demand is going to be met. These include fossil fuels (coal, petroleum products, and natural gas), renewables, and nuclear. However, options such as nuclear and renewables would take time to materialize to the point at which they will be able to serve the country's major demand for energy. Until these sources significantly increase in magnitude, coal will continue to serve at an important position in the total fuel mix. From a power generation perspective, coal would continue to remain a major, if not primary, energy source.

Figure 1.1. Energy consumption levels vis-à-vis HDI for different countries



Sources: World Bank 2005; UNDP 2005.

[1] http://www.natcomindia.org/natcomreport.htm

Data indicates that approximately 53% of India's total installed power generation capacity is presently coal based (CEA 2008d). Coal-based thermal power generation therefore also accounts for the largest share in total GHG emissions within the power sector. Various projections (with varying assumptions regarding the driving forces) indicate that even in the future, coal-based generation will remain the mainstay in the Indian power sector in the next few decades. Studies by TERI (2006) as well as by the Planning Commission and Ministry of Power, GOI, indicate that approximately 58% of total installed capacity would be coal-based even by 2031–32. International sources such as the World Energy Outlook published by the International Energy Agency (IEA) also opine that approximately 69% of India's electricity generation in 2030 would be coal-based. Though the IEA assumes a 6.4% gross domestic product (GDP) growth rate for India during 2006–2030 (IEA, 2008), as compared with the GOI planned growth projection of 8%, leading to a variation in the total quantity of coal requirement, directionally all the studies indicate that coal would continue to remain important in the power generation sector. It is from this perspective that this study focuses on examining possible scenarios of growth as well as technological progress related to coal-based power generation in India until 2030, estimating the level of emission reduction that can be achieved with clean coal technologies, estimating the additional funding requirements of making such transitions, and suggesting mechanisms to facilitate this.

New clean coal technologies that reduce GHG emission from coal-based power generation have already been demonstrated in developed countries. India has also developed the Integrated Gasification Combined Cycle (IGCC) based on high-ash Indian coal. However, the scaling-up and deployment of these technologies in a commercially viable manner is a Herculean task for an already resource-scarce developing country like India.

From a developing country perspective, the application of these new technologies implies that choices are to be made between "cleaner" technologies over inherently cheaper technology such as subcritical steam cycle pulverized coal power generation. In addition, the introduction of cleaner technologies may face other barriers such as paucity of funds to fill up the viability gaps, technological risks inherent in the application of a technology in a new setting, lack of indigenous capacity, and so on. In this regard, the development of a suitable financial mechanism for the transfer of funds and technology from the developed to the developing countries could facilitate this transition and allow it to occur more rapidly.

This study has examined the technological options relevant to India for reduction in GHG emissions in the coal-based thermal power generation sector. The status of different coal-based power generation technologies, progress with respect to their implementation, plans for movement toward alternative technologies, and the barriers to this transition have been analyzed. The emission reduction potential of alternative technologies has also been projected. The assessment has been made over a time horizon ending 2031–32. Efforts have been made to suggest a mechanism for funding the incremental costs required to implement the cleaner technologies.

Chapter 2

Coal-based power generation scenario

2.1 Present scenario

The total installed capacity in the country (excluding captive power plants) increased from 132,329 megawatts (MW) on March 31, 2007, to 143,061 MW on March 31, 2008 (CEA 2009).

Figure 2.1.1. Installed capacity in India in terms of fuel mix, as of March 2008

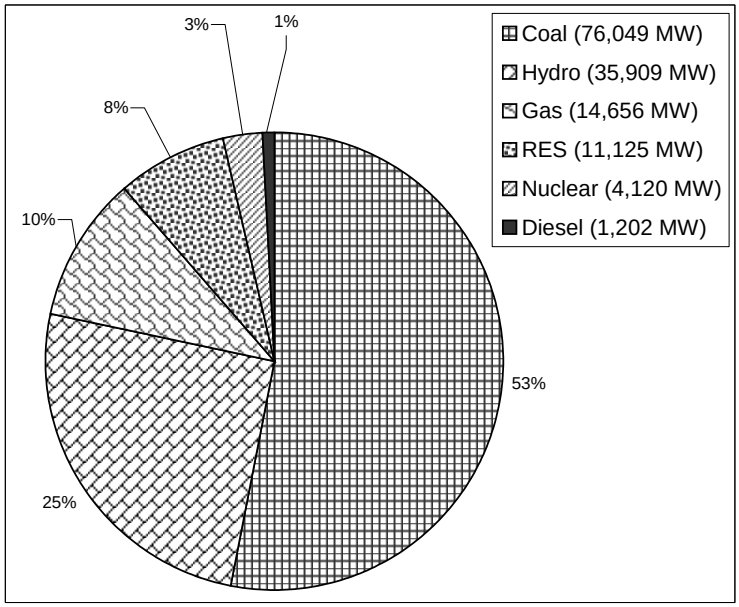
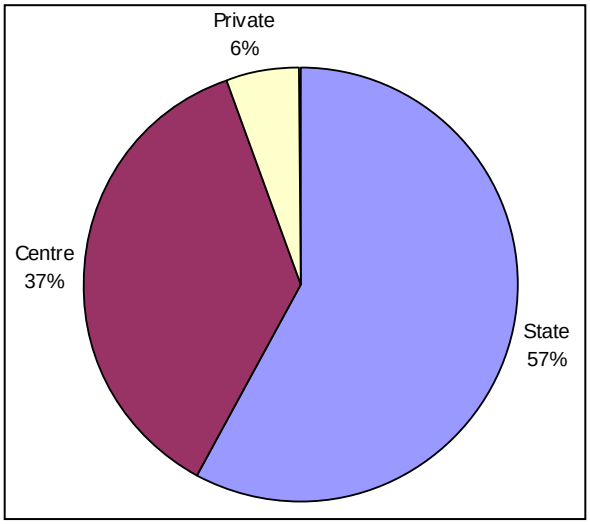


Figure 2.1.1 gives the breakup of the energy sources for power generation. Out of the total installed capacity, 76,049 MW is from coal- and lignite-based power plants. Most of this capacity lies with the public sector (nearly 94%), with just about 6% in the private sector (figure 2.1.2). The public sector constitutes the units owned by both the central government and the state government.

Figure 2.1.2. Installed capacity in coal-based power plants with respect to ownership



Coal has been the mainstay of India's energy supply for many decades, given the relatively large indigenous resources of coal as compared with other fuels in India. Coal consumption in the country increased from 213 million tonnes in 1990–91 to more than 450 million tonnes in 2007–08, of which more than 70% has been for power generation alone.

Power generation capacity has also remained coal dominated because of the relatively large availability of coal as well as its favorable economics when compared with other alternatives. Although power generation based on gas would be relatively cheaper, the availability of gas is limited. Moreover, the fertilizer sector has a preference for gas supply over the power sector. In 2008, thermal power plants using coal accounted for 53% of the total generation capacity.

2.2 Future plans

Future energy requirements of the country are determined by basic socioeconomic driving forces such as population and GDP growth as well as structural changes in the economy and consumption patterns caused by changing lifestyles. India's per capita electricity consumption is around 650 kilowatt-hours (kWh) and more than 50%[2] of India's rural population still does not have access to electricity. Given that the government has plans to maintain an economic growth of around 8% over the next few decades in order to address its developmental goals of poverty reduction, major transitions in consumption levels and patterns in the future are expected.

This section discusses the growth and planned projections (over Five-Year Plan periods) of the GOI in the power sector, with respect to capacity addition for coal-based power plants. On the basis of expert judgment, the likelihood of achieving these planned projections has been evaluated and presented in the form of three cases (the pessimistic case, the base case, and the optimistic case) for the 11th Plan period. The 12th Plan capacity addition requirements as estimated by the Central Electricity Authority (CEA) and in the National Electricity Plan (NEP) are discussed and the long-term projections as put forward by various studies including the TERI study and the IEA estimates are compared.

2.2.1 11th Five-Year Plan Period (2007–12)

The Integrated Energy Policy document prepared by the Planning Commission, GOI, stipulates power generation to grow at the rate of 9% per annum during the 11th Plan. CEA, in its NEP, has projected the likely levels of installed capacity that will be needed during the 11th and 12th Plan periods. The 17th Electric Power Survey (EPS) Committee's Report has been considered by the CEA for planning the capacity addition and detailed information regarding existing power plants and those cleared for construction in future have been considered for the short-term estimation.

The NEP states that electricity generation in the country should reach 1,038 BkWh (billion kWh) by the year 2011–12, based on a per capita consumption of 1,000 kWh. The 17th EPS and the Integrated Energy Policy Report stipulate the generation to be of similar levels, at 1,036 BkWh and 1,008 BkWh, respectively. Because the demand as per the NEP is the highest, requirement of generation (from utilities) adopted for planning purpose was considered as 1,038 BkWh. As per the NEP report, this would require a generation growth rate of 9.5% per annum for utilities. The 17th EPS report stipulates peak demand of 215,800 MW by 2011–12, and this has also been considered by CEA while assessing the 11th Plan capacity addition.

[2] Source: http://regserver.unfccc.int/seors/attachments/file_storage/jc52uowpyhf2a0l.ppt

To meet the energy generation requirement of 1,038 BkWh and a 5% spinning reserve, a capacity addition of about 82,500 MW is required during the 11th Plan. However, on the basis of the preparedness of the projects, it is envisaged that a total capacity of about 78,530 MW (including hydro, coal, lignite, gas, and nuclear plants) will most likely be added as it consists of plants committed or already under construction. Of this, 54,355 MW (nearly 70% of the total addition) would be from coal-based power plants. A breakdown of ownership of this feasible capacity is given in table 2.2.1.1.

Table 2.2.1.1. Feasible for addition during 11th Plan period (2007–12) as per ownership (figures in MW)

Owner	Under construction		Committed		Total (MW)
	Coal	Lignite	Coal	Lignite	
Center	10,190	750	14,120	250	25,310
State	12,735	450	10,400	—	23,585
Private	2,700	—	2,760	—	5460
Total	25,625	1,200	27,280	250	54,355

Source: CEA 2007a

Of these projects, 26,825 MW are under construction (as of April 2007) and 27,530 MW are committed, meaning that these have reasonable certainty of materializing during the 11th Plan as they are under various stages of development, such as obtaining clearances, land acquisition, and detailed project report preparation. Table 2.2.1.2 gives details of the likely capacity addition in terms of its planned location and regional distribution (CEA 2007b). The location (i.e., pithead, load center, and coastal) of these plants is important to understanding the degree of logistical constraints that may arise in the timely completion of these projects.

Table 2.2.1.2. Location of plants under feasible capacity addition in 11th Plan (2007–12) (figures in MW)

Region	Coastal	Pithead[3]	Load Center	Lignite	Total
Northern	—	2,500	9,805	625	12,930
Western	500	9,090	6,210	325	16,125
Southern	3,800	500	4,560	500	9,360
Eastern	—	12,120	3,070	—	15,190
Northeastern	—	—	750	—	750
All-India	4,300	24,210	24,395	1,450	54,355

Source: CEA 2007b

In the present-day scenario, at the current price level of coal and railway transportation tariffs, the transmission of electricity from pithead power plants to load center works out to be a cheaper

[3] Pithead stations have their own dedicated coal transportation system (MGR/Ropeway) and are independent from railways for coal movement.

option compared with load center power plants at a distance greater than 300 km. However, certain factors warrant setting up load center thermal power plants as well. These are

- system stability/security
- security of state grid and emergency supplies to various critical systems in the state (e.g., railway, hospital, airports)
- taking care of emergencies in case of transmission systems failure
- dispersion of environmental degradation
- problems of right-of-way in case of construction of new transmission lines

Consequently, in the 11th Plan about 46% of coal-based capacity—that is, around 24,395 MW (table 2.2.1.2)—is likely to be set up at load centers.

In addition to the above, coal (including lignite) based plants totaling 11,545 MW have been identified as "best effort projects" (see table 2.2.1.3). These projects would normally be commissioned in the beginning of the 12th Plan. However, in case of any constraints in taking up of any of the projects included in the 11th Plan, some of these 12th Plan projects would be attempted for commissioning during the 11th Plan itself, depending on the preparedness of these projects at the appropriate time. Because these best effort projects can be expedited if required, we have included them as part of an optimistic case for the 11th Plan capacity addition. Also, efforts are under way to tap surplus power from grid-connected captive power plants. Therefore, including captive power plants, a total additional capacity of about 12,000 MW is likely to be commissioned during the 11th Plan period.

Table 2.2.1.3. Additional capacity addition during the 11th Plan (2007–12) based on "best effort projects" (MW)

Owner	Coal	Lignite	Total
Center	4,190	—	4,190
State	2,300	1,000	3,300
Private	4,055	—	4,055
All-India	10,545	1,000	11,545*

*Excluding likely captive power plants added during this period

The availability of coal for these projects has also been briefly looked into to verify the feasibility of these projects during the 11th Plan period.

The total coal availability from domestic sources is expected to be 482 megatonnes (Mt) per annum by 2011–12 (CEA, 2007b). Accordingly, imported coal of around 40 Mt (which is equivalent to 68 Mt of Indian coal) may have to be made available. So, the NEP report has projected a requirement of around 550 Mt of domestic coal (instead of 482 Mt) for 2011–12.

Table 2.2.1.4 provides the status of fuel supply/linkage for the total likely coal (excluding lignite) based capacity addition of 52,905 MW as per the NEP report.

Table 2.2.1.4. Coal supply security status, as per the NEP report

Supply linkage No.	Capacity (MW)	Status
1	37,975	Linkage allocated
2	6,580	Captive coal blocks allocated
3	24,210	Pithead based
4	24,395	Load center based
5	4,300	Coastal power plants
6	4,500	Linkages are yet to be allocated
7	2,500	Coal blocks are yet to be allocated
8	1,350	Likely to be based on imported coal; formal fuel supply arrangements yet to be made

Likely scenarios under the 11th Plan (2007–12)

Taking the feasible addition of capacity (i.e., 54,355 MW) from the NEP's thermal projections as the base case, there can be some addition or subtraction of the total coal-based capacity projections for the 11th Plan period. In an optimistic case, the additional capacities may come into being given certain enabling conditions, while in a pessimistic case (which takes into account the uncertainties of fuel supply/linkages), all of the planned capacity may not become productive, as indicated in table 2.2.1.5.

Table 2.2.1.5. Likely scenarios for capacity addition of coal-based plants during the 11th Plan

Case	MW
Base Case	54,355
Pessimistic Case	46,005
Optimistic Case	65,900

These figures do not include merchant power plants that are likely to come up in the 11th Plan period.

On the basis of further discussions with concerned officials and expert opinion, the expected addition of coal-based power plants will be only 42,480 MW (i.e., around 54% of total planned addition) during the 11th Plan period, which is even lower than the pessimistic case (58%). Accordingly, as a base for longer-term projections in the latter sections of this report, we assume that coal-based capacity addition would be in the range of 54% to 58% in the 11th Plan period.

Various studies that examine the future energy supply scenarios have indicated that the use of alternative fossil energy forms (natural gas) for power generation seem unlikely owing to several factors including availability, geopolitical considerations, and pricing. Renewables and nuclear, while important

in contributing to the growth in power sector development, are expected to be able to make a small contribution in percentage terms because of the rather small base despite rapid growth. The National Plans in the power sector have also relied heavily on thermal-based generation for adding base load capacities. Accordingly, coal would be expected to predominate in the future as well. Although domestic reserves may be able to cater to the demand for coal in the short term, coal imports are likely to increase rapidly over the long term to meet the future energy demands of the country.[4]

2.2.2 12th Plan Period (2012–17)

The projections of the 12th Plan period for addition of installed capacity were made based on the correlation of the country's GDP growth with growth in demand of electricity from the NEP report.

Likely Scenarios under the 12th Plan

Table 2.2.2.1 provides the figures of total installed capacity addition required for different growth rates during the 12th Plan period as per the NEP. After comparing three different GDP growth paths—8%, 9%, and 10%—the NEP report came out with recommendations for planning for the 9% GDP growth path. This would require a demand in generation of around 1,500 BkWh of electricity. As a result, an additional capacity in the range of 82,200 MW to 94,300 MW would be required.

Table 2.2.2.1. Total capacity addition required during the 12th Plan (2012–17)

GDP growth	GDP/ electricity elasticity	Electricity generation required (BU)	Peak demand (MW)	Installed capacity (MW)	Capacity addition required during 12th Plan (MW)
8%	0.8	1,415	215,700	280,300	70,800
	0.9	1,470	224,600	291,700	82,200
9%	0.8	1,470	224,600	291,700	82,200
	0.9	1,532	233,300	303,800	94,300
10%	0.8	1,525	232,300	302,300	92,800
	0.9	1,597	244,000	317,000	107,500

Table 2.2.2.2 provides the list of projects for going online during the 12th Plan period as prepared by CEA. This table indicates a likely capacity addition of about 94,185 MW from coal-based plants and 4,250 MW from lignite-based plants. Together these account for nearly 58% of the total listed capacity, which is higher than the 54% coal-based capacity addition that is likely to take place during the 11th Plan period. Of the 98,435 MW of coal- and lignite-based capacities to be added in the 12th Plan period, 11,545 MW may come up in the 11th Plan period itself with best efforts as considered in the optimistic case for the 11th Plan period in this report.

[4] Owing to the stringent environmental and forest conservation relation restrictions applicable to mining, there is a need for investments in dedicated transport infrastructure.

Table 2.2.2.2. List of projects for likely benefits during the 12th Plan period

Type	Capacity (MW)
Thermal	114,018
Coal	94,185
Gas/LNG	15,583
Lignite	4,250
Hydro	40,658
Nuclear	12,800
Total	**167,476**

In the longer term, given the government's interest in developing renewables and nuclear power plants, the share of coal-based power generation could change because of an increased installed capacity of renewables and nuclear power.

As per the latest CEA projections, the coal-based capacity that is likely to be added during the 12th Plan period is about 62,930 MW (Bakshi and Singh 2008; Planning Commission 2006).

2.2.3 Beyond the 12th Plan (2017–32)

As India's energy needs continue to grow, power generation capacity will have to grow correspondingly to cater to these demands. Coal-based power generation in India is expected to increase even after the 12th Plan period because of its economic attractiveness and the unlikelihood of other power generation technologies achieving significant penetration levels in the Indian power sector. The United Nations Human Development report for 2007–08 used IEA analysis to show that coal-based capacity will touch 251,000 MW by 2030–31 (table 2.2.3.1). This means an addition of approximately 200,000 MW (or 200 GW) of coal-based generation capacity will be needed in this time period.

Table 2.2.3.1. IEA projections for coal-based generation in India, as given in UN report (UNDP 2007/2008)

	2004 actual	2015	2030
Reference Scenario			
Coal-fired capacity (GW)	72	128	251
Coal-fired generation (TWh)	461	836	1631
Alternative Policy Scenario			
Coal-fired capacity (GW)	72	117	191
Coal generation (TWh)	461	765	1242

The estimates as per TERI's study for the GOI (TERI 2006) are provided in table 2.2.3.2. These projections were made for two cases: namely, BAU (business as usual) and HYB (hybrid). BAU represented energy development according to existing government plans and policies, and a GDP

growth rate of 8%. The HYB case incorporated energy efficiency, high penetration of renewable energy, and an aggressive pursuit of nuclear-based power generation into the BAU case.

Table 2.2.3.2. TERI projections as per the National Energy Map for India – Technology Vision 2030

Power generation capacity by 2031–32 (GW)	BAU	HYB
Coal	466	292
Natural gas	137	144
Hydro	158	160
Nuclear	21	70
Diesel	8	8
Renewables	4	26
Total	794	700

It should be noted, however, that the recent National Action Plan on Climate Change (NAPCC) (PMCCC 2008) sets direction for more penetration for renewable and nuclear in the future electricity scenario. It is expected that the role of coal may fall in the long term despite the fact that renewable technologies are currently relatively higher priced and commercially unviable. However, the quantitative impact of the NAPCC on the future energy scenario is not yet available.

2.3 Probable growth in coal-based power beyond 2007

As indicated in sections 2.1 and 2.2, different plans/studies provide different projections for the coal-based capacity additions across the various Plan periods. In addition to these studies, CEA has recently provided projections up to the 13th Plan as indicated in table 2.3.1.

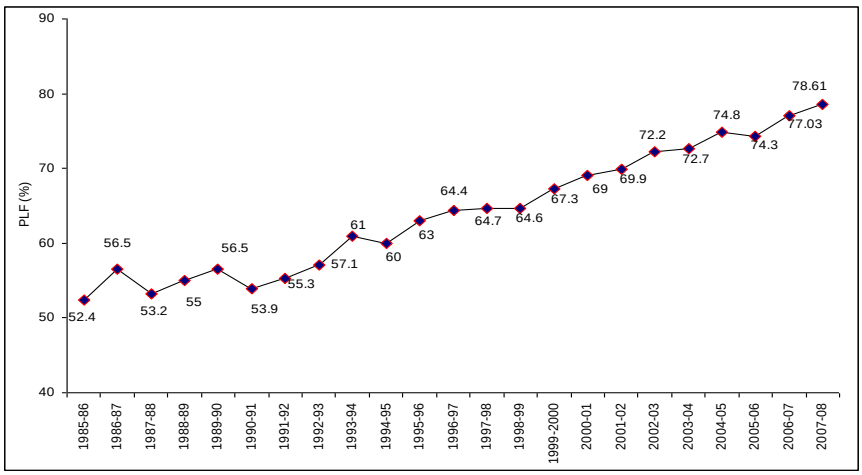
Table 2.3.1. Likely coal-based capacity addition and expected generation efficiency

End of the Plan	Coal-based capacity addition (MW)	Cumulative coal-based capacity (MW)	Total generation from coal-based plants (BkWh)	Expected gross thermal generation efficiency (%)
11th Plan (2007–12)	50,340	116,610	708	35.3
12th Plan (2012–17)	58,485	175,095	1164	36.4
13th Plan (2017–22)	56,500	231,595	1542	36.85

Source: CEA 2008e

Besides the generation capacity additions, there are consistent efforts to improve plant operations. This can be seen from the fact that the plant load factor (PLF) of thermal power plants has improved over the years, as shown in figure 2.3.1.

Figure 2.3.1 All-India PLF of coal-fired thermal power plants



The PLF has improved gradually from a very low level of 52.4% in 1985–86 to 77.03% by 2006–07, and further improved to 78.61% in 2007–08. This has been made possible through renovation and modernization of old power plants being promoted by the Ministry of Power, GOI, through Power Finance Corporation, and well-planned maintenance schedules that almost all the plants agree to follow, after power sector reforms. With sustained efforts, the PLF could further improve in the future. Large-capacity ultra mega power projects (UMPPs) are being designed to achieve a PLF of at least 85%. In view of this, it is felt that in the years to come, the average PLF will reach a level of 84% by 2031–32 as given in table 2.3.2.

Accordingly, for examining GHG emissions and technological growth, the assumptions for capacity addition and PLF for the period 2007–2032 are as provided in table 2.3.2. The installed capacity of coal-based power plants comes out to be 416,506 MW.

Table 2.3.2. Projected growth of coal-based thermal power and PLF

Year/Period	Capacity addition (MW)	Installed capacity by end of period (MW)	Projected average PLF (%)
As of March 2007		67,596*	77.03
2007–12	42,480**	110,076	79.00
2012–17	62,930 [a, b]	173,006	80.00
2017–22	56,500 [a, b]	229,506	81.00
2022–27	79,000a[a, b]	308,506	82.00
2027–32	108,000[a, b]	416,505	84.00

*Performance of thermal power plants for 2006–07, CEA report

**Expected addition during the 11th Plan

[a]Projections for capacity additions (Bakshi and Singh 2008)

[b]Planning Commission, 2006

The projected installed capacity of coal-based plants by year 2032, as estimated by CEA, is 412,000 MW (CEA 2007b), and closely matches the projections given in table 2.3.2. TERI estimates as per the BAU scenario in the National Energy Map Report (TERI 2006) were slightly higher at 466 GW in 2031–32.

Chapter 3

Technological progress in coal-based thermal power sector

3.1 Technology progress until 2007–08

Coal-based thermal power generation involves two basic technologies: (a) the combustion technology to produce steam in boilers and (b) the steam-to-electricity generation technology, which uses the steam turbine and the turbo-generator. The efficiency of electricity generation, that is, from fuel to electricity, is dependent on the efficiency of each of the two systems individually. Each has progressed throughout the world in the past 50 to 60 years. However, the technology has progressed much more in the developed countries than in the developing countries.

India embarked on accelerated industrial development after independence in 1947. The total installed capacity of power generation in the country was only 1,330 MW in August 1947, and the capacity of individual units for thermal power generation was in the range of 10 to 30 MW. The boilers had stoker firing combustion system and the steam turbines were run at lower inlet steam temperature because materials that could withstand higher temperature over prolonged periods of operation were unavailable.

Thermodynamically, higher steam parameters give higher efficiency of conversion of heat energy to mechanical energy. Thus, the overall efficiency of the power plants was low. In addition, the indigenous capacity did not exist for design and manufacture of the heavy equipment required for the power plants.

Since the past 60 years, great progress has been made and the total power generation installed capacity, as of March 31, 2008, has reached 143,061 MW. Out of this, coal-based power generation is 76,048 MW. Pulverized coal combustion technology has been adopted for units of capacity 60 MW and above. The steam cycle efficiency of these plants has improved over the years with increase in capacity of individual units. For every increase in unit capacity, higher steam parameters as given in table 3.1.1 have been adopted. This resulted in gradual improvement in overall generation efficiency. However, the steam parameters still remained in a subcritical pressure range (below 225 ata).

Table 3.1.1. Generation efficiency of coal-based power plants having subcritical steam cycle*

Unit rating (MW)	Steam Parameters	Plant heat rate (kCal/kWh)	Net generation efficiency (%)
30	65 ata/480°C, non-reheat	2,824	27.41
60/70	90 ata/535°C, non-reheat	2,588	29.91
100	90 ata/535°C, non-reheat	2,580	30.02
110/120	130 ata/537°C/537°C	2,330	33.22
210	150 ata/537°C/537°C	2,314	33.82
250/500	170 ata/537°C/537°C	2,288	34.58

*Considering boiler efficiency of 85% and auxiliary power consumption of 10% for units less than 210 MW, 9% for 210 MW, and 8% for 250/500 MW.
Source: Abbi 2003

CEA, while compiling the data for the performance of 500 MW power plants, has taken the average net efficiency as 33%. Thus the above data is slightly at variance with the CEA data. This may be due to the variation in boiler efficiency and the older turbines, which were slightly less efficient.

The technological growth, as given in table 3.1.1, has been possible through development of indigenous design and manufacturing capabilities for power plant equipment. A major role for this was played by a state-owned company—Bharat Heavy Electricals Limited (BHEL)—which has contributed to 79% of total installed capacity of coal-based thermal power plants in the country as of 2007–08.

3.2 Technology progress during 2007–12 period

The demand for installing additional power generation capacity during this period to meet the electricity requirements is approximately 42,480 MW of additional coal-based capacity.

Because of the requirement of capacity addition and the likely capacity that would actually materialize during the 11th Plan period, there is a need to mobilize around 42,480 MW of additional capacity. For this, the GOI will depend on large capacity addition by independent power producers (IPPs), for which the competitive bidding process has been adopted. At the same time, considerations of energy security are also likely to simultaneously lead to the promotion of clean coal technologies with higher efficiencies.

Thus, as a next step toward improving generation efficiency of coal-based power plants, supercritical steam parameters are being adopted for the steam cycle of future plants. These parameters are also being upgraded gradually, as can be seen from table 3.2.1.

Table 3.2.1. Generation efficiency* of coal-based power plants having a supercritical steam cycle**

Unit rating (MW)	Steam Parameters	Plant heat rate (kCal/kWh)	Net generation efficiency (%)
660 (Sipat)	246 ata/537°C/565°C	2,240	35.51
660 (North Karanpura)	246 ata/565°C/565°C	2,219	35.85
800 (UMPPs)	306 ata/598°C/598°C	2,174	36.59

*Projected by NTPC

**Considering boiler efficiency of 85% and auxiliary power consumption of 7.5%.

The first supercritical unit of 660 MW capacity is likely to be commissioned at National Thermal Power Corporation (NTPC) Sipat during the first quarter of 2009. Subsequently, nine more units of 660 MW each and one of 800 MW (ultrasupercritical, or USC) are expected to be commissioned until March 2012, as per details given in table 3.2.2.

Table 3.2.2. Supercritical projects expected to be commissioned during the 11th Five-Year Plan period (2007–12)

Plant name	Capacity (MW)
Sipat	3 x 660
Barh	3 x 660
North Karanpura	1 x 660
Sasan	2 x 660
Krishnapatnam	1 x 800
Total Capacity	6,740

The progress toward setting up supercritical power plants is taking place because of promotional financial incentives by GOI policies as well as financial benefits expected from the Clean Development Mechanism (CDM) under UNFCCC for adopting high-efficiency power generating systems.

Box 3.2.1. CDM in Indian Power Generation

The Sasan UMPP is an example of a high-efficiency power generating system that will be created with the help of financial incentives and benefits from the GOI and UNFCCC. Sasan Power Limited, subsidiary of Reliance Power Limited, is establishing a new 3,960 MW coal-based generation facility at Sasan, Madhya Pradesh, using supercritical technology. It has already submitted the project design document (PDD) to EB-UNFCCC for registering this as a CDM project. Financial additionality has been presented to justify the registration of the project as CDM activity. The PDD is at validation stage presently.

ACM0013, an approved consolidated baseline and monitoring methodology for new grid-connected fossil-fuel-fired power plants using a less GHG-intensive technology, was developed for such projects to be eligible for CDM benefits and hence make it an attractive option for the investors. According to the ACM0013 methodology, investment comparison analysis based on levelized cost of electricity production in INR/kWh as financial indicator would be used. The comparison in the project design document of the Sasan Project indicates that the levelized cost of electricity production for the project activity without CDM benefits is 1.08 INR/kWh, which is higher than the most economic alternative scenario—that is, power generation facility using coal with subcritical technology, in which case the levelized cost of electricity production is 1.04 INR/kWh. The upfront investment for the supercritical option is also higher than that for the subcritical technology.

It may be appreciated that for adopting supercritical steam cycle for power generation, major technological upgrades are required for both boilers and steam turbines. The boilers have to be designed as once-through circulation systems, as compared with subcritical boilers which are designed as drum-type systems. All the components/subsystems of boilers and steam turbines have to be designed for higher pressures and higher temperature applications. Further, higher temperature steam also requires processing special alloy-steels, which need different manufacturing processes. For this, the manufacturing facilities have to be built and the operating manpower trained suitably for manufacture as well as operation of different equipment/systems.

Major equipment such as boilers and steam turbines for the supercritical/USC plants ordered so far are likely to be imported. The country, however, cannot depend purely on imports for large-capacity additions. Indigenous design and manufacturing facilities are planned through technological collaborations (see box 3.2.2).

Box 3.2.2. Technological collaborations/Joint ventures for supercritical units

To date, the following technical collaborations/joint ventures are already in place for boilers and steam turbines:

Boilers
Joint Venture of MHI, Japan, and L&T, India
Technical collaboration of BHEL, India and Alstom, Germany

Steam turbines
Joint Venture of Toshiba, Japan, and JSW, India
Technical collaboration of BHEL, India and Siemens, Germany
Joint Venture of Bharat Forge, India, and Alstom, Germany

In addition to this, GOI has advised that only foreign companies that have a phased manufacturing program within the country will be eligible to offer quotes for future public sector projects. This is expected to lead to more foreign/Indian companies setting up design and manufacture of supercritical/USC power plants in India.

3.2.1 IGCC technology development

All approaches for further efficiency improvement or reduction of emissions of pollutants from coal-based power generation leads to thermodynamic cycles, including gas turbine in a topping cycle and a steam turbine in a bottoming cycle, which is the so-called combined cycle. However, gas turbines need clean fuel gas or liquid fuel. Therefore, use of coal for this cycle calls for its gasification to produce clean fuel gas (coal gas) before it is burned in the combustion chamber of the gas turbine. The integration of coal gasification and combined cycle power generation is called the IGCC system.

Coal can be gasified by reacting coal with air/steam or oxygen/steam; the former reaction produces low calorific value (CV) gas whereas the latter reaction produces medium CV gas. For combined cycle operation, it is economical to adopt pressurized gasification. The hot raw gas from the gasifier is cooled by generating steam through the heat recovery steam generator. This steam is integrated in the combined cycle with the steam produced from the heat recovery steam generator downstream of the gas turbine. Part of the steam produced is used in the gasifier.

Typically, IGCC efficiency is the product of efficiency of the gasifier (90% achievable) and the combined cycle efficiency (55% with contemporary gas turbines), giving a net value of 42% to 44% compared to 40% achievable through the USC steam cycle. This will proportionately reduce carbon dioxide (CO_2) emission. The sulfur oxide (SO_X) emission can be brought down to 40 to 115 mg/Nm^3 (depending on the coal gas cleaning process adopted) as the sulfur is removed in the gasification process itself. The nitrous oxide (NO_X) emission has also been reported to levels below 125 mg/Nm^3.

The Council for Scientific and Industrial Research, GOI, published a study in 1992 entitled "Feasibility Assessment of IGCC for Power Generation Technology for High Ash Coals." This study was conducted by Bechtel Corporation, San Francisco, with U.S. Agency for International Development (USAID) funding. The primary objective was to rank the four gasification processes (Shell, Texaco, Kellogg Rust Westinghouse [KRW], and indigenously developed moving bed) for IGCC plants in India. The

economics of these plants was to be established through conceptual design of IGCC plants based on each gasification process, in the capacity range of 500 to 600 MW. It was concluded that the KRW gasifier or similar fluidized bed gasification processes, such as U-gas, are most appropriate to use for the high-ash Indian coals.

A 100 MW IGCC demonstration plant with KRW gasifier was commissioned at Pinon Pine, North Dakota, USA, in 1998. It was operated for a short time, and the gasifier was shut down because of technical and commercial reasons. The U-gas technology for coal has not been scaled up beyond the pilot plant. Thus, there was no choice for India but to develop, on its own, technology applicable to its coal.

In 2005 and 2006, Nexant and National Energy Technology Laboratory, USA, conducted a study with assistance from USAID and NTPC, India, on IGCC technology selection for Indian coals. This study concluded that the gasifier judged to be most suitable and economical for high-ash Indian coals is pressurized fluidized bed U-gas gasifier, with enriched air of 30% oxygen concentration (by volume). The study recommended setting up a 100 MW IGCC plant with this gasifier and a GE 6FA gas turbine. It was learned during the discussions with officials of Ministry of Power, GOI, and USAID, New Delhi, that presently discussions are in progress between GOI and the U.S. government under the Indo-U.S. Energy Working Group, and a Technology Expert Group has been formed to identify a partner from the United States to work with NTPC for this demonstration plant.

In India, pioneering research and development (R&D) work has been done for development of coal-based IGCC by BHEL on a 6.2 MW_e (4 MW gas turbine and 2.5 MW steam turbine) pilot plant at Trichy, using a pressurized moving bed gasifier and a pressurized fluidized bed gasifier (PFBG), using high ash coals. On the basis of this work, design of a 125 MW IGCC demonstration plant with PFBG has been developed. The next step was to seek a site for semi-commercial demonstration plant of this size and to seek the funding requirements, especially the incremental cost, from GOI or international sources.

To assess the development work for the scaled-up design and to ascertain the need for government grants, the office of Principal Scientific Adviser to GOI set up an R&D committee in January 2003. The committee advised further research work on the 6.2 MW pilot plant. The committee's final report was issued in December 2005. It is recommended that incremental cost may be funded partly by the Planning Commission, GOI, as grant-in-aid for the semi-commercial demonstration plant. Based on these recommendations, BHEL and Andhra Pradesh Power Generation Corporation Limited (APGENCO) have agreed to set up a 125 MW plant at Vijaywada in Andhra Pradesh. The foundation stone for this plant was laid on July 1, 2008. It is understood through interactions with BHEL that the capacity of this plant has been raised to 180 MW, and a GE gas turbine Frame 9FA will be used for this project. This turbine has been chosen because GE has good experience operating this gas turbine on low-CV coal gas. This demonstration plant is expected to be commissioned in 2011.

3.2.2 Carbon capture and sequestration

This is a relatively new subject for India and also globally; it is at a basic R&D stage for identification of suitable sites for CO_2 sequestration. Most prospective sites are located on basalt rocks in the Deccan Volcanic Plateau. However, the science of storage in basalt formations is relatively undeveloped. This has also been pointed out by an IEA study published in 2007, titled "A regional assessment of the potential for CO_2 storage in the Indian subcontinent." This study also concluded that potential of storage in deep coal seams and oil and gas fields onshore is small, and considerable potential exists for storage in deep saline aquifers. However, all this needs to be explored further.

In view of the above, Department of Science and Technology, GOI, has initiated R&D work in a few research laboratories. It has also assigned a pilot study on "Geological CO_2 sequestration in basalt formations in Western India" to National Geographical Research Institute, Hyderabad.

Worldwide, 34 carbon capture and storage (CCS) projects are at various stages of implementation, but only five of these are on the commercial scale (IEA, 2008b) for enhanced oil recovery. The most important barrier to application of this technology for thermal power sector is high capital cost and a very heavy energy penalty in terms of auxiliary power consumption, leading to a high cost of power generation. From a developing country perspective, it becomes important to consider the implication of a very high tariff and also significantly higher investment.

Moreover, numerous uncertainties are associated with CCS; apart from the costs, an important issue is that the risks of leakage from underground storage are unknown. There are also fears about adverse impacts on groundwater tables, as well as increasing seismic risks.

A preliminary estimate in 2008 by United Kingdom-based consulting company Mott MacDonald for three UMPPs in India shows that a CO_2 abatement incentive of U.S. $35 to $42 per tonne (t) CO_2 would be required for CCS. Other estimates place the cost at above U.S. $60 per t CO_2. Even if CCS projects are registered as CDM projects, the revenues received from this CDM activity will be less when we consider the present price of certified emission reductions (CERs). As a result, the CCS is currently unviable and, under the present circumstances, it is felt that CCS may not play any role in CO_2 emission mitigation in the foreseeable future in India.

3.3 Technology forecast for 2012–32 period

The technologies basket for coal-based power generation in India for the period 2012–2032 would contain the following main technologies:

- Subcritical steam cycle
- Supercritical steam cycle
- USC steam cycle
- IGCC

As stated in section 3.2 above, good experience of operation of thermal plants with supercritical steam parameters is expected to be achieved by 2012. Indigenous capacity for design and manufacture of these plants would also be in place. Thus the period beyond 2012 is expected to see large-scale introduction of supercritical and USC plants. The 12th Plan (2012–2017) forecast for coal-based plants is as given in table 3.3.1.

Table 3.3.1. Supercritical/ultrasupercritical steam cycle plants during 2012–2017

Plant Name	State	Agency	Capacity (MW)
Jhajjar (Matanhail)	Haryana	IPP	2 x 660
UMP, Mundra	Gujarat	IPP	3 x 800
UMP, Krishnapatnam	Andhra Pradesh	IPP	5 x 800
UMP, TN	Tamil Nadu	IPP	5 x 800
UMP, Sasan	Madhya Pradesh	IPP	6 x 660
UMP, Tilaiya	Jharkhand	IPP	5 x 800
UMP, Orissa	Orissa	IPP	5 x 800
Barh II	Bihar	NTPC	2 x 660
Integrated Project, Daripalli	Orissa	NTPC	4 x 800
Integrated Project, Lara	Chattisgarh	NTPC	5 x 800
North Karanpura	Jharkhand	NTPC	2 x 660
Talwandi Sabo	Punjab	PSEB	3 x 660
Bara TPS	Uttar Pradesh	UPRVUNL	3 x 660
Obra Extn	Uttar Pradesh	UPRVUNL	2 x 800
Karchana	Uttar Pradesh	UPRVUNL	2 x 800
IFFCO Sarguja	Chattisgarh	CSEB	2 x 800
Bhaiyathan	Chattisgarh	CSEB	2 x 660
Koradi Extn	Maharashtra	MAHAGENCO	1 x 800
Koradi Replacement	Maharashtra	MAHAGENCO	1 x 800
Krishnapatnam	Andhra Pradesh	APGENCO	2 x 800
Supercritical units* (Total)			42,480
Subcritical Units (Total)			20,450
Total			62,930

* Supercritical included supercritical and ultrasupercritical units.

It may be seen from this table that 42,480 MW out of a total 62,930 MW (67.5%) capacity addition will be based on supercritical or USC technology. This shows a quantum shift to supercritical technology. The major contribution for these plants would come through private sector participation. It is assumed that CDM benefits under the Kyoto Protocol will be available to establish the techno-

economic viability of each plant. Thus, extension of the Kyoto Protocol beyond 2012 would be a major influencing factor for setting up these plants.

The operating experience of the 180 MW IGCC demonstration plant (see section 3.2.1) for about two years will also pave the way for setting up the first commercial IGCC plant of 400 to 600 MW capacity by 2017. This again would be subject to availability of incremental cost through national and international funding for clean coal technology.

Based on the technology growth scenario given in sections 3.1 to 3.3, the technology forecast for coal-based plants is as given in table 3.3.2. The detailed scenarios for technology penetration and its resulting impact on emissions have been presented in chapter 4 (section 4.2).

Table 3.3.2. Technology forecast for coal-based thermal power plants in India

Year 2007–12	Year 2012–17	Year 2017–22	Year 2022–27	Year 2027–32
+ Subcritical + Supercritical + USC + IGCC demo plant	+ Subcritical + Supercritical + USC + IGCC first commercial plant	+ Subcritical + Supercritical + USC + IGCC	+ Subcritical + Supercritical + USC + IGCC	+ Subcritical + Supercritical + USC + IGCC

3.3.1 Barriers to technology growth

The above forecast brings out that during 2007–12, the supercritical steam cycle technology will start functioning in India; there is a possibility of one or two USC plants also. In addition, semi-commercial demonstration of IGCC technology will take place. This will pave the way for penetration of these technologies at a faster pace during the next 20-year period, 2012–32. This will be true particularly for supercritical and USC, with IGCC moving forward slowly. The main barriers to this growth will primarily be the incremental costs of these power plants as compared with subcritical systems. Presently, revenues from CDM are included in the techno-economics of the new plants. If this does not happen beyond 2012, the growth of technology penetration may slow. The penetration of IGCC technology would depend solely on the successful operation of the semi-commercial demonstration plant. Besides the efficiency improvement, it has to show the reliability and availability of the plant with PLF of 85% and above. If demonstration of these parameters is delayed, the penetration of the technology will also be delayed. Second, the availability of incremental costs through support from international climate change mitigation funds would also be critical.

The import of coal for power generation is also increasing gradually. It was 10.7 million tonnes in 2007–08 and it is expected to be 40 million tonnes in 2012. This trend is expected to continue in years to come. This gives rise to the possibility of setting up more IGCC plants during the period 2012–32, based on the gasification technology that has been demonstrated for high-quality coal in the United States and Europe.

3.4 Cleaner coal technology implementation

It is expected that only two new technologies—supercritical steam cycle and IGCC—would be deployed commercially for coal-based thermal power generation in India, until 2032.

The process for transfer of supercritical technology to India through technology transfer agreements (TTAs) and joint ventures (JVs) has already started. This will help in reduction of project time cycle from concept to commissioning and cost reduction in years to come. However, at present the capital cost of these plants is high when compared with subcritical technology. The techno-economics, with improved efficiency of supercritical cycle, is justified by the CDM benefits that are included in each project. Thus, the future of the Kyoto Protocol beyond 2012 may become an important barrier for widespread deployment of this technology. Further technology for subsystems of this technology, such as high-pressure boiler feed water pumps and control systems, would be required. Technology transfer through TTAs for these can be worked out. Intellectual property rights (IPR) can be protected through suitably drafting the TTAs. GOI is committed to protecting IPR.

PFBG technology is the most suitable gasification technology for high-ash Indian coals for deployment of IGCC in coal-based power plants. Worldwide, there are no commercial or semi-commercial plants. Thus, for any technology proposed, a semi-commercial demonstration plant will have to be set up to prove its viability and reliability. According to data collected from operation of such a plant, commercial plants can be designed for further diffusion of the technology. The main issues to be addressed are cost, guaranteed performance, and guaranteed availability of the plant (to be guaranteed by the turnkey contractor). Besides technology, national and international funding will have to be sought for the demonstration plant.

Various studies worldwide show that the capital cost and cost of electricity generation per kWh for commercial plants would be higher for initial plants, as compared to the Pulverized Coal (PC) combustion technology presently in vogue. Thus future IGCC plants would require incremental cost funding until the technology becomes mature and cost competitive.

Technology transfer of the following subsystems is needed for IGCC:

- PFBG for high-ash India coals
- Entrained bed gasification for low-ash high-CV imported coals
- Hot gas clean-up system
- Pressurized coal feeding system
- Coal drying system
- Denitrification (DeNOx) and desulfurization (DeSOx) systems for coal gas
- Gas turbines for low-CV coal gas
- Design and engineering of integrated system for IGCC plant
- Control systems for IGCC plant

There are no policy barriers for technology transfer for any of the above systems. IPR can be protected through TTA.

The above sections make it amply clear that IGCC technology development/transfer and deployment would require funding support for the incremental costs. This can be made possible through policy interventions nationally (incentives in the form of soft loans, subsidies, tax exemptions,

etc.) and internationally (financial support for incremental costs and technology transfer from developed to developing countries at affordable cost, under climate change negotiations through UNFCCC) for large-scale deployment of IGCC.

Chapter 4

GHG emissions scenario (2007–2031)

In this chapter, efforts have been made to quantify the emissions from existing coal-based thermal power plants during 2006–07 (April 2006 to March 2007), based on data published by CEA, Ministry of Power, GOI. The future scenario has been developed based on the technology forecast (chapter 3) and the additional coal-based thermal power capacity envisaged (chapter 2), until 2031–32.

4.1 Emission factors and total emissions

The emissions from all the coal-based power plants and the net electricity generation have been compiled in table 4.1.1 for the year 2006–07 (http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm). All these plants are based on subcritical steam cycle technology. The total electricity generation from all the plants is 394,046 GWh, giving rise to absolute emission of 425,935,577 t CO_2. Thus the overall average emission factor of existing coal-based subcritical power generation is 1.0809 t CO_2/MWh. The average PLF of all these plants is 77.03%.

Table 4.1.1. CO_2 emissions from coal-based power plants in India in 2006–07

Power Plant	Net generation (GWh)	Absolute Emissions (t CO_2)
Patratu	526	971,969
Barauni	27	62,108
Kahalgaon	6,031	6,072,998
Tenughat	1,775	2,389
Jojobera	2,443	2,663,902
Chanderpur	1,876	2,562,831
Durgapur	1,827	2,474,807
Bokaro B	2,957	4,117,232
Mejia	5,610	5,984,607
Talcher	3,189	3,909,082
IB Valley	2,976	3,047,575
Talcher STP	22,356	21,238,394
Bandel	1,380	1,845,340
Santaldih	1,245	1,986,454
Kolaghat	6,794	9,851,395

Bakreshwar	4,470	5,549,057
D.P.L.	1,594	2,316,074
New Cossipore	439	895,270
Titagarh	1,676	2,056,613
Southern Repl.	919	1,100,299
Budge Budge	4,015	3,993,139
Farakka STP	10,638	10,479,538
Badarpur	4,879	5,534,896
I P Station	805	1,364,390
Rajghat	558	769,221
Faridabad Extn.	523	1,005,556
Panipat	8,963	10,536,475
GNDTP (Bathinda)	1,966	2,527,157
GNDTP (Lehra Mohabat)	3,140	3,185,309
Ropar	8,952	9,967,825
Kota	7,398	8,061,323
Suratgarh	9,270	9,553,928
Obra-A	4,646	6,765,032
Panki	804	1,190,519
Harduaganj-B	644	989,669
Paricha	1,906	3,045,717
Anpara	11,288	11,622,726
Singarauli STP	13,627	13,366,504
Rihand	15,055	14,394,401
Unchahar	6,942	6,918,063
Dadri (NCTP)	6,517	6,407,235
Tanda	3,114	3,661,485
Ukai	4,383	5,070,801
Gandhinagar	4,276	5,354,254
Wanakbori	10,050	10,687,365
Sikka Rep.	1,407	1,819,937
Torr P S	2,965	3,745,552

Satpura	6,687	8,977,281
Kobra East	2,978	3,487,324
Kobra West	5,387	6,266,451
Amarkantak	1,100	1,822,273
Sanjay Gandhi	4,874	6,183,373
Korba STPS	15,472	14,839,026
Vindyachal	18,838	18,340,418
Nasik	5,936	7,610,198
Koradi	6,123	7,704,177
Khaparkheda	5,989	6,508,214
Paras	382	525,693
Bhusawal	2,885	3,201,514
Parli	4,142	4,637,269
Chanderpur	12,094	12,340,356
Trombay Coal	3,828	3,788,003
Kothagudam	4,361	4,955,127
Kothagudam New	3,337	3,299,153
Vijaywada	9,074	8,954,414
Ramagundam	298	346,321
Rayalseema	2,961	2,908,440
Ramagundam STPS	18,989	18,271,968
Simhadri	7,620	7,204,365
Raichur	10,540	11,177,703
Torangalu IMP	1,913	1,389,202
Ennore	1,230	1,744,354
Tuticorin	7,446	7,647,325
Mettur	6,253	6,519,863
North Chennai	4,468	4,559,359
Total	**394,046**	**425,935,577**

Similarly, the emissions from existing coal-based 500 MW units and the net electricity generation have been compiled in table 4.1.2. Only two units have been excluded in this list, as the data

for them were not available. From this table, it is found that total power generation is 61,372 GWh, while total emissions are 58,771,990 t CO_2. This gives an emission factor of 0.9576 t CO_2/MWh.

Table 4.1.2. CO_2 emissions from 500 MW coal-based power plants in India in 2006–07

Power Plant	Net generation (GWh)	Absolute Emissions (t CO_2)
Talcher STPP (6 x 500 MW)	22,356	21,238,394
Rihand (4 x 500 MW)	15,055	14,394,401
Vindyachal (4 x 500 MW)	9,289	9,044,126
Trombay Coal (1 x 500 MW)	3,828	3,788,003
Ramagundam (1 x 500 MW)	3,224	3,102,701
Simhadri (2 x 500 MW)	7,620	7,204,365
Total	**61,372**	**58,771,990**

Note: Only those 500 MW units, for which data are available separately, have been taken.
To calculate emissions, the average net generation efficiency of the existing 500 MW units has been assumed as 33%.[5]

Taking the net generation efficiencies of supercritical and USC plants as given in table 3.2.1, the emission factors for these plants are as given in table 4.1.3. For IGCC technology, a conservative figure of 42% gross generation efficiency and 8% auxiliary power consumption has been assumed. This will give net generation efficiency of 38.64%.

Table 4.1.3. Emission factors for supercritical and ultrasupercritical plants

Technology	Ratio of net generation efficiency (compared to 500 MW unit)	Emission factor (t CO_2/MWh)
500 MW subcritical	1.0	0.9576
660 MW supercritical*	0.9205	0.8815
800 MW ultrasupercritical	0.9019	0.8636
IGCC	0.8540	0.8178

*Taking North Karanpura as base case for future

4.2 Emission reductions possible through technological interventions

Taking into account the projected growth of coal-based thermal power in India (table 2.3.2), three scenarios have been developed with different degrees of technology penetration specific to the coal-based power sector to better understand the impact of cleaner coal technologies on the CO_2

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

emissions of the thermal (coal) power sector. These scenarios consider the various mixes of subcritical technology, supercritical technology, USC technology, and IGCC technology.

The BAU scenario is based on subcritical technology, with just one improvement that the efficiency of future plants will be at least equal to present 250/500 MW plants. The technology upgrade scenario TU-1 in table 4.2.1 is based on the prediction of the efforts being made presently to introduce supercritical, USC, and IGCC technology for future power plants during the 11th, 12th, and 13th Five-Year Plan periods. In TU-2, as given in table 4.2.2, a more optimistic scenario for the introduction of these technologies has been considered, to see its quantitative impact on GHG emission reductions.

Considering the estimated coal-based generation capacity as per table 2.3.2 and the technological growth as given in table 3.3.2, the technology-wise capacity addition during the period 2007–32 is predicted to be as given in table 4.2.1.

Table 4.2.1. Scenario for technology-wise coal-based generation capacity addition during 2007–32, with TU-1

Technology	2007–12	2012–17	2017–22	2022–27	2027–32
Subcritical	35,740 (84%)	19,850 (31.5%)	12,920 (23%)	15,800 (20%)	10,800 (10%)
Supercritical	5,940 (14%)	13,200 (21%)	16,500(29%)	23,100 (29%)	33,000 (30%)
USC	800 (2%)	29,280 (46.5%)	25,280 (45%)	37,100 (47%)	55,200 (51%)
IGCC	Demo plant	600 (1%)	1,800 (3%)	3,000 (4%)	9,000 (9%)
Total	42,480	62,930	56,500	79,000	108,000

Note: All figures are in MW (% of the capacity addition).

In light of the scenario given in table 4.2.1, the emission factors as per table 4.1.2, and the generation capacity and PLF built up as given in table 2.3.2, the emissions during different years (end of each Five-Year Plan period) can be estimated.

Taking the abovementioned scenario for capacity addition (hereafter referred to as Technology Upgradation–1 (TU-1)) as a reference, two alternative scenarios have been developed. The first scenario takes into account a low cost of investment as per current investment costs for setting up thermal power generation. As a result, all future capacities to be added would be in terms of subcritical units only. For all new additions, the emission factor assumed is that for 500 MW units. The second scenario involves an aggressive pace of supercritical and USC technologies along with IGCC plants. Both these scenarios have been tabulated below in table 4.2.2.

Table 4.2.2. Capacity addition in the alternate scenarios

Technology	2007–12	2012–17	2017–22	2022–27	2027–32
ASCU					
Subcritical	42,480 (100%)	62,930 (100%)	56,500 (100%)	79,000 (100%)	108,000 (100%)
Supercritical	0	0	0	0	0
USC	0	0	0	0	0
IGCC	0	0	0	0	0
Total	42,480	62,930	56,500	79,000	108,000
TU–2					
Subcritical	33,760 (80%)	14,630 (23%)	5,560 (10%)	2,460 (3%)	700 (0.6%)
Supercritical	7,920 (18%)	16,500 (26%)	19,140 (34%)	25,740 (33%)	36,300 (34%)
USC	800 (2%)	31,200 (50%)	28,800 (51%)	44,800 (57%)	60,800 (56%)
IGCC	0	600 (1%)	3,000 (5%)	6,000 (7%)	10,200 (9.4%)
Total	42,480	62,930	56,500	79,000	108,000

The total CO_2 emissions in the fifth year of each plan period for each of these scenarios has been calculated (table 4.2.3) and depicted in figure 4.2.1. Also, the total absolute emissions that will result from each of the scenarios have been plotted in figure 4.2.2a; the cumulative emissions up to the end of each plan period have been plotted in figure 4.2.2 b. It can be seen that the emission reductions that can be achieved by the TU-1 and TU-2 scenarios, vis-à-vis the "All Subcritical Units Only" (ASCU) scenario, is quite significant. The results have been plotted in figure 4.2.3. The cumulative emission reduction possible during each Five-Year Plan period is plotted in figure 4.2.4. From this figure, we can see that the cumulative emission reduction possible up to the 2032 horizon by TU-1 is 4.83 billion t CO_2 and, by TU-2, is 5.17 billion t CO_2.

Table 4.2.3. Emission calculations for different scenarios

Scenarios	2006–07	2007–12	2012–17	2017–22	2022–27	2027–32
Total emissions in the last year of each Plan period (billion tonnes) – Figure 4.2.1						
ASCU	0.49	0.82	1.31	1.76	2.40	3.31
TU-1	0.49	0.78	1.19	1.56	2.08	2.83
TU-2	0.49	0.78	1.18	1.55	2.06	2.80
Absolute emissions cumulated for each Plan period – Figure 4.2.2a						
ASCU	0.49	3.37	5.25	7.33	9.82	13.46
TU-1	0.49	3.36	5.15	7.09	9.40	12.75
TU-2	0.49	3.34	5.14	7.05	9.33	12.63
Cumulative emissions until end of each Plan period – Figure 4.2.2b						
ASCU	0.49	3.3727	8.6252	15.9503	25.7733	39.2323
TU-1	0.49	3.3618	8.5151	15.6025	25.0071	37.7563
TU-2	0.49	3.3443	8.4832	15.5351	24.8647	37.4964
Emission reduction possible through different scenarios in the last year of each Plan period – Figure 4.2.3						
TU-1	0.00	0.04	0.12	0.20	0.31	0.48
TU-2	0.00	0.04	0.13	0.21	0.33	0.51
Cumulative emission reduction until end of Plan period – Figure 4.2.4						
TU-1	0.00	0.12	0.56	1.41	2.75	4.83
TU-2	0.00	0.12	0.58	1.50	2.97	5.17

The above emissions will, however, depend on the projected additional plants and technology upgrades in each Plan period. In the past, India has not been able to achieve the capacity addition targets as per the Five-Year Plans. If the same happens for the future Plans also, the absolute emissions will also be reduced accordingly.

Figure 4.2.1. Total emissions of CO_2 in the last year of each Plan period (in billion tonnes)

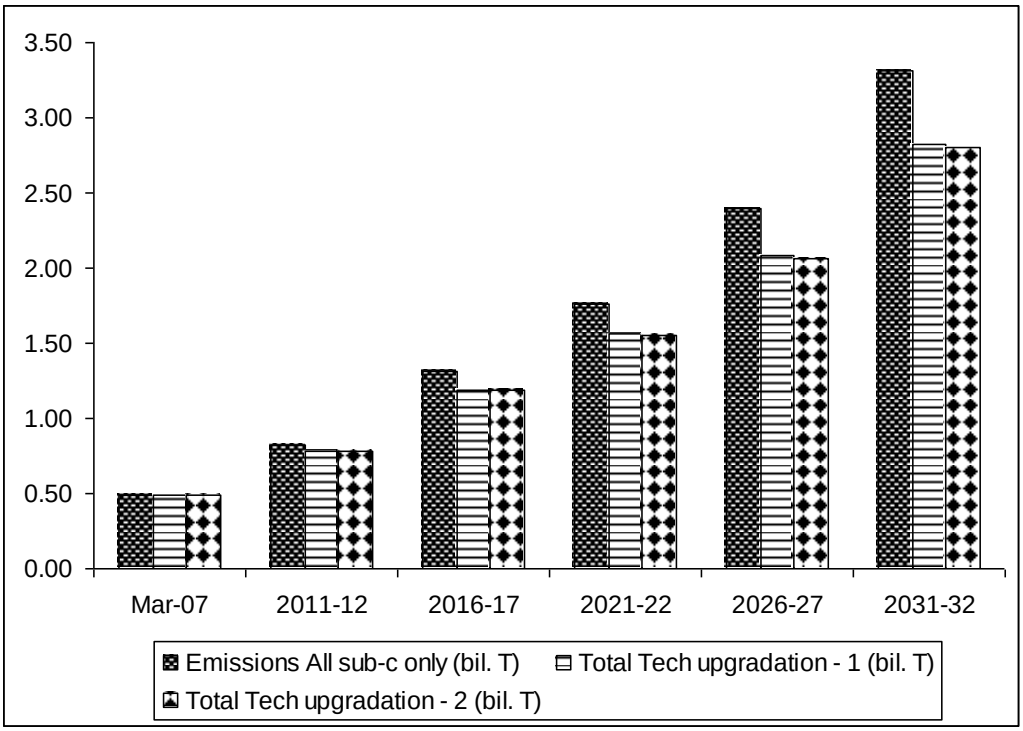


Figure 4.2.2a. Absolute emissions (in billion tonnes) cumulated for each plan period

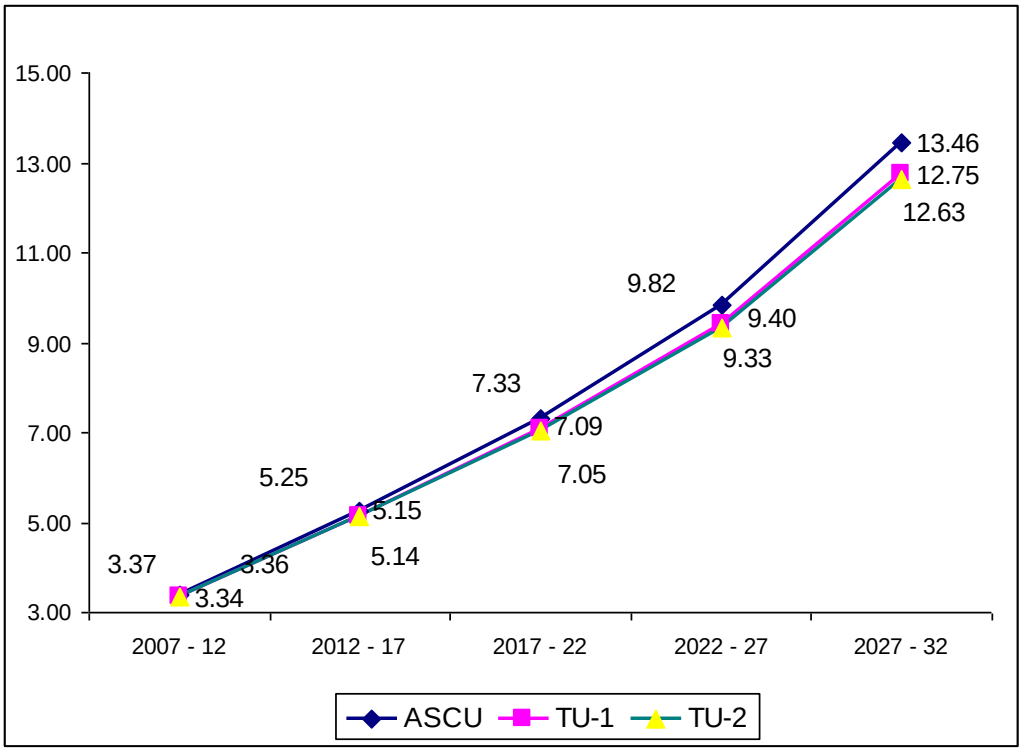


Figure 4.2.2b. Cumulative emissions until end of each Plan period under different technology scenarios.

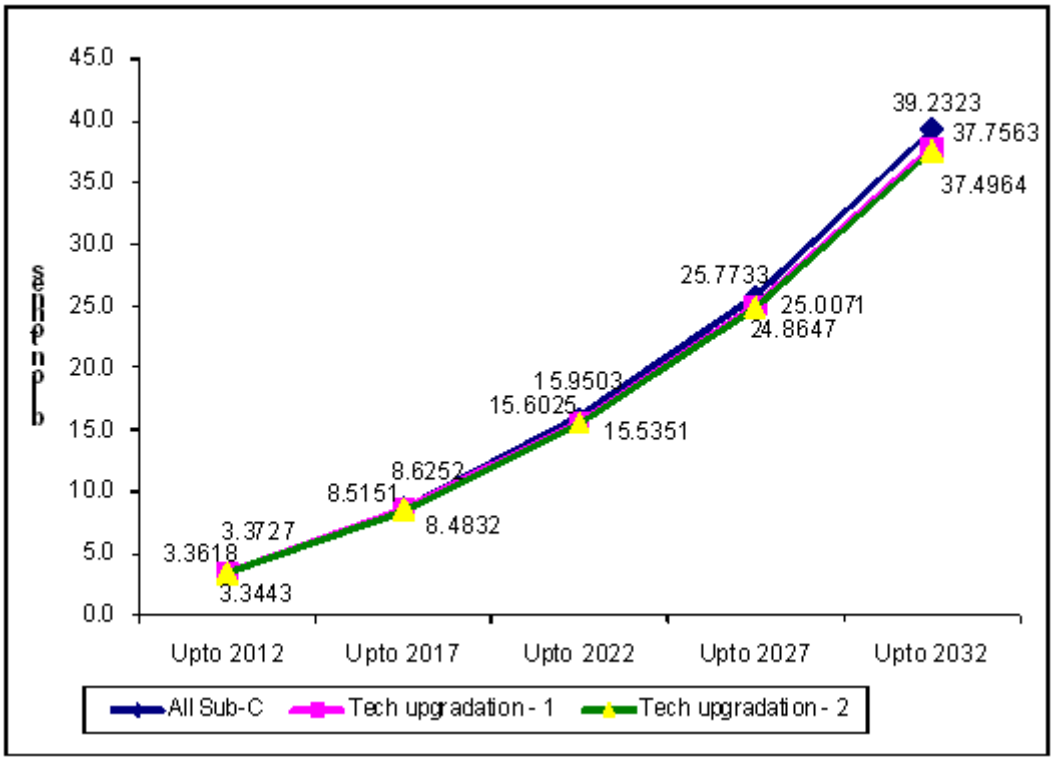


Figure 4.2.3. Emission reduction in the last year of each Plan period (in billion tonnes)

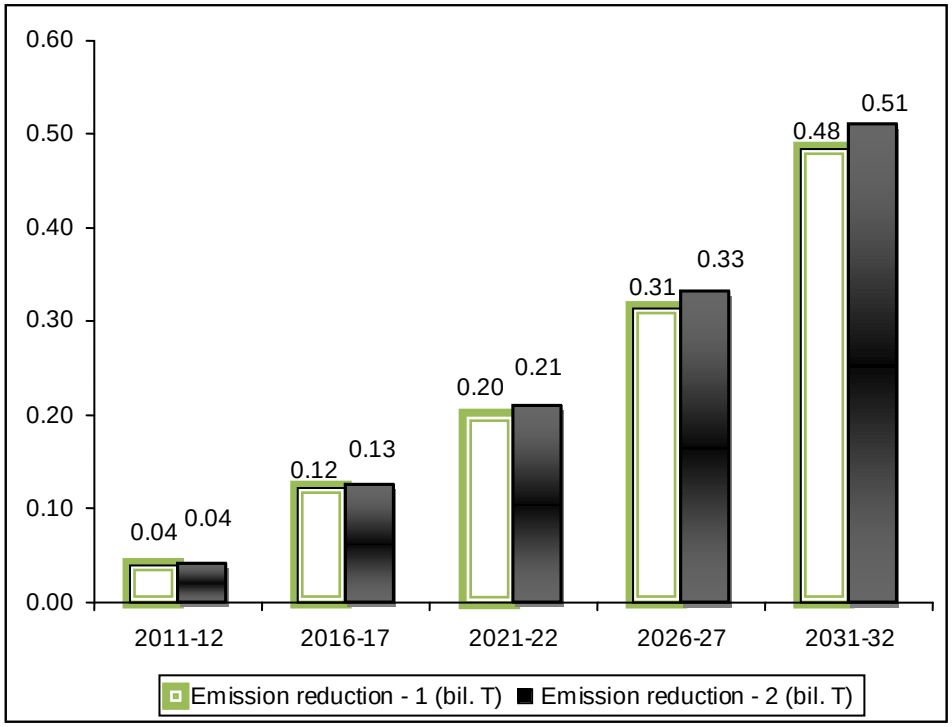
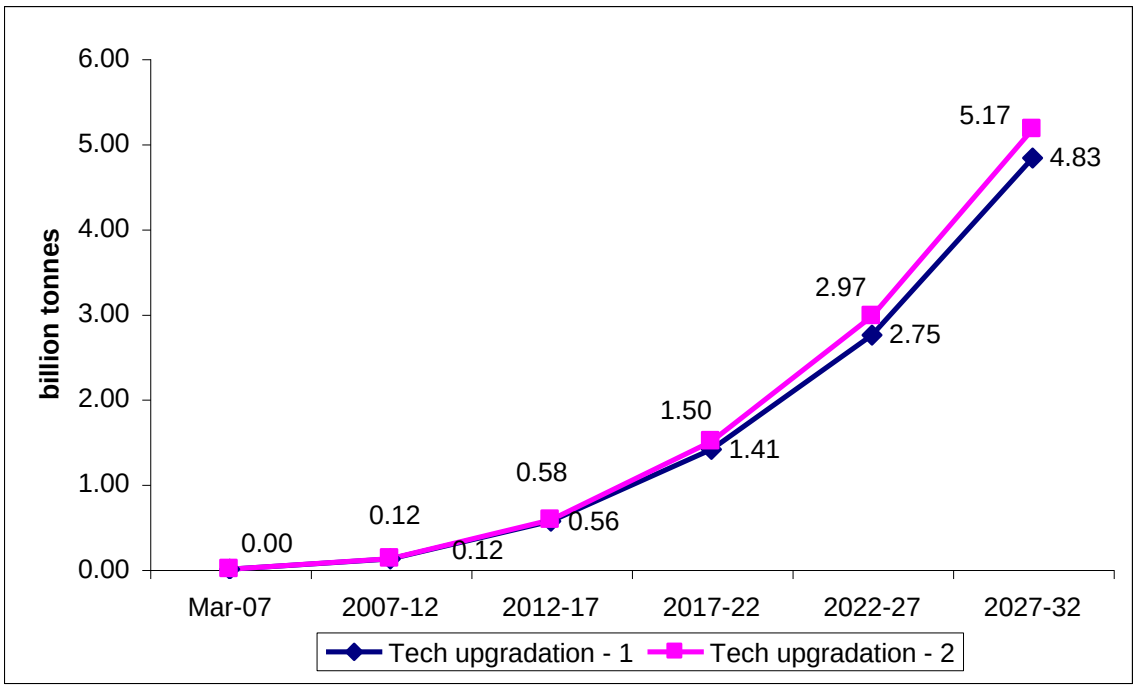


Figure 4.2.4. Cumulative emission reduction possible (in billion tonnes) in each technology scenario



The analysis of the data on estimated coal-based power generation capacity from 2007 to 2032 (table 2.3.2), the corresponding growth of GHG emissions (table 4.2.3 and figures 4.2.1, 4.2.2a, and 4.2.2b), and emission reduction potential (table 4.2.3 and figures 4.2.3 and 4.2.4) shows that

- The coal-based power generation capacity is estimated to grow from 67,596 MW (March 2007) to 416,505 MW (March 2032), to meet the energy needs of the country for 8% GDP growth.
- With the BAU technology scenario, the annual emissions will rise from 0.49 (year 2006–07) to 3.31 (year 2031–32) billion tonnes.
- With technology upgradation TU-1 as being planned presently, the annual emissions will rise from 0.49 (year 2006–07) to 2.83 (year 2031–32) billion tonnes. This shows a reduction of 0.48 billion tonnes per annum in 2031–32 as compared to the ASCU scenario.
- With technology upgradation TU-2 as being planned presently, the annual emissions will rise from 0.49 (year 2006–07) to 2.80 (year 2031–32) billion tonnes. This shows a reduction of 0.51 billion tonnes per annum by 2032. This scenario corresponds to only 0.6% capacity addition through subcritical technology during 2027–32; the balance, 99.4%, is through supercritical, USC, and IGCC technologies. This is a scenario of almost 100% technology upgradation from the present level by 2032.
- CCS technology is not expected to play any role in CO_2 emission mitigation in the foreseeable future in India, as explained in section 3.2.2.
- It can thus be seen that any further reduction in GHG emissions is possible only through substitution of some of the future coal-based capacity additions with nuclear- and

renewable-energy-based power generation. However, it should be noted that substitution of coal-based plants (say, x MW) with renewable energy (wind and solar) power generation would require approximately four to five times (4 to 5x MW) capacity addition to produce the same amount of electricity (MWh). Compared to coal-based plants, the capital cost (per MW) of renewable-energy-based power plants is very high. Correspondingly, these two factors will greatly increase the country's requirement for incremental funds (as addressed in section 5.1 for advanced coal-based power generation technologies).

Chapter 5

Funding requirement and financial mechanisms

5.1 Incremental costs for using efficient coal generation technologies

The technology upgrade as proposed in table 3.3.2 for coal-based thermal power generation will require additional upfront funds, apart from the need to gear up for indigenous design and manufacturing facilities. The investment per MW of installed capacity for different technologies is provided in table 5.1.1.

Table 5.1.1. Investment per MW for new coal-based power plants with different technologies (2006–07 costs; assuming no escalation of costs)

Technology	Investment (INR million/MW)
Subcritical steam cycle	40.0
Supercritical steam cycle	51.5
Ultrasupercritical steam cycle	55.8
IGCC	63.7

Note: U.S. $1 = 50 INR

Data on costs are not easily available in published documents for existing or new technologies, and these figures have been considered based on discussions with various experts. Any cost reductions during technology dispersion and indigenization of manufacture and capacity buildup has also not been considered.

Considering the technology-wise capacity additions (TU-1 and TU-2) as projected in tables 4.2.1 and 4.2.2 and the investment per MW of installed capacity as given in table 5.1.1, the incremental investment requirement for the coal-based power sector vis-à-vis the ASCU scenario has been estimated and tabulated in table 5.1.2. The resultant cumulative incremental investment required for each of the scenarios is given in table 5.1.3. The graphical representation of these cost figures has been provided in figures 5.1.1 and 5.1.2.

Table 5.1.2. Incremental investments (U.S.$ billion) required during each Plan period for different technology scenarios up to 2032

	2007–12	2012–17	2017–2022	2022–2027	2027–2032
TU-1	0.73	12.57	12.64	18.46	29.30
TU-2	2.07	13.94	14.93	22.92	32.40

Figure 5.1.1. Incremental investments (US$ billion) required during each Plan period.

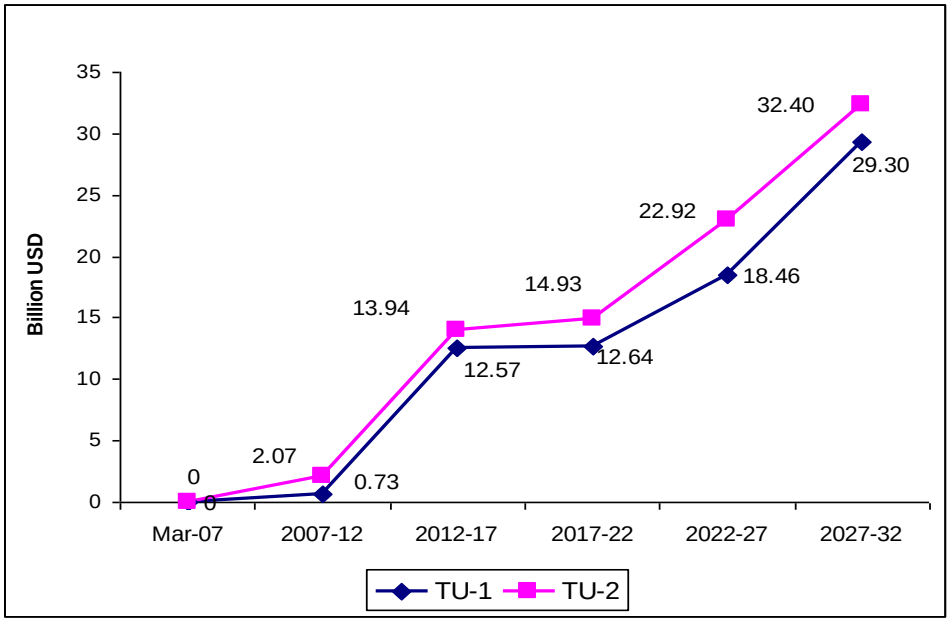
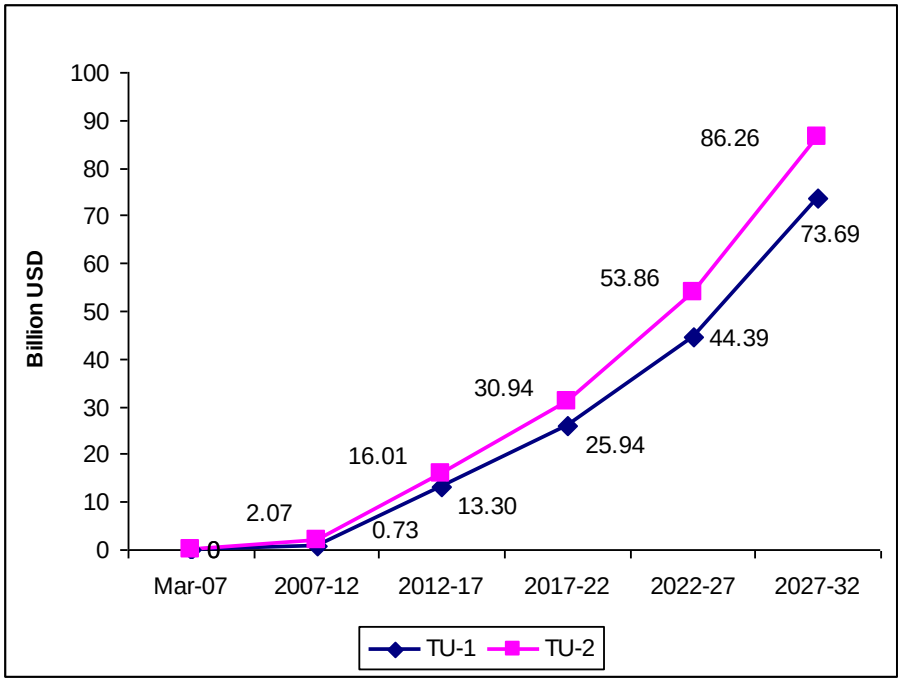


Table 5.1.3. Cumulative incremental investments (US$ billion) required for different technology scenarios

	Up to 2011–12	Up to 2016–17	Up to 2021–22	Up to 2026–27	Up to 2031–32
TU-1	0.73	13.30	25.94	44.39	73.69
TU-2	2.07	16.01	30.94	53.86	86.26

Figure 5.1.2. Cumulative investments (US$ billion) required for different technology scenarios



From the above, it is clear that the capital investments required by India for the coal-based thermal power sector are considerably high and mobilization of this investment is important to meet the energy needs that would be required to achieve the government's planned GDP growth. While it is expected that the country will mobilize funds for subcritical technology-based power plants (as projected in the ASCU scenario), because the infrastructure for design and manufacture exists in the country and it is the least costly option, technology upgrades would be possible only if the incremental costs are provided as nonrepayable financial support under the Convention. Even if these funds are provided as soft loans, the interest will add to the electricity tariff, which a developing country like India may not be able to afford.

5.2 Resources under the 11th Five-Year Plan of Government of India

The Working Group on Power has outlined the estimates for funding required for the 11th Plan[6] and their possible sources. The figures from the report indicate that most of the funds currently come from domestic sources such as banks and insurance companies. The proportion of funds being secured from international sources is comparatively smaller. The three potential sources of foreign funds are external commercial borrowings (ECBs), multilateral/bilateral funds, and foreign direct investment (FDI). The report notes that the volume of FDI in this sector is expected to be in the range of U.S.$360 million per annum. In addition, it has been assumed that the World Bank and Asian Development Bank each will fund U.S.$600 million per annum. It is also assumed that funding through export credit agencies (ECAs) and ECBs will be U.S.$2,500 million per year during the Plan period.

[6] It should be noted that the total funding requirements given by the document pertain to the requirements for generation, transmission, and distribution as well as that for renovation and maintenance, and so on.

Table 5.2.1. Estimated Funding for 11th Plan (INR Billion)

	Description	State	Central	Private	Total
	Funds required	5,142	2,994	2,180	10,316
A)	Equity Required (D/E - 70:30)	1,543	898	654	3,095
B)	Equity Available				
1	- Promoters including FDI for IPPs	-		255	255
	- Promoters including FDI for NCES and Captive	-		279	279
	- Merchant Power Plant			120	120
2	Internal Resources	-	629		629
3	Govt. Support				
3.1	State Govt.				
3.2	Central Govt.	-			
C)	**Total Equity Available**		**629**	**654**	**1,283**
D)	**Additional Equity to be arranged (A–C)**	**1,543**	**269**		**1,811**
E)	**Debt Required (D/E - 70:30)**	**3,599**	**2,096**	**1,526**	**7,221**
F)	Debt Available				
1.1	Direct Market Borrowing	100	150		250
1.2	Banks and AIFIs	372	584	106	1062
1.3	PFC	650	81	81	812
1.4	REC	473	59	59	592
1.5	IIFCL	-	60	90	150
2.1	Multilateral/Bilateral Credits	55	193	28	276
2.2	ECA/ECB/Syndicated Loan etc.	-	460	115	575
G)	**Total Debt Available**	**1,650**	**1,588**	**479**	**3717**
H)	**Additional Debt to be arranged (E–G)**	**1,949**	**508**	**1,047**	**3,505**
I)	**Additional Equity & Debt required (D+H)**	**3,492**	**777**	**1,047**	**5,316**
J)	**Total Available of Debt and Equity**	**1,650**	**2,217**	**1,133**	**5,000**
K)	Funding by Special Schemes				
1	APDRP	400			400
2	RGGVY	400			400
L)	**Total shortfall to be arranged (I–K)**	**2692**	**777**	**1047**	**4516**

Source: Planning Commission, 2007

As given in the above table, ECB would be the largest foreign source of funds. ECB in India for investment in infrastructure sector falls under the automatic route, that is, it does not require Reserve Bank of India/government approval.

The report of the Working Group on Power for the 11th Five-Year Plan notes that funding of projects from multilateral sources has also led to problems in the past as a result of

(a) Significant emphasis on environment and social issues with added costs of audits and certifications, and

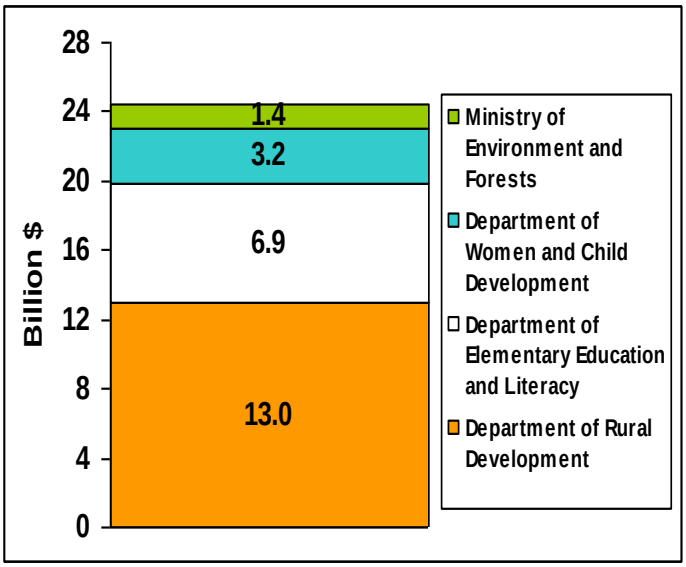
(b) Comparatively lengthy and time-consuming appraisal and due diligence exercise, conducted by multilateral agencies (Planning Commission, 2007)

5.3 Concerns related to trade-offs in financing India's development and energy technology needs

Though several energy-efficient policy and technological options available to India may be attractive in the long run, the large developmental needs of the Indian economy have to be borne in mind while considering the ability to undertake large investments for setting up new capacities.

The large levels of government expenditure that would be required to maintain the economic growth as planned and to provide for infrastructure and services that improve the HDI across all sections of society impose constraints on government spending directed purely at improving efficiencies. Moreover, apart from the risk perceived with the adoption of efficient technologies in the initial stages of their commercial use, the upfront incremental investment costs of most efficient technologies act as an additional barrier to investments that could be forthcoming from the private sector. Figure 5.3.1 shows the funds currently available as development outlays from different ministries. A comparison of these funds with those required for the movement toward clean coal technologies (table 5.1.2) clearly highlights the sacrifices in the development trajectory that may have to be made for the transformation to clean coal generation.

Figure 5.3.1. Select development outlays of 10th Five-Year Plan



Source: GOI, 2006

5.4 Financial Mechanisms for funding incremental costs

The following sections discuss the existing mechanisms for financing the incremental costs outlined above. Both the financial flows under the Convention and other sources of finance outside the UNFCCC have been discussed. The need for incremental funds for Indian coal-based power sector for cleaner technologies introduction with regard to the capacity of these funding mechanisms has also been discussed.

5.4.1 Clean Development Mechanism

The CDM is one of the flexible mechanisms created under the Kyoto Protocol. It has the dual objective of helping developing countries achieve sustainable development and helping developed countries achieve compliance with quantified emission reduction commitments.

In India, many industries have benefited from the growth of the carbon market trading CERs under this mechanism. The chemical and iron and steel industries have been the biggest beneficiaries. Energy-efficiency projects have come up in a large number across various industries. Though they are comparatively small in size, they offer huge potential.

For coal-based power generation projects, in September 2007 the UNFCCC decided to allow projects based on efficient technologies to participate in the CDM. It allows only power plants that supply electricity to a grid and that operate in countries where more than half the power is generated by coal-based plants. Only those thermal power plants that use clean and efficient technologies are eligible to earn credits. This was approved on the basis of documents prepared by Perspectives Climate Change GmbH, Hamburg, Germany, for a thermal power project promoted by NTPC, India, for the North Karanpura Greenfield supercritical coal-fired power project. The approved consolidated methodology (ACM) was named ACM0013 and was the result of combining the above-mentioned methodology with

the one proposed by Tsinghua University of China for Huaneng Yuhuan, the Ultrasupercritical Coal-fired Power Project. However, CDM EB has introduced a sunset clause that will limit the application of the methodology to 15% of the power generation in a country.

India has made effective use of the mechanism for such projects. Up to now, three projects have been submitted from India to the Executive Board for consideration of carbon credits and four have been submitted by China. Table 5.4.1.1 shows the project and the potential carbon credits expected from these projects until 2012. At present all are at the validation stage and no project to date has achieved registration from this sector.

Table 5.4.1.1. CDM projects in coal-based power generation

Title	**Host Country**	**Stage**	**2012 kt CO_2**	**Type**
Zhejiang Guodian Beilun Ultrasupercritical Power Project	China	At Validation	1,850	EE Supply side
Shanghai Waigaoqiao coal-fired power project using a less GHG intensive technology	China	At Validation	1,806	EE Supply side
Jiangsu Guodian Taizhou Ultrasupercritical Power Project	China	At Validation	2,424	EE Supply side
Zhejiang Guohua Ninghai Ultrasupercritical Power Project	China	At Validation	870	EE Supply side
GHG emission reductions through grid-connected high-efficiency power generation	India	At Validation	4,482	EE Supply side
Grid-connected energy-efficient power generation	India	At Validation	3,744	EE Supply side
GHG emission reductions through supercritical technology – Sasan Power Ltd.	India	At Validation	0	EE Supply side

Source: Capacity Development for the CDM 2009

CDM benefits have enhanced financial returns from these projects and thus play an important role as one of the key enablers in adopting these technologies. By increasing financial viability, the mechanism has also helped these projects better access capital markets for fund-raising. India's largest power production company, NTPC, a public sector enterprise, is setting up four power plants, all 660

MW or above, using supercritical technology. Section 3.2 has already outlined how the usage of CDM benefits would augment the financial attractiveness of a power generation project for investors. However, it would not be sufficient to cover the entire incremental cost.

The necessity of CDM revenue support for supercritical thermal power projects has also been brought out by other studies mentioned in Annex 1.

The uncertainty of carbon markets after 2012 is a concern for all these projects. At present, the projects are viable only with the support of CDM benefits, and the success of these plants will depend on them substantially. Therefore, it is imperative that CDM is continued to ensure the implementation and success of these projects. Expanding it to a programmatic approach (instead of 15% limit of power plant capacity) for the sector will help yield good results by reducing cost and facilitating indigenous production.

5.4.2 Global Environment Facility

The Parties to the UNFCCC assigned operation of the financial mechanism to the Global Environment Facility (GEF) on an ongoing basis, subject to review every four years. The financial mechanism is accountable to the Conference of Parties under the UNFCCC, which decides on its climate change policies, program priorities, and eligibility criteria for funding, based on advice from the Subsidiary Body for Implementation. GEF seeks to reduce GHG emissions by investing in new, low-GHG emitting energy-generating technologies, thereby lowering their costs and increasing their market share. It provides developing countries with early experience in new, emerging, low-GHG emitting energy generating technologies, in niche applications, and thus contributes to the expansion of the demand for these technologies.

GEF has been instrumental in the past in funding the incremental cost of a few renewable energy projects in India, with a focus on wind, solar, biomass, and small hydro. However, there has been no project on clean coal technologies for power generation. In 1990, a World Bank/GEF project directly financed 41 MW of wind turbine installations in India. The project strengthened the capabilities of the Indian Renewable Energy Development Agency (IREDA) to promote and finance private-sector investments. The project also helped to raise awareness among investors and banking institutions of the viability of wind power technology. As a result of the project and the generally favorable market conditions, many financial institutions decided to offer financing for wind farms, which was a key project goal. Such efforts in the coal-based power sector will be needed by GEF but on much larger scales.

In addition, GEF has also been instrumental in channeling private investments. GEF has recently created a Public-Private-Partnership Initiative (the Earth Fund) to more effectively engage the private sector in programs providing global environmental benefits. GEF has already allocated $50 million to the Earth Fund and will create a new platform within the Earth Fund for technology transfer. This platform will seek to leverage venture capital funding for new clean technologies through both the private sector and multilateral financing sources using a variety of tools. Future GEF work will make greater use of this innovative window and will report publicly on its deployment. This platform could be used for leveraging private investments and for promoting technology transfer for clean coal projects.

The estimated incremental cost requirements (table 5.1.2) are in the range of U.S.$29–31 billion in the last Plan period (2027–2032). However, these figures are substantially higher than the funds that GEF can provide. The fourth replenishment of GEF consists of $3.13 billion for funding operations between 2006 and 2010 for all developing countries together. Therefore, there is a need to design mechanisms that scale up financing for the incremental cost of new clean technologies.

Annex 2 shows a newly formulated Strategic Technology Programme by GEF. The program considers supercritical and IGCC technologies under fossil fuel generation to study the barriers and to better deploy and diffuse the technology.

Following the fourth replenishment, Annex I countries have also agreed on an ambitious set of reforms to improve the efficiency and effectiveness of the institution.

- Develop a programmatic approach
- Simplify the approach to applying incremental cost

These two reforms are needed in the coal-based power sector. Not only will they reduce the operating cost but they will also facilitate faster access to funds and avoid the long project approval cycle that most of the GEF-funded projects have to face.

GEF can prove to be a useful mechanism to fund the incremental cost of these new technologies. However, the total replenishment of the fund is a small percentage of the incremental cost required for power projects. Therefore the success of the mechanism in covering the total incremental cost is limited. To meet these huge costs, there is a need either to increase the funds in GEF or to explore ways to channel finance from developed countries to developing countries through the UNFCCC.

5.4.3 Private sector finance

UNFCCC documents state that private finance is one of the most important sources for financing clean technologies. It is estimated that the average annual investment in clean technologies made by private sources is approximately U.S.$148 billion (UNFCCC 2008). Therefore, this constitutes the single largest source of clean technology finance in the world.

Private sector finance is mainly under two broad categories, namely private finance for clean energy and FDI. The estimates provided by officials report the contribution of sources of private finance as follows:

Table 5.4.3.1. Global new investment in clean energy in 2004–07 (US$ billion)

Year	Venture Capital/Private Equity	Public markets	Government/corporate R&D and demonstration	Asset finance	Small-scale projects
2004	1.7	0.7	10.3	12.4	8.2
2005	3.0	4.1	12.3	27.5	11.6
2006	7.3	10.5	14.3	48.0	12.5
2007	9.8	23.4	16.9	79.2	19.0

Source: UNFCCC 2008

The numbers indicate that asset financing accounts for most of the investment in clean energy. The term *asset finance* includes debt raised from sources such as banks, capital markets, international financial institutions, ECAs, and so on. Investment raised through public markets has also become a large

component of technology financing. Another important source from the current perspective includes venture capital and private equity investments that support clean technologies.

The second form of private finance is constituted by FDI. The FDI relevant to clean technologies is typically in the form of greenfield investments, that is, where transnational corporations establish new facilities abroad.

Despite the large potential promised by this sector, it should be noted that the funding secured from private sources would entail interest costs. Therefore, raising debt from external sources would increase the cost of the project and electricity generation, and the projects in the developing countries will have to foot this increased bill. This is in direct violation of the Bali Action Plan and articles 4.3, 4.4, 4.5, and 4.7 of the UNFCCC, all of which lay down legally binding commitments on the part of the developed countries to provide financing to the developing countries to implement the UNFCCC. Accordingly, commercial funding from private sources would need to be augmented by fiscal sources from developed countries to meet the incremental investment and economic costs in the form of nonrepayable government support under the Convention.

Therefore, the aim should be not only to fund these incremental costs by such mechanisms but also to provide for instruments that allow transfer of funds from developed to developing countries to support these technologies.

5.4.4 Multilateral/Bilateral Finance

The Bali Action Plan notes the importance of multilateral bodies such as the multilateral development banks (MDBs) in supporting both mitigation of climate change and adaptation to the impacts of climate change "in a coherent and integrated manner." Over the past few years, MDBs have made many new initiatives to support climate change mitigation efforts. Most of the Bank's activities in this field are cofinanced by the GEF or by purchasing project-based GHG emission reductions through its various carbon funds. Some of the important ones are mentioned in table 5.4.4.1.

Table 5.4.4.1. New bilateral and multilateral climate-related initiatives

		Estimate level of funding (millions)	U.S.$ million equivalent	Purpose	Type	Period	Nominal annual level of funding (U.S.$ million)
Bilateral initiatives							
Cool Earth Partnership (Japan)	USD	10,000	10,000	A, M	G, L	2008–12	2,000
ETF-IW (United Kingdom)	GBP	800	1,182	A, M	G, L	2008–10	394
Climate and Forest Initiative (Norway)				M	G, L		<600

UNDP-Spain MDG Achievement Fund	EUR	90	114	A, M	G	2007–10	28.5
GCCA (European Commission)	EUR	60	76	A, M	G	2008–10	25.3
International Climate Initiative (Germany)	EUR	600	764	A, M	G	2008–12	153
IFCI (Australia)	AUD	200	132	M	G	2007–11	26.4
Multilateral Initiatives							
UN-REDD	USD	35	35	M	G	Not available	Not available
Forest Carbon Partnership Facility (World Bank)	USD	300	300	M	G, L	2008–20	23
Climate Investment Funds (World Bank), includes	USD	6341	6,341			2009–12	1,558
Clean Technology Fund	USD	4,334	4,334	M	G, L		
Strategic Climate Fund, includes	USD	2,006	2,006		G, L		
Forest Investment Program	USD	58	58	M	G, L		
Scaling-up Renewable Energy	USD	70	70	M	G, L		
Pilot Program for Climate Resilience	USD	240	240	A	G, L		

Source: UNFCCC 2008

Notes: A= adaptation, G = grants, L = loans, M = mitigation, AUD = Australian dollars, EUR = euros, GBP = British pounds, USD = U.S. dollars.

Among the above sources, the Cool Earth Partnership and the Climate Investment Funds are most significant. However, funds allocated by both these sources would be in the form of concessional loans. This marks a clear departure from the earlier paradigm of growth-oriented grants that the World Bank has followed.

In "Illustrative Investment Programs for the Clean Technology Fund," the Climate Investment Fund (CIF) discusses potential for including IGCC with CCS under its technologies supported. It provides a possible breakdown of project funding by different funding agencies. It has been outlined that the CIF grant element in total financing would be approximately only 11–15%. First, the U.S.$1 billion allocated for clean coal technologies would not be enough to satisfy even the needs of the coal-based power generation sector alone in India (see table 5.1.3). Second, because the rest of the amount (almost 90%) will be loan based, this will increase the incremental cost by adding the interest component.

This fact has also drawn flak from developing countries because such a structure violates the principle of common but differentiated responsibility. Because the problem of climate change has been caused primarily by activities of the developed countries, it is not correct to ask developing countries to foot the bill for their mitigation efforts entirely. A recent report by Sustainable Energy and Economy Network, Institute for Policy Studies, criticizes the CIF and argues that it is inadequately governed and usurps the role that many nations want the United Nations to play. By providing loans, it would indirectly force developing countries to pay for the industrialized world's pollution, thus increasing the already high level of indebtedness of developing countries and economic dependence on international donors.

The control over such funds should be established under the UNFCCC "in order to ensure they are used equitably and effectively, in accordance with the principle of common but differentiated responsibility, and that nations receiving financing are thoroughly involved in funds' design and implementation."(see discussion in UNFCCC website www.unfccc.int). Existing proposals to upscale international financing mechanism have been looked into in the course of the project (details given in Annex 1).

5.5 Proposals under discussion to scale up international finance

As noted in the earlier sections, the magnitude of public funds currently available is insufficient to satisfy developing countries' climate mitigation efforts. In this regard, different countries have submitted proposals to the AWG-LCA (Ad-hoc Working Group for Long term Cooperative Action) for scaling up resources to address climate change. Some of the important ones are mentioned in table 5.5.1.

Table 5.5.1. Particulars of proposals submitted to the AWG-LCA by different countries

Proposal	**Nature of public finance**	**Potential resource generation (US$ billion)**
G-77 and China proposal	Defined budgetary support	201–402
World Climate Change Fund (Mexico)	Dedicated budgetary contribution and additional revenue from auctioning	10
AAU Auctioning (Norway)	Auctioning of small portion of assigned amount units	15–25
Uniform global carbon tax (Switzerland)	International taxes	48.5 (total) 18.4 (for international fun

Source: UNFCCC 2008

In the Group of 77 (G77) plus China proposal, defined contributions from the Annex I parties as a source of finance have been proposed. This is an innovative suggestion as this is in sharp contrast to the voluntary or market-based contribution currently given. It has been suggested that these countries should contribute 0.5–1% of GDP for this purpose. These funds could be raised from environmental and energy taxes in these countries, revenues from permit auctions, public budgets, and so on. Furthermore, these funds would be "new and additional" in the sense that the funds generated would be over and above the Official Development Assistance, and in fact not in the name of "aid."

In addition to the financial mechanism, the proposal also suggests a technology mechanism. The funds collected would form a Multilateral Climate Technology Fund to support R&D, capacity building, and deployment and transfer of new technologies.

Mexico has proposed the establishment of a World Climate Change Fund (Green Fund) that would be financed through defined contributions from all countries based on their GHG emission levels, population, and GDP. It is proposed that this fund would support mitigation and adaptation efforts as well as promote transfer and diffusion of clean technologies. It should be noted that the design of this mechanism is such that countries would contribute in accordance with the principle of common but differentiated responsibilities and respective capabilities. In addition, it has been proposed that developing countries that choose not to join the fund would be excluded from its benefits but would not face penalties. It should be noted that the opt-out option may lead to some controversy, as some of the developed countries also would like to not participate in the process. In addition, the formula for defining contribution from countries is not completely watertight.

Norway has proposed the auctioning of a share of assigned amount units by all parties. These could be auctioned directly or through a tax on issuance of the allowances. However, this system presupposes the existence of a cap-and-trade system within all parties. Moreover, the proposal is silent on the question of the number of allowances to be auctioned and the purpose for which the resources would be used. It is also expected that funds generated through such a mechanism would not be sufficient to satisfy the needs of the developing countries for financing their mitigation and adaptation efforts.

The proposal submitted by Switzerland explores the possibility of a global carbon tax of U.S.$2 per tonne CO_2 emission. Keeping in mind the principle of common but differentiated responsibilities and the polluter-pays principle, it is also said that countries with emission levels below 1.5 tonne CO_2 equivalent per inhabitant would be exempted from the tax. Because countries with higher emission levels also have higher per capita incomes, this levy would lead to significant contributions from the developing countries. The funds collected would be divided into two parts: the Multilateral Adaptation Fund and the National Climate Change Fund. As the names suggest, the former would finance adaptation policies, while the latter would concentrate on adaptation, technology transfer, and/or mitigation policies.

5.6 Proposed funding mechanism for the Indian coal-based power generation sector

In light of all the mechanisms discussed above and linking them to the international negotiations on climate change, it can be observed that at present both the mechanisms under the Convention, that is, CDM and GEF, are not sufficient to meet the incremental cost of the magnitude required for the Indian power sector. However, CDM is an important mechanism in revenue stream, as the levelized cost of production of power from supercritical is more than that from subcritical.

The above section also discusses private investments and debt options. The private sector will have a large role to play in clean energy investments and therefore it is envisaged that private sector investments will be key for this sector. However, mechanisms that result in additional interest burden, such as the multilateral/bilateral loans and private funds, are not aimed for the initial stages of technology development until the technology reaches commercial viability and should be supported by public finance.

From the study, it can be seen that funds to the extent of U.S.$33 billion are required in the sector to move to clean coal technologies, which at present is not addressed by the existing mechanisms under the Convention and other multilateral fund. The G77 proposal proposes a quantum of funds that is commensurate with the demands from the sector. It may be concluded that the present G77 plus China proposal addresses the majority of these issues. The G77 and China proposal submitted to the AWG-LCA seeks to potentially raise substantial funds to the tune of U.S.$200–400 billion. If accepted, this can fund the incremental costs required for clean coal technology projects in developing countries including India. Therefore we recommend the use of an international mechanism on these lines to augment the incremental cost required for Indian coal-based power sector.

A dedicated fund for the sector is an interesting idea to explore within an umbrella of a fund dedicated to important sectors resulting in large emission reduction. However, nothing concrete at present is being discussed and therefore aiming to operationalize the G77 proposal will be crucial.

It would be important that any international financing mechanism be based on the following parameters:

- Flow of funds should be from Annex 1 to Non-Annex 1 Parties.
- It should follow the principle of common but differentiated responsibility.
- Funds should be sufficient, predictable, credible, and measurable.

Such a financial mechanism can support implementation of national policies with mitigation benefits in developing countries. It can be used to fund mitigation opportunities whose cost is substantially higher than the market price of emission reduction credits.

Annex 1

Necessity for CDM Revenue Support for Supercritical Thermal Power Projects

Establishment costs of a supercritical thermal power plant are higher than those of a subcritical thermal power plant. For a 2,000 MW plant, the establishment cost with supercritical parameters is about Rs. 8,000 crores, while with subcritical parameters it is around Rs. 6,500 crores. [7]

A study by Shrivastava (2007) shows that the actual cost-effectiveness of the technology comes as a reduction in the operational or variable costs of the plant, primarily due to reduction in the input cost (i.e., coal). Table A1 below shows the difference of cost between two technologies for a 2,000 MW project. Suresh et al. (2006) assumes coal savings with a 3% efficiency gain while Jayadevan's calculations are based on 1% gain.

The average life of a supercritical thermal power plant ranges from 30 to 40 years.[8] Thus, it would take almost its full life for a supercritical plant to recover its additional establishment costs through savings in its operational costs. Therefore, even in the long run, a supercritical plant does not reduce the total expenditure below the subcritical plant expenditure. It is in this context that the institutional factors play a major role in making a supercritical plant cost-effective as compared to a subcritical plant. The cost-effectiveness of a supercritical plant is primarily due to various norms and regulations. Various institutional arrangements allow a supercritical plant an advantageous position, compared to subcritical plants. While technological factors affect the expenditure side of a supercritical plant, institutional factors affect the revenue side. The most important institutional mechanism that adds to the revenues of a supercritical plant is the provision of carbon credits trade through CDMs. These revenue-side advantages are not available for subcritical plants.

Table A1. Savings in coal consumptions and expenditure on coal due to supercritical technology

Base Study	Coal savings in tonnes/year	Expenditure savings (in crores)	Time required to cover the cost difference from subcritical plant	
			Rs. 1,700 crores	Rs. 2,000 crores
Suresh et al. (2006)	6.1 lakh	59	28 years	33 years
Jayadevan (n.d.)	6.6 lakh	62	27 years	32 years

Sources: Calculated from Suresh et al. (2006) and Jayadevan (n.d.).

[7] See answer to the Parliamentary Question No. 4346 on 19-06-2006.

[8] For example, the Big Stone-II supercritical plant with 630 MW unit size has an expected plant life of 40 years. (See http://www.bigstoneii.com/PlantProject/PlantQandA.asp#p1 accessed on July 10, 2007, at 5:00 pm.)

Table A2. Cost and revenue benefits of supercritical technology

Base Study	Coal savings in tonnes/year	Additional earnings from emissions trade (in crores)	Expenditure savings due to reduced coal consumption (in crores)	Time required to cover the cost difference from subcritical plant (2,000 MW)	
				Rs. 1,700 crores	Rs. 2,000 crores
Suresh et al. (2006)	6.1 lakh	60	59	15 years	17 years
Jayadevan (n.d.)	6.6 lakh	65	62	14 years	16 years

Source: Calculated from Suresh et al. (2006) and Jayadevan (n.d.).

As technological savings would take almost the whole life of a plant to level the establishment costs difference from a subcritical plant, it can be argued that in the absence of a carbon credits provision, a supercritical plant might be a loss-making investment as compared to a subcritical plant. At best, it could be equivalent to a subcritical plant in terms of profit making. It can be seen from the table that the incremental cost of 1,700 crores can be covered with CDM benefits in 15 years as compared to 28 years and 17 as compared to 33 for 2,000 crores.

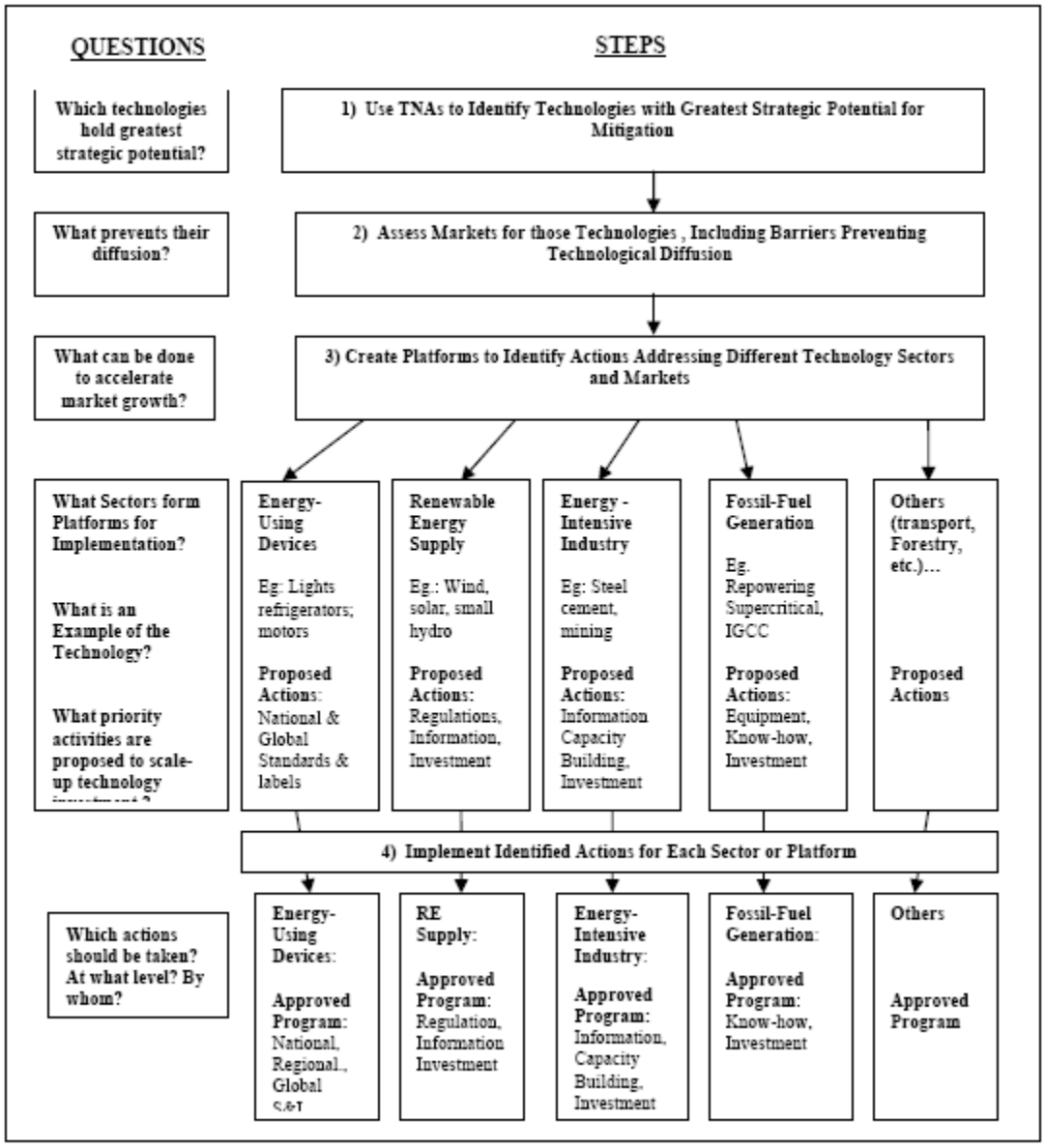
Also it has been seen from PDDs (Sasan) of proposed projects that the levelized cost of generation (INR/kWh) from a supercritical-technology-based power plant (based on imported coal) is much higher with regard to the levelized cost of generation from a subcritical power plant (based on Indian coal), which the project proponent would have gone for in the absence of the proposed project activity. This demonstrates the relative unattractiveness of power generation through supercritical technology.

Coal-fired supercritical-technology-based UMPP at Mundra during the conceptualization of the proposed CDM project activity considered the potential CDM revenue that would flow to the proposed project activity. The following impacts of the CDM fund are identified from the point of view of mitigation of risks and barriers discussed above.

- The CDM fund will provide additional coverage to the risks associated with the proposed project activity and help in mitigating the other technical risk factors as mentioned above.
- The fund will stimulate R&D efforts in Combustion, Gasification and Propulsion Laboratory to find methods of mitigating risks and enhance replication of such advanced power generation technologies to achieve GHG abatement.

Annex 2

Formulation of a Strategic Technology Program on Mitigation by GEF



Source: GEF 2008b

References

Abbi, Y. P. 2003. Technologies and policies to mitigate atmospheric pollution from thermal power plants. *Proceedings of the International Conference on Thermal Power Generation* (*Best Practices and Future Technologies*), 13–15 October, 2003, New Delhi.

Bakshi, A. S., and Amarjeet Singh. 2008. "Increased Efficiency in Power Generation." Paper presented at Indo-EU Workshop on Clean Coal Technology, New Delhi, November 27, 2008.

Beijing High Level Conference. 2008. "Climate Change: Technology Development and Technology Transfer Background." Paper prepared for the Beijing High-level Conference on Climate Change: Technology Development and Technology Transfer, Beijing, China, 7–8 November 2008.

Capacity Development for the CDM. 2009. http://www.Cd4cdm.org (accessed January 9, 2009)

CEA. 2007a. 17th Electric Power Survey of India Report, Central Electricity Authority, Ministry of Power, Government of India.CEA. 2007b. National Electricity Plan, Vol I. Central Electricity Authority, Ministry of Power, Government of India.

CEA. 2008a. Shelf of projects for likely benefits during XIIth plan. Central Electricity Authority, Ministry of Power, Government of India.

CEA. 2008b. Baseline Carbon Dioxide Emission Database Version 4.0. http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm (accessed January 1, 2009)

CEA. 2008c. Performance Review of Thermal Power Stations for 2006–07, Central Electricity Authority, Ministry of Power, Government of India.

CEA. 2008d. All India Electricity Statistics (General Review). Ministry of Power, GOI.

CEA. 2008e. Paper presented by CEA at Indo-EU Workshop on Clean Coal Technology. New Delhi, November 27.

CEA. 2009. http://www.cea.nic.in/power_sec_reports/executive_summary/2008_03/9-10.pdf (accessed February 25, 2009)

CIF. 2008. Illustrative investment programs for the Clean Technology Fund. Report No. CIF/DM.2/Inf.2/Rev.1, Design meeting on Climate Investment Funds, Potsdam, Germany, May 21–22, 2008

GEF. 2008a. *Investing in Our Planet: GEF Annual Report 2006–07*. Washington, D.C.: Global Environment Facility

GEF. 2008b. Elaborating a Strategic Program to Scale-Up the Level of Investment in the Transfer of Environmentally-Sound Technologies. Report no. GEF/LDCF.SCCF.4/5, LDCF/SCCF Council Meeting, April 25, 2008.

GOI. 2006. Country presentation by India at COP 12- Nairobi, November 2006, and Vienna Climate Change Dialogue, August 2007. Presented by The Energy and Resources Institute, New Delhi on behalf of the Government of India.

GOI. 2008. Statement to UN General Assembly by Ministry of Power, Government of India. http://www.un.int/india/2008/ind1457.pdf

IEA. 2008a. GHGT 9 Conference Summary. Proceedings of the 9th International Conference on Greenhouse Gas Control Technologies, November 16–20, 2008, Washington, D.C.

IEA. 2008b. *World Energy Outlook 2008*. Paris: International Energy Agency

Jayadevan, C. (n.d.). Supercritical Boilers, Power Point Presentation, BHEL-Tiruchirappalli. http://www.greenbusinesscentre.com/documents/Supercritical%20Boilers.pdf (accessed September 10, 2006).

Perspectives. 2008. Supercritical coal power plant methodology approved by CDM EB. http://www.perspectives.cc/News.56.0.html (accessed January 9, 2008)

Planning Commission. 2006. *Integrated Energy Policy.* Planning Commission, GOI.

Planning Commission. 2007. Working Group on Power for the 11th Five Year Plan. Ministry of Power, GOI.

PMCCC. 2008. National Action Plan on Climate Change. Prime Minister's Council on Climate Change, GOI.

Redman, J. 2008. *DIRTY IS THE NEW CLEAN: A Critique of the World Bank's Strategic Framework for Development and Climate Change*. Sustainable Energy and Economy Network, Institute for Policy Studies.

Shrivastava, M. K. 2007. *Convergence in Climate Change Institutions and Consequences for Developing Countries: A Case Study of Supercritical Technology Adoption by NTPC.* M.Phil. Dissertation. New Delhi: Jawaharlal Nehru University.

Suresh, M. V. J. J.*, Reddy, K. S., and Kolar, Ajit Kumar. (2006). "Energy and Exergy Analysis of Thermal Power Plants Based on Advanced Steam Parameters." *Advances In Energy Research*, pp. 15–21.

TERI. 2006. National Energy Map for India – Technology Vision 2030. Prepared for the Office of the Principal Scientific Advisor to the Government of India, GOI.

UNDP. 2005. *Human Development Report.* United Nations Development Program.

UNDP. 2007/2008. *Human Development Report 2007/2008*. Watson, J., MacKerron, G., Ockwell, D., and Tao Wang, T. Human Development Report Office, Occasional Paper.

UNFCCC. 2007. Review of the experience of international funds, multilateral financial institutions and other sources of funding relevant to the current and future investment and financial needs of developing countries. Technical paper no. FCCC/TP/2007/4, United Nations Framework Convention on Climate Change, Bonn

UNFCCC. 2008. *Investment and Financial Flows to address Climate Change: An Update.* Technical report no. FCCC/TP/2008/7, United Nations Framework Convention on Climate Change, Bonn.

World Bank. 2005. *World Development Report.* Washington, D.C.: The International Bank for Reconstruction and Development, The World Bank.

Financial support provided by:

WWF

1250 24th Street NW
Washington, DC 20037
USA

Tel: +1.202.778.9752
Fax: +1.202.293.9211
Email: mpo@wwfus.org
Web: http://www.panda.org/mpo