The Suitability of Coal Gasification in India's Energy Sector

by

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Abstract

Integrated Gasification Combined Cycle (IGCC), an advanced coal-based power generation technology, may be an important technology to help India meet its future power needs. It has the potential to provide higher generating efficiency, can be adapted to efficiently burn India's high-ash coal, and has the potential to do so with greatly reduced emissions and offers the longer term potential to assist India to manage its CO2 emissions. Efficient gasification technology also offers India the potential to produce a variety of fuels, particularly transportation fuels, and chemicals. These potential benefits would be useful in a country that has coal shortages, runs inefficient power plants, and imports the majority of its transportation fuels.

Driven by these potential benefits the Central Government-owned power generating equipment manufacturing company (BHEL) is developing a fluid-bed gasifier designed for Indian coals, but has not yet demonstrated it at a size larger than 6 MW. Outside of BHEL, there are many factors holding this technology back. First, the technology is projected to be more expensive than pulverized coal (PC) power generation. In the Indian environment, the capital costs are estimated to be 1.5 times higher, and the levelized cost of electricity is estimated to be 33 % higher than for PC power generation. Further, there are other technology options, such as super-critical pulverized coal technology, which are cheaper, more proven, and can provide immediate higher generating efficiency. The first supercritical PC plant is currently being built in India.

To overcome these barriers will take further research and development, as well as demonstration at a commercial scale. This all needs to occur at a greater speed and with a greater urgency than is now apparent. The demonstration and commercialization will require significant subsidies, which may come in different forms. The Central Government may wish to subsidize the technology development for the pollution control benefits that it offers and do so via its linkages to BHEL. Foreign governments and institutions may choose to subsidize the costs for the carbon dioxide reduction credits that it can produce.

In the end, the challenges facing IGCC in India are great. The cost and generating efficiency will have to at least rival those for other advanced coal technologies, and coal production and mining policies will have to be effectively enacted to increase the supply of coal available for new coal plants.

Thesis Supervisor:
Dr. James Katzer
Prof. Richard Lester

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Para los que promueven la paz en el mundo.

For my mother who has given me so much while putting up with so much. She has continued to be a strong person and has shown me a great example in the importance of striving to be the best person possible.

For Poppee, who has encouraged me more than anyone and to whom I could always look for good advice. He has been a great inspiration for me in many ways.

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I would like to thank my advisor, Dr. Katzer: the person who retired so that he could have multiple jobs instead of just one. For the time he dedicated working with me on my thesis and giving me guidance. I appreciate the time he spent to teach me. And for Professor Lester who sparked my initial interest in energy and has helped me throughout the process of writing the thesis.

For my sisters, who have taught me many things. For Jennifer who has taught me to be happy and enjoy. For Kristen who has taught me to enjoy every minute while releasing the burdens that are put upon us.

Finally for all the people that met with me and aided me in my travels and tour in India. Especially SK Chand at TERI who guided me in my maneuvering through such a tireless and tiring country. For RS Rangan at BHEL who taught me about gasification and facilitated this learning through site visits.

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ACRONYMS

BHEL	Bharat Heavy Electricals Ltd.
CEA	Central Electricity Authority
CenPEEP	Center for Power Efficiency and Environmental Protection
CERC	Central Electricity Regulatory Commission
CIL	Coal India Ltd
CRW	Combustibles, renewables, and waste
DisCos	State distribution companies
EPPA	Emissions Prediction and Policy Analysis
FBG	Fluidized bed gasification
F-T	Fischer-Tropsch
GenCos	State generation companies
GoI	Government of India
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IICT	Indian Institute of Chemical Technology
MIT	Massachusetts Institute of Technology
MoC	Ministry of Coal
MoD	Ministry of Disinvestment
MoP	Ministry of Power
MoR	Ministry of Railways
MW	Always refers to MW electric and not thermal
NGRI	National Geophysical Research Institite
NLC	Neyvelli Lignite Corporation
NTPC	National Thermal Power Corporation
PC	Pulverized coal
PCB	Pollution control board
PPA	Power purchase agreement
PSU	Public sector undertaking
SEB	State Electricity Board
SERC	State Electricity Regulatory Commission
T&D	Transmission and distribution
TERI	The Energy and Resources Institute
TPES	Total primary energy supply
TransCos	State transmission companies
Unit	Refers to 1 kWh

INTRODUCTION: COAL USE IN INDIA

The average Indian consumes 1/16th as much primary energy as a person living in the United States.[1] Less total energy is consumed in India, which has between 3.5 times the population of the United States. Yet this is changing as India grows and begins to consume a lot more energy, leading to more CO_2 emissions.

India has a high GDP growth rate (7.8% in 2005) and a high energy growth rate. Reforms have been initiated in the power sector to lead to better quality service, and the government has plans to quickly electrify rural areas and thus exchange biomass use for commercial electricity. The most likely source to fuel this growth in electricity is coal. Coal is the largest fuel resource in India (in terms of reserves to production). There is already a large established infrastructure for coal, although there are significant bottlenecks in the supply chain. The drawback to coal is that it emits the largest amount of CO_2 per kilowatt-hour of electricity generated for all energy sources. This means that India's CO_2 emissions will increase over the coming years.

One method to mitigate these emissions while potentially achieving higher efficiency in the coal sector is by building new coal plants with advanced technology. One such technology the integrated gasification combined cycle (IGCC) power plant. Along with its benefits, IGCC has many potential drawbacks. The benefits and drawbacks to IGCC are specific to the energy context in India as well as government policies.

This thesis will explore the suitability of IGCC in India considering the unique characteristics and constraints of the Indian power sector.

A background of energy use in India will be given. Government policies relating to electricity generation and coal production will be looked at to understand how the policies currently support or could support IGCC in the future. The current methods for using coal in electricity production will be discussed along with the current production technologies. Existing technology and its adaptation to Indian conditions and coal quality are important to consider in understanding whether advanced technology could fulfill the same needs and requirements. Finally, the benefits provided by the technology will be discussed to show whether this technology would be beneficial to India.

[1] Based on total primary energy supply per capita.

1. PRIMARY ENERGY

Energy is important for economic development and growth in India, especially considering the fast pace of economic growth. This chapter will give a broad background on India's production and consumption of various fuels. Historically biomass has been India's largest source of energy and has been consumed residentially. However, with increasing electrification of villages, electricity generated using commercial fuels is displacing the biomass. The increasing levels of electrification as well as economic growth are driving increased consumption of commercial fuels. Consumption of most fuels is rising faster than domestic production of the fuels, leading to greater dependence on imports.

India is the world's second most populous country, with a population of 1.10 billion people. The population is projected to grow to 1.45 billion in 2030 (equal to population forecasts for China).[2] The Indian GDP has grown at an average real growth rate of 6.6%/year over the last five years. The real GDP growth rate was 7.8% in 2005 and is predicted to be 8.1% in 2006.[3] Table 1 shows IEA estimates that India's share of global gross product (national GDP is on a purchasing power parity basis) will increase from 3.1% to 5.9% while its share of global population will stay constant at 17% between 2005 to 2020.

Table 1: GDP and Population Growth[4]

	2005 Share / Rank		**2020 Share**	**1997-2020 Projected Real Annual Growth Rate**
GDP (US$ in PPP)	3.1 %	4th	5.9 %	7.6 %
GDP (real US$)	1.8 %	12th		
Population	17 %	2nd	17 %	8.3 %

India is ranked 12th in terms of GDP (real US$), while the US is ranked first. India uses one fourth the primary energy as the United States, as shown below in table 2. Per capita consumption of (commercial fuel-based) energy in India is 1/16th that of the US. The energy intensity for India (1.02 tonnes of oil equivalent / thousand - 2000 US$ of GDP) is much higher than that for the US (0.22 tonnes of oil

[2] Population Division of the Department of Economic and Social Affairs of the United Nations Secretariat, "World Population Prospects: The 2004 Revision and World Urbanization Prospects: The 2003 Revision". 12 February 2006. Online: http://esa.un.org/unpp.

[3] Central Statistical Organisation, Ministry of Statistics and Programme Implementation, Government of India. 7 February 2006. Online: http://www.mospi.nic.in/nad_press_note_7feb06.htm.
Economist Intelligence Unit. "Country Report - Main report: December 13th 2005." Online: www.eiu.com.
According to the CIA World Factbook, India had a real GDP growth rate of 8.3% in 2003 and 7.1% in 2005, while that for China was 9.1% in 2003 and 9.2% in 2005. CIA. "The World Factbook." 09 February 2006. Online: www.cia.gov/. GDP per capita is $3400 in India and $6200 in China in 2005 at purchasing power parity (PPP).

[4] Projections from: Audinet, Pierre. "World Energy Outlook for India, 2000." Powerpoint presentation. IEA. 2000. Online: http://www.iea.org/textbase/papers/2000/indiaoutlook.pdf.
2005 data from: The World Bank. "Total GDP 2005." Online: http://siteresources.worldbank.org/DATASTATISTICS/Resources/GDP.pdf.

equivalent / thousand - 2000 US$).[5] India's high energy intensity could be due to low power generation and transmission efficiency, a larger base of energy-intensive industries, and/or inefficient equipment on the demand side.

Table 2: Comparison of energy statistics among India, the US, and China (2003)[6]

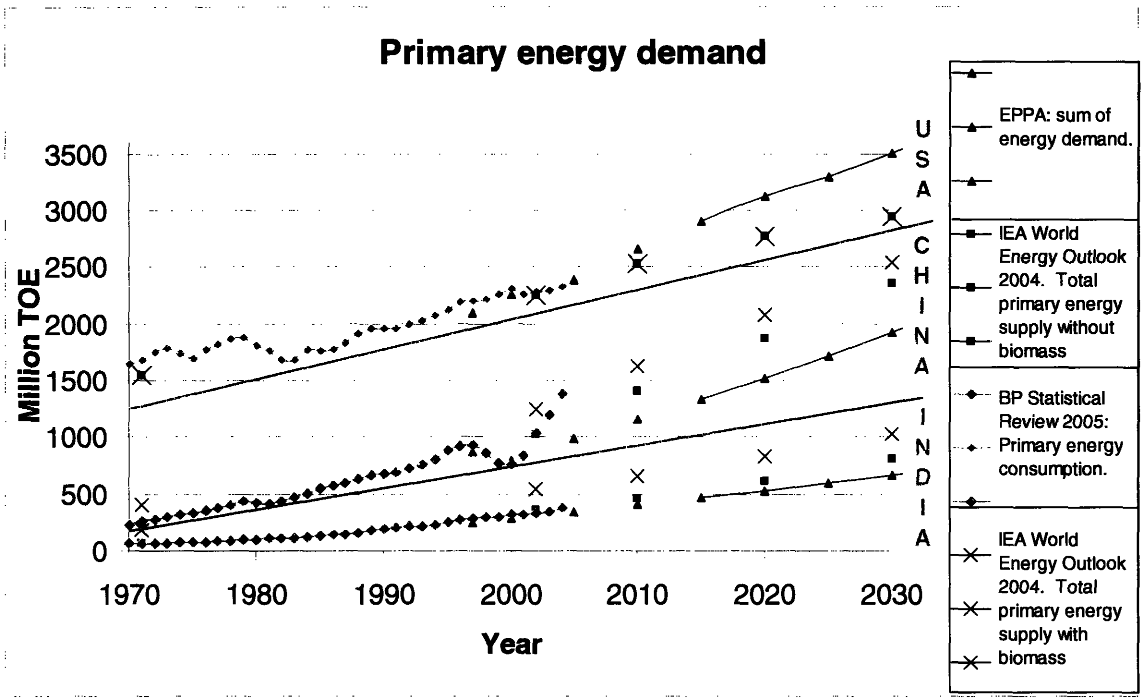
	India	US	China
Total primary energy supply million tonnes of oil equivalent (mtoe/yr) on a net calorific value basis	553	2281	1409
TPES/pop Tons of oil equivalent per capita	0.52	7.84	1.09
Energy Intensity TPES / GDP (toe/thousand - 2000 US$) / (toe/thousand - 2000 US$ PPP)	1.02 / 0.19	0.15 / 0.14	1.02 / 0.23
Total energy production (Mtoe)	455	1632	1381

The absolute energy use in the USA is higher than that for India and China, as shown in figure 1. China is expected to grow at a faster rate and narrow the gap. India's demand is shown to increase fairly linearly while that for China is expected to increase at a faster rate.

[5] Energy intensity is the total primary energy supply (TPES) per GDP in thousand US dollars, currency in 2000 US$. IEA. Selected 2003 indicators for India.

[6] This only includes commercial fuels: non-commercial biomass is not included in these numbers.
IEA , OECD. Selected 2003 Indicators. Online: www.iea.org. Data from 2003.
US EIA data gives US primary energy production at 1,773 Mtoe and consumption at 2,530 for 2004. Original data for production is 99.31 quad BTU and consumption is 120.6 quad BTU, converted using 1 Btu = 2.52e-8 tonne of oil equivalent.
Energy Information Administration, US Government. "International Energy Annual 2004." May-July 2006. Online: www.iea.doe.gov.

Figure 1: Energy demand in the US, China, and India[7]



India was the 5th largest user of energy in the world in 2004, as shown in table 3. The IEA estimates that India consumed 18% of the world's combustibles, renewables, and waste (CRW) in 1997.

7 MIT Joint Program on the Science and Policy of Global Change. "The MIT Emissions Prediction and Policy Analysis (EPPA) model." MIT. Accessed March 2006. Based on 2000 IEA data. EPPA model results indicates how alternative CO_2 emission charges accomplish reductions through a combination of adjustments in the economy including fuel switching, lower energy demand, greater energy efficiency and a shift away from energy intensive industry, and, toward the end of the period, deployment of new technology.

Table 3: Indian fuel statistics[8]

	1997 World share / Rank	2004 World share / Rank	2020 World share
Energy consumption Excluding biomass	3.1 % / 7th	3.7 % / 5th	5.3 %
Coal consumption	6.8 % / 3rd	7.4 % / 3rd	10 %
Oil consumption	2.6 % / 11th	3.2 % / 6th	4.6 %
Gas consumption		1.2 % / 20th	
Nuclear consumption		0.6 % / 20th	
Combustibles, renewables, waste	18 % / 2nd		16.2 %
TPES (including CRW)	4.8 % / 5th	5.3 % / 4th*	6.3 %

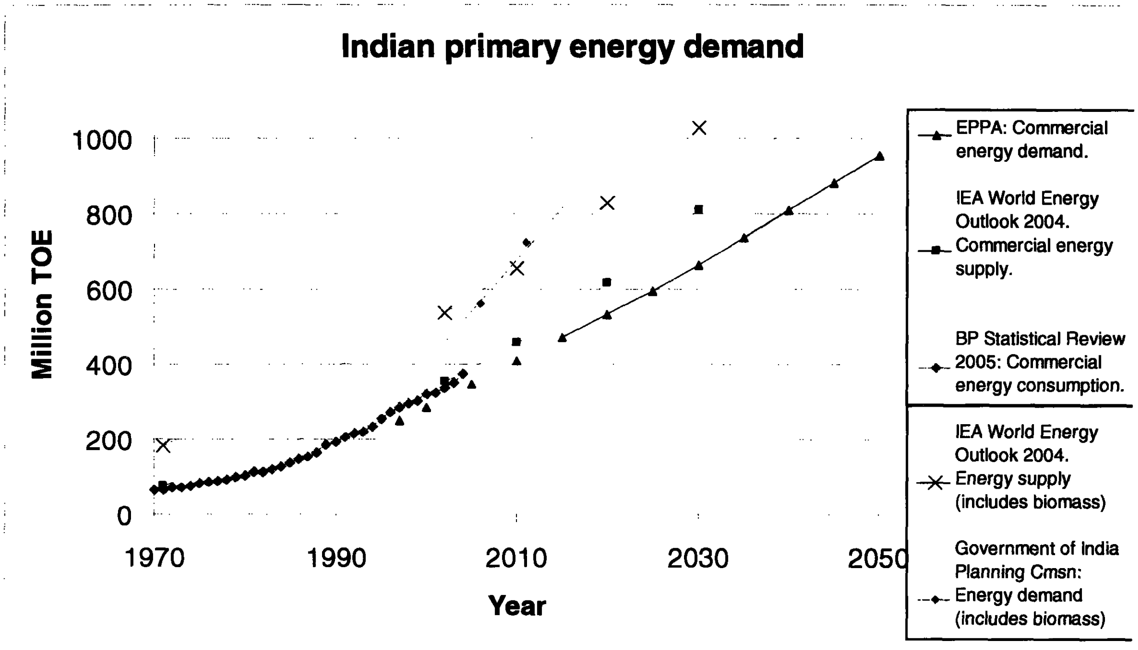
These statistics highlight the increased consumption of various fuels. Most notable is the increase in percent share of coal use. In 2020, India is forecasted to have 1/6 of the world's population and have 1/10 of the world's coal demand.[9] Similarly oil demand will increase. As India does not have large reserves of oil, this would result in increased imports. As an energy security concern, this could prompt the government to look into other ways to obtain liquid fuels such as solid to liquid technologies, converting coal to a liquid fuel. This would increase the demand for coal.

Energy consumption in India is forecasted to grow as shown in figure 2. Various international organizations have estimated the primary energy demand to grow at a fairly constant rate. The Government of India's Planning Commission has the highest growth figures.

[8] Data and forecasts from 1997 and 1997-2020 are supplied by: Audinet, Pierre. "World Energy Outlook for India, 2000." Powerpoint presentation. IEA. 2000. Online: http://www.iea.org/textbase/papers/2000/indiaoutlook.pdf.
Data for 2004 supplied by: BP. "BP Statistical Review of World Energy June 2005." Online: http://www.bp.com/statisticalreview.
Data for TPES (including CRW) for 2004 supplied by: IEA, OECD. 2005 Key World Energy Statistics. Online: www.iea.org. Data from 2003.

[9] See table 1 and table 3.

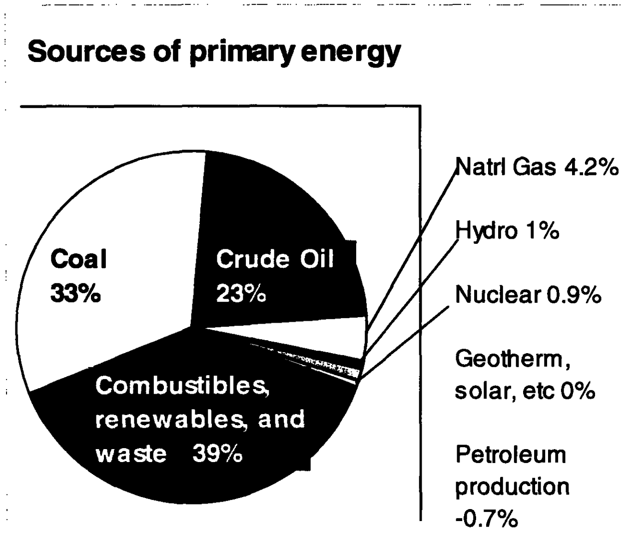
Figure 2: Primary energy demand (with and without biomass included) in India[10]
Data recorded from 1970 to 2004 with projections from 2004 to 2050.



The largest share of the primary energy in India is biomass as shown in figure 3. Biomass (combustibles, renewables, and waste or CRW) accounts for 39% of primary energy consumption and is used mostly by the rural population that does not have access to electricity. Coal is the second largest source of primary energy at 33%, followed by crude oil at 23%.

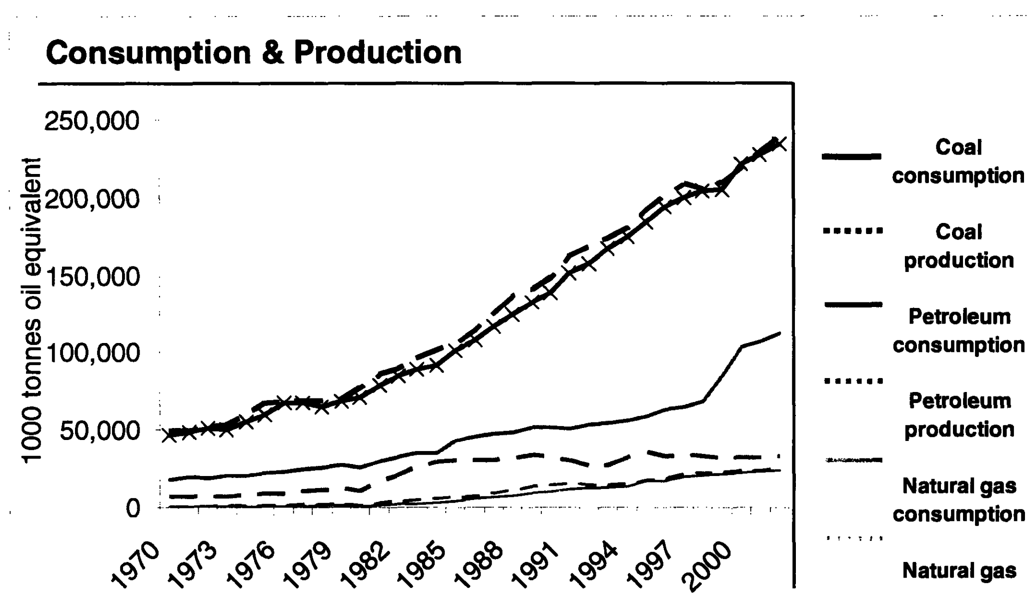
[10] **EPPA**: Energy demand without biomass. Based on 2000 IEA data received in units of EJ. Data exported from EPPA in EJ. BAU carbon policy, ref gas price, limited nuclear expansion.
IEA: TPES w/ biomass. TPES w/o biomass. Consumption w/ biomass. Consumption w/o biomass. Total primary energy supply is equivalent to primary energy demand. Total final consumption is the sum of consumption by the different end-use sectors. Data given in toe. I converted with IEA convention of 0.041876 EJ / mm toe. (EPPA uses 0.042). Data from: OECD, IEA. "World Energy Outlook 2004." Online: www.iea.org.
EIA: TPE Consumption w/o biomass. I converted from BTU using EIA's suggested: 1 Btu = 1.055 kJ. Data includes only "marketed (i.e., commercially traded) sources of energy. Data from: Energy Information Administration (EIA), Department of Energy (DOE), Government of USA. Energy Data. Accessed: February 2006. Online: http://www.eia.doe.gov/.

Figure 3: Sources of primary energy supplying India's total energy demand[11]



Historically, the consumption of commercial fuels has been dominated by coal as shown in figure 4. While coal has increased significantly, so has petroleum. The difference between the petroleum consumption and production further illustrates the lack of national oil resources.[12] The use of natural gas remains small in comparison. It has grown from a base of almost zero in 1970. Most natural gas comes from domestic production.

Figure 4: Consumption and production of commercial fuels in India



[13]

[11] IEA. "Selected 2002 indicators for India."

[12] The increasing oil imports may drive consumption of synthetic transportation fuels.

[13] Ministry of Statistics and Programme Implementation. Energy data.

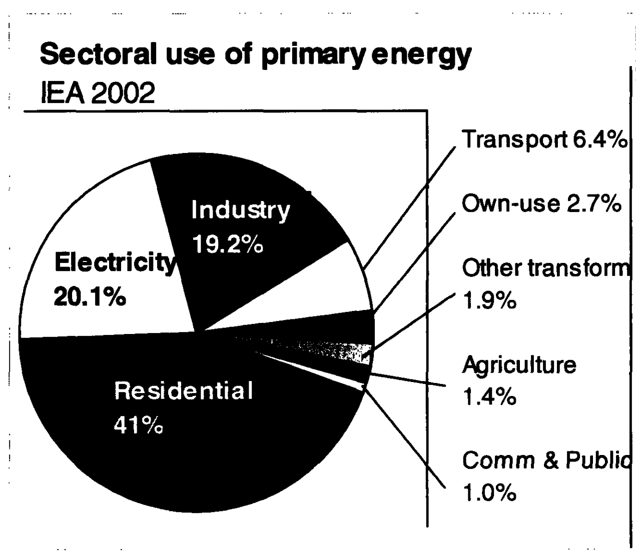
The current coal reserves to production ratio (table 4) shows that India could continue current production of coal for about 230 years, but has proved gas reserves for only 31 years for gas at current production and proved oil reserves for only 19 years for oil. Proved gas and oil reserves can be expected to be increased with further exploration.

Table 4: India's proved reserves at end 2004[14]

	Proved reserves at end 2004	Share of world total reserves	Reserves to production ratio[15]
Coal (mm tonnes)	92,445	10.2%	229 yrs
Oil (billion barrels)	5.6	0.5%	18.6 yrs
Gas (trillion cubic ft)	0.92	0.5%	31.3 yrs

The majority of primary energy (and CRW) is used in the residential sector.[16] The second largest use is in the electricity sector, followed closely by industry. Transport accounts for only 6% of primary energy.

Figure 5: India's sectoral use of primary energy



Along with this consumption comes the release of greenhouse gases such as CO_2. With 1016 million metric tons of carbon dioxide released from the consumption and flaring of fossil fuels in 1999, India ranked fifth in CO_2 emissions in the world behind the United States, China, Russia and Japan (US Energy Information Administration, 1999). India emits about 1/5 as much CO_2 as the US and 1/3 that of China.

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[14] BP. "BP Statistical Review of World Energy."
"Proved reserves of coal - Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known deposits under existing economic and operating conditions. Reserves/Production (R/P) ratio - If the reserves remaining at the end of the year are divided by the production in that year, the result is the length of time that those remaining reserves would last if production were to continue at that level."
[15] The units are years of production available from reserves at 2004 production levels.
[16] IEA. "Selected 2002 indicators for India."

Table 5: CO_2 emissions in 2003[17]

	India	US	China
CO_2 Emissions Mega tons of CO_2	1050	5729	3719

This energy overview has shown that India's consumption of commercial fuels is rising faster than the production of fuels, leading to greater dependence on fuel imports. This could affect concern for national energy security in the Indian government and cause prices for electricity and other products, due to higher-priced imported fuels replacing domestic fuels. This is important to note in understanding what will be the priorities that the Indian government will address: fuel import independence, local pollution, or CO_2 emissions.

The following chapter will describe the policies related to power production. This will give insight into what the government is trying to promote in this sector.

[17] IEA. IEA 2005 Key World Energy Statistics. Emissions from commercial fuels only: CRW is not included.

2. ELECTRICITY

To achieve India's projected high annual GDP growth rate of 8%/year and to meet increasing power demand will require large investments in the power sector. Problems in the power sector have meant that new capacity build has not kept up with demand or central government plans. However, much of the increased supply has come through reform efforts that have improved the operating efficiency and plant load factor of existing power plants. These reforms also address problems such as power shortages, high technical losses in transmission and distribution, theft of power, power subsidies, and the financial state of the state utilities. Alleviating these problems should improve the disparity between electricity demand and supply.

These issues will be discussed in greater detail in this chapter. A background of the Indian power (electricity) sector will be given and government policies and reforms will be described.

Background

While India ranked fourth in terms of total primary energy consumption in the world (2003), it only ranked fifth (2004) in terms of electricity generation due to the use of biomass (shown in table 6).

Table 6: Indian electricity statistics[18]

	1997 World share / 1997 Rank	**2004 World share / Rank**	**2020 World share**	**1997-2020 Growth rate**
TPES (including CRW)	4.8 % / 5th	5.3 % / 4th	6.3 %	11.9 %
Final electricity demand	3 % / 8th	3.7 % / 5th	5.5 %	8.3 %

Total power production in India is less than a third that for China and less than 1/6th that for the US. The average American consumes 23 times as much electricity as the average Indian. India's Central Electricity Authority reports that 84% of villages had at least one electrical connection as of March 2004. The IEA estimates that 60% of households have access to electricity.[19] India's per capita electricity consumption, at 600 kWh / person, is quite low. Table 7 shows India's per capita electricity consumption is less than half of that for China and Brazil, but slightly more than Indonesia.

[18] Data and forecasts from 1997 and 2002 are supplied by: Audinet, Pierre. "World Energy Outlook, 2000."
Data for 2004 supplied by: BP. "BP Statistical Review of World Energy." Data for TPES (including CRW) for 2004 is 2003 data from: IEA. "2005 Key World Energy Statistics."

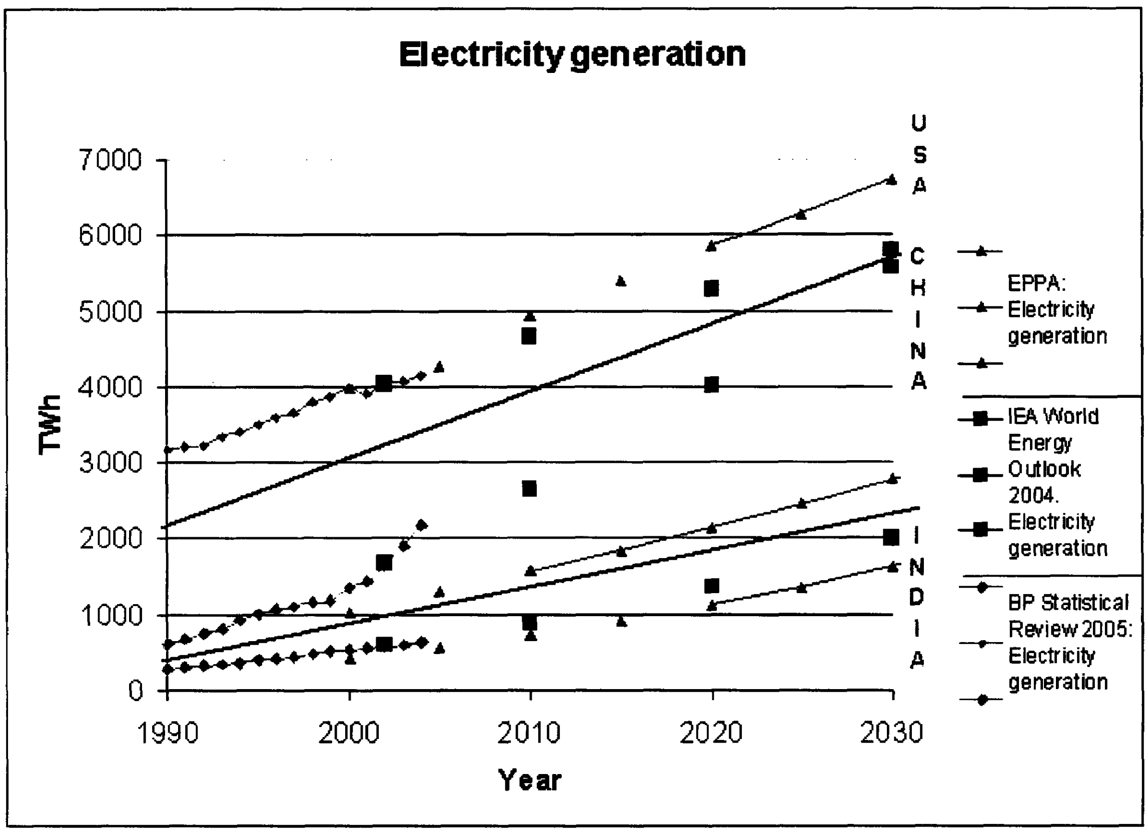
[19] Dickel, Ralf. Head, Energy Diversification Division, International Energy Agency. "Coal and Electricity Supply Industries in India: Key Issues". Conference on Coal and Electricity in India, New Delhi, India. 22 September 2003.

Table 7: Electricity generation comparison among India, the US, and other developing countries[20]

	India	US	China	Indonesia	Brazil
Electricity generation 2004 TWh	651	4,150	2,187	120	386
Per capita electricity generation kWh per capita	600	14,020	1,670	490	2,050

China's electricity generation is expected to increase rapidly, while India is expected to grow at a slower rate at shown in figure 6. Recent economic growth in China has occurred along with an upturn in electricity generation. India's electricity generation has not reflected the economic growth in the same manner. The EPPA projection is shown lower for China as it uses 2000 as its base and does not take into account the upsurge.

Figure 6: Electricity generation in the US, China, and India



India's recorded electricity generation is significantly higher than the recorded consumption due to losses in the transmission and distribution (T&D) system and the theft of electricity. 650 TWh of electricity was

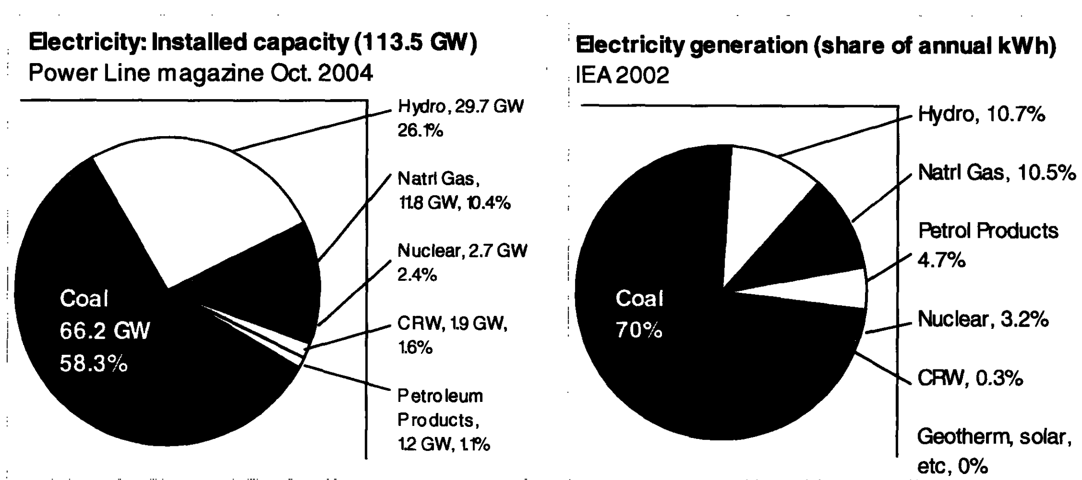
[20] BP. "BP Statistical Review of World Energy." Electricity generation based on gross output. Data from 2004.
Population based on July 2005 data from CIA. "The World Factbook."

generated in 2004 as shown in table 7. 7% of this generation was consumed in power plant auxiliaries. Of this amount, 361 TWh was sold to consumers as reported by India's Central Electricity Authority—representing about 2/3 of total power generation. These losses are highest in the northern region (37.5%), average in the eastern (33%) and western (33%) regions, and lowest in the southern regions (22%).[21]

India's installed capacity as of October 2005 was 124 GW.[22] 60% of this capacity is coal-based plants, followed by hydroelectric and natural gas plants. The share of major fuel sources is shown in figure 7 below. The breakdown of installed electrical capacity by fuel source differs from the breakdown of electricity generation by fuel source due to many factors. The load factor of the hydro plants is smaller in comparison to the load factors of other fuels due to seasonal water shortages. The share of electrical generation from petroleum is higher than the installed capacity of diesel generation sets (gen-sets). This is due to the unreliability of the power. During load shedding and power outages, diesel gen-sets are used for back-up power (as well as for captive power operations).

India also has about 4,000 MW of wind capacity and 613 MW of biomass-based power systems.[23] The central government wants to increase these numbers. As of December 2004, there were an additional 644 MW of biomass power proposed. The average size of biomass gasification systems is around 200 kW.[24]

Figure 7: Indian electrical installed generating capacity[25] and total power generation[26]

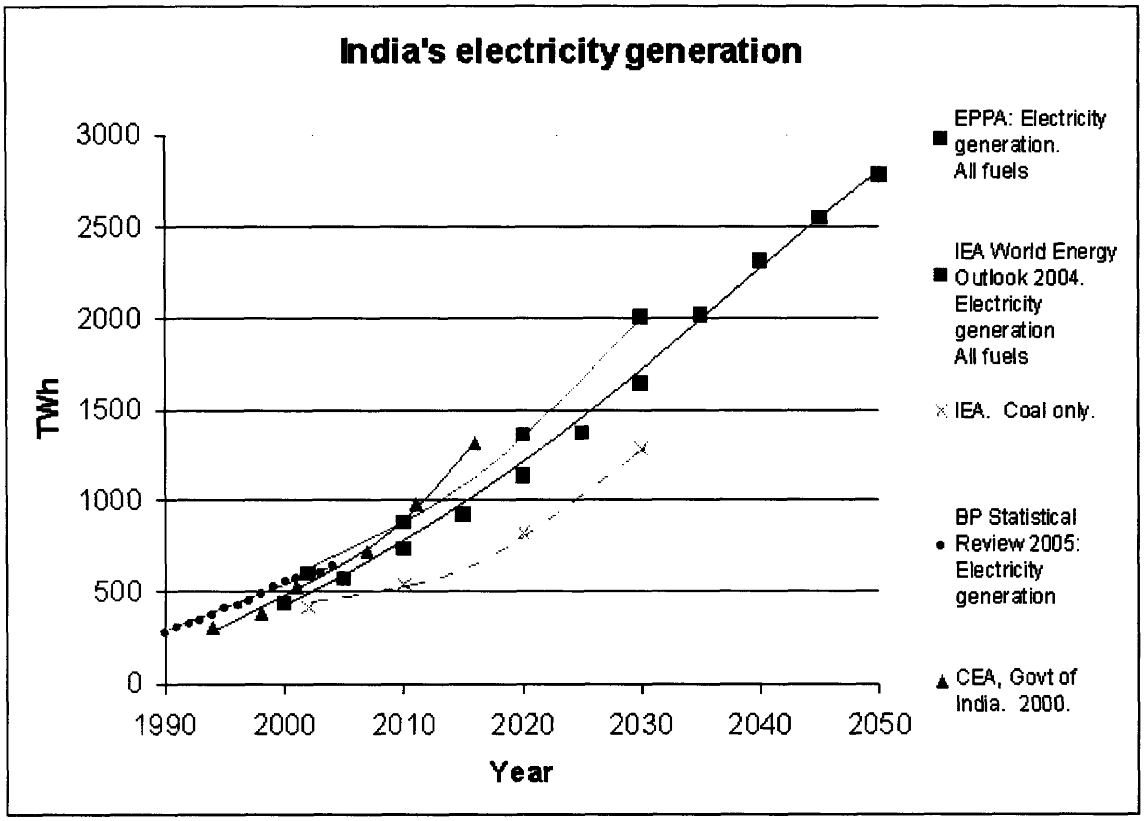


India's electricity generation is projected to increase due to economic growth and governmental electrification plans. Figure 8 below shows projections from various sources. The IEA estimates that India's installed capacity will grow at 4.3%/year and that its electricity generation will grow at 4.9%/year between 2002 and 2010. Actual growth of electricity generation was 2.8% from 2002 to 2003 and 6.6%

[21] Central Electricity Authority (CEA), Ministry of Power, Government of India. Public Electricity Supply – All India Statistics (03-04) –General Review 2005. New Delhi, India. 2005.
[22] Ministry of Power, Government of India. "Installed capacity of power stations on 31.12.2005." Online: http://powermin.nic.in/generation/generation_state_wise.htm. Accessed: April 2006.
[23] The value given for installed wind capacity in the graph is lower as it is an earlier figure. The 3,000 MW is an updated figure.
Ministry of Nonconventional Energy Sources, Government of India. "2005-2006 Annual Report,Wind Energy." Online: http://mnes.nic.in/annualreport/2003_2004_English/ch5_pg1.htm. Accessed: August 2006.
[24] PowerLine Magazine. "Cogeneration". Delhi, India. December 2004.
[25] Ibid. "Installed capacity". Delhi, India. December 2004. 114,740 MW installed capacity
[26] IEA. "Selected 2002 indicators for India."

from 2003 to 2004. IEA forecasts that coal-based installed capacity and power generation will grow at 2.6%/year and 3.1%/year respectively between 2002 and 2010. Coal-based power generation has grown at an average of 6% from 2002 to 2004.[27] These growth rates may not be sufficient to support a projected economic growth rate of 7%, which is greater than the rates for installed capacity and electricity generation.

Figure 8: India's forecasted electricity generation



[28]

Figure 8 shows the India's historical electricity generation up to 2004 and its projected generation to 2050. Once again, the Indian government's projections are the most optimistic. The other projections are less so as they may not take into account Indian government initiatives. The Indian government has formulated and ratified new policies, which will significantly alter the existing system and are important to understand when evaluating future energy growth within India. If the goals included in this policy are realized, the power generation will grow at a higher rate than that shown here. The policy and goals will be discussed in the next section.

[27] IEA, OECD. World Energy Outlook 2004. Paris. 2004. Online: www.iea.org.
BP. "BP Statistical Review of World Energy June 2005."
Data for power generation: The Energy and Resources Institute (TERI). TERI Energy Data Directory & Yearbook (TEDDY) 2003/2004. Rajkamal Electric Press, New Delhi, India. 2004.
[28] EPPA data given in EJ and converted using EPPA conversion factor of 1 EJ = 277.7 TWh.
IEA and BP data given in TWh.

The Effect of Energy Policy in India

Historically, the Indian electricity sector has been under central and state government ownership. Current policy has shifted this focus to open up the electricity sector to the private sector through unbundling and deregulation. The government plans to provide electricity to many more people and to provide better quality service to those who have access to electricity.

When India achieved independence in 1947 there were 1,300 MW of installed electrical capacity. The government soon initiated five year plans to build up the economy and infrastructure within the country. The private sector installed much of the infrastructure until a nationalization policy took hold in the 1970's.

Many national institutions were formed as a result of the nationalization policy. A large majority of the coal mines were nationalized to form the public sector undertaking (PSU) titled Coal India Ltd (CIL). The National Thermal Power Corporation (NTPC) was established as the central utility charged with constructing and operating thermal power plants. Bharat Heavy Electricals Limited (BHEL) became the national boiler and turbine manufacturer with the ability to do turn-key power projects. New capacity installation was also done by the State Electricity Boards (SEB). The vertically integrated state utilities controlled generation, transmission, and distribution within each state. This created an opportunity for the state governments to introduce subsidies for political gain. This resulted in low tariffs or even free power for agricultural users, who were cross-subsidized by the tariffs charged to commercial and industrial users. The cost of power was not recovered from residential consumers. Furthermore, many users simply connected a line to the grid to steal power. In 2003, Chhattisgarh was the only state to recover the full cost of electricity. Jammu and Kashmir was the worst performing state, collecting only 25.3% of the cost of supply. The average recovery was 75% in 2003.[29] By not recovering the full cost of supply, the SEBs found themselves deeply indebted to the central government financing institution.

The central government-mandated accounting practice led to inefficient generating plants. Revenue was assigned to the generation companies by the SEBs on a cost-plus model—the cost of electricity plus a specified rate of return. This did not give inherent financial incentives to increase efficiencies of generating plants.

This led to technical difficulties in generation as well as high line losses in the transmission and distribution lines. Power plants were old and deteriorating and did not incorporate new technologies—resulting in very inefficient plants. Many plants did not have online monitoring systems, used to monitor the performance of the power plants.

The fuel choice and technology choice for new plants were greatly influenced by the availability and ease of establishing fuel linkages. Coal was the fuel most chosen due to the country's large coal resources. When coal linkages were difficult to establish due to rail congestion and large distances from the source, imported coal, natural gas, and other fuels were used. Nuclear power plants are built by the Ministry of Atomic Energy. Hydro plants have been built mainly in the east and northeast. The growth of hydro plants began to slow in the 90's due to the long licensing process and the difficulty of acquiring land and water rights.

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[29] TERI. TEDDY.

These difficulties led to significant shortfalls in electricity production. In 1991 there was a 7% shortfall in energy production and an 18% deficit in peak capacity.[30] Furthermore, the power that was delivered was not always of a good quality, which could damage electrical equipment.

Electricity Act of 1991

These problems continued until the 1990's when a series of reforms was undertaken. The Electricity Act of 1991 opened up the electricity sector to private investment, including foreign investment in generation, providing more capital for capacity additions. A debt to equity structure of 4:1 was allowed to facilitate private ownership (as long as the private owner contributed 11% of the cost of the project). A 16% rate of return on equity (RoE) was assured for private projects with a plant load factor of at least 68.5% (the RoE increases up to 30% for higher PLFs). Import of equipment was permitted and the customs duty for said equipment was reduced to 20%.

The Act also enabled industrial and commercial consumers to address their power problems by allowing them to more easily build captive power plants. Captive power plants grew from 11.5% of installed capacity in 1991 to 16% (18.4/116 GW) of installed capacity in 2002-03.[31] This trend was especially pronounced in Gujarat, a state with many industrial customers. Captive power plants (all fuels) in Gujarat increased from 12.2% of the state's installed capacity in 1991 to 20.7% in 2000. Fuel choices were once again based on availability and price. 46% of independent power projects (IPPs) are steam-based and 39% is diesel-based; the preferred fuels are natural gas and naphtha, followed by oil, coal, lignite, and bagasse plants. IPPs were more likely than the state and central government sectors to source equipment from outside the central government's Bharat Heavy Electricals Limited (BHEL).[32]

In the late 1990's the focus shifted slightly from large government institutions to private sector development. A privatization policy was undertaken by the central government. The Ministry of Disinvestment was created to sell off large public sector undertakings (PSUs). (The plan has not been successful, however, as many citizens' groups have protested the selling of profitable PSUs.) At the same time, the World Bank initiated stricter requirements for funding power projects. The requirements supported unbundling of state-owned electricity boards. With assistance from the World Bank, Orissa became the first Indian (and south-east Asian) state to separate its SEB into separate generation, transmission, and distribution companies in 1996.

Electricity Act of 1998

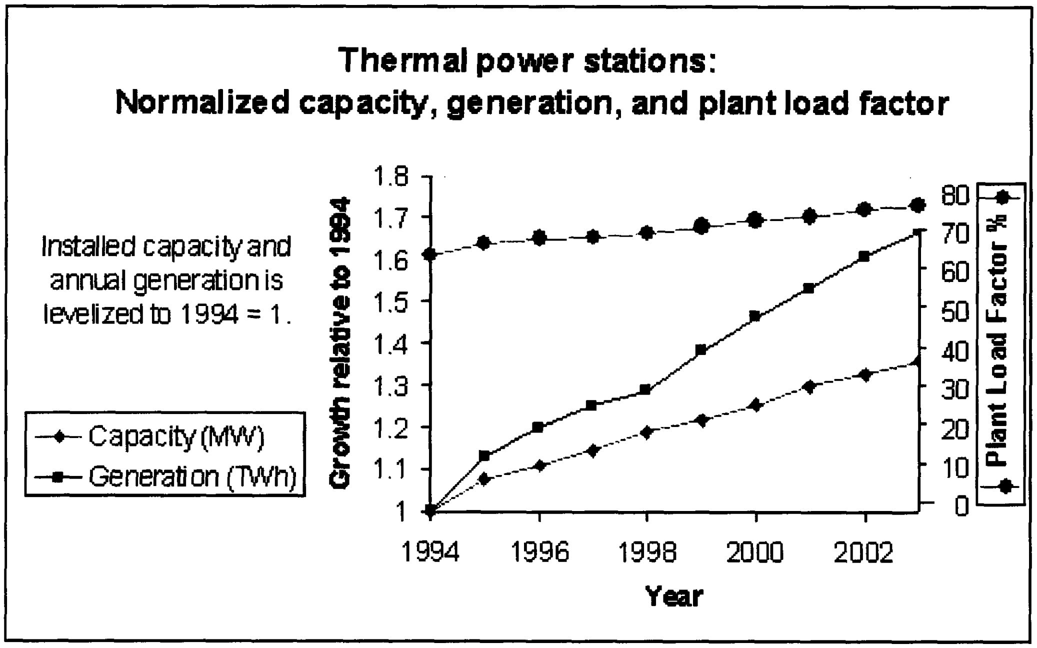
The Act of 1991 focused on opening the sector to private generation and investment, but not on the structure of the existing SEBs. The Electricity Act of 1998, titled the Electricity Regulatory Commissions Act, more directly addressed the regulatory structure. It created a Central Electricity Regulatory Commission (CERC) and State Electricity Regulatory Commissions (SERC). The mandate of the independent ERCs was to regulate tariffs the utilities charged the consumers and to adjudicate disputes. It did not address the low efficiency of power plants, financial problems in the utilities partly based on subsidies, and collection of tariffs for all electricity used. On its own, the Act did not solve the fundamental problems in the sector.

A few positive trends emerged partially from these early legislative initiatives, but more significantly from initiatives by Indian and foreign organizations. The largest generation company, the central

[30] Shukla, PR, Thomas C. Heller, David G. Victor, Debashish Biswas, Tirthankar Nag, and Amee Yajnik. Electricity Reforms in India: Firm Choices and Emerging Generation Markets. Tata McGraw Hill. September 2004.
[31] TERI. TEDDY.
[32] Shukla, PR. Electricity Reforms in India.

government National Thermal Power Corporation (NTPC) developed the Center for Power Efficiency and Environmental Protection (CenPEEP) with support from USAID. It had great success in improving efficiencies of centrally operated plants—the average plant load factor of centrally-owned thermal plants increased from 70.4% in 1997-98 to 74.3% in 2001-02 (about equal to that of privately-owned plants). CenPEEP began to offer engineering services to the state plants (which had some of the lowest efficiency rates): the average plant load factor of state-owned thermal plants increased from 60.9% in 1997-98 to 67% in 2001-02. Some of the state-owned plants that were inefficient and unprofitable were handed over to NTPC for operation. The result of these improvements is shown in figure 9. The country's electrical generation grew by a larger percentage than its installed electricity capacity, reflecting increased usage and efficiency of the existing plants.

Figure 9: Growth of thermal power in India[33]



The average plant load factor (shown in green) increased from 60% in 1994 to 73% in 2003. The installed generating capacity and total thermal-based power generation are normalized to 1 in 1994 to be able to compare their growth. This shows that electricity generation grew faster than the installed generating capacity, i.e., the plant operators were able to get more electricity out per MW of installed capacity.

The initial reforms did not relieve the consumer subsidies. The gross subsidy per unit of electricity generated steadily increased from 0.75 Rupees / kWh in 1997 to 1.27 Rupees / kWh in 2002. Gross subsidies to domestic and agricultural consumers increased 188% and 95% respectively between 1997 and 2002.[34] To combat these problems, more holistic and sector-wide planning and operational changes were necessary.

Data from India's parliament, the Lok Sabha, shows that the average cost of electricity generated in 2002-2003 period was 271 paise/kWh (table 8). The average power tariffs collected are also shown in table 8

[33] Central Electricity Authority (CEA), Ministry of Power, Government of India. Performance Review of Thermal Power Stations, 2003-04. New Delhi, India. 2004.
[34] Shukla, PR. Electricity Reforms in India.

below. The values are converted into dollars using the US Federal Reserve exchange rate (2 January 2003) of 48.05 rupees = 1$.[35]

Table 8: Cost of electricity supply and tariffs supplied to consumers in India[36]

State average cost of power supply in India (2002-2003)

	Paise / kWh	US cents / kWh
National average	271	5.6
Minimum	149	3.1
Maximum	390	8.1

Average power tariff paid by consumer sector in India (1999-2000)

	Paise / kWh	US cents / kWh
Domestic	149	3.1
Commercial	354	7.4
Agriculture	25	0.5
Industrial	350	7.3

Electricity Act of 2003

The Electricity Act of 2003 replaced all previous electricity sector legislation: its goal was a more comprehensive reform of the power sector. PR Shukla, professor at the Indian Institute of Management Ahmedabad, states that the principal feature of the legislation was to mandate open access to the electrical grid. It allows for multiple transmission and distribution networks, and promotes the commissioning of captive power plants. It also allows for trading and third-party sale of electricity. This enables wheeling of electricity whereby captive power plants can not be prevented from selling excess power to the grid. New gas and coal plants are freed from most of the lengthy, licensing procedures that were previously required (although hydroelectric projects still require licensing).

The Act outlines policies that serve to increase the financial health of the sector so that it is able to attract funds from capital markets. This means that the costs of electricity generation and distribution must be realized. This requires mandatory metering and phasing out of cross-subsidized power. All subsidies would have to come out of the state government's budget. The Act mandates that all vertically integrated state electricity boards be unbundled into separate generation, transmission, and distribution companies.

[35] US Federal Reserve, . "India -- Spot Exchange Rate, Rupees/Us$". Online: http://www.federalreserve.gov/releases/H10/hist/dat00_in.txt. Accessed: 15 May 2005. A Paise is 1/100 of an Indian Rupee.

[36] IndiaStat online statistical database. "Electricity Supply." India. Accessed: March 2006. Online: www.indiastat.com.
State average cost of power supply original source is: Lok Sabha, Unstarred Question No. 2800, dated 17.8.2004. Average power tariff paid original source is: Lok Sabha Unstarred Question No.1015, dated 1.3.2001.
100 Paise is equal to 1 Indian Rupee.

As of February 2006, eight of 28 states have unbundled while two have privatized distribution (Delhi and Orissa).[37] The private sector was granted open access to generation, distribution, and captive power.

In addition to establishing policies, the National Electricity Policy offered more specific goals for planning purposes:

- Double installed capacity from 100,000 MW in 2002 to 200,000 MW by 2012
- Generate sufficient power by 2012 to meet all demand plus a spinning reserve of at least 5% above the demand
- Provide availability of over 1,000 kWh of per capita electricity by 2012
- Add 10,000 MW of renewable power capacity by the year 2012
- All consumers should be metered by 2007
- Provide access to electricity to all villages by 2007 and to all households by 2012.
- Improve reliability by providing uninterrupted supply of electricity 24 hours a day
- Increase generating capacity to mitigate energy shortage
- The maximum subsidy offered to any group should be 50% of the cost of supply by 2012

The final two points are a significant challenge considering that the government wants to increase the number of consumers while increasing supply to overcome the current shortage. Table 9 below shows that the unmet energy demand is 7.6% and the peak demand deficit is 10%.

Table 9: Power shortage (April-December 2005)[38]

	Demand	Met	Surplus (deficit)
Energy	465,200 GWh	429,800 GWh	(7.6)%
Peak Demand	89,500 MW	80,600 MW	(10.0)%

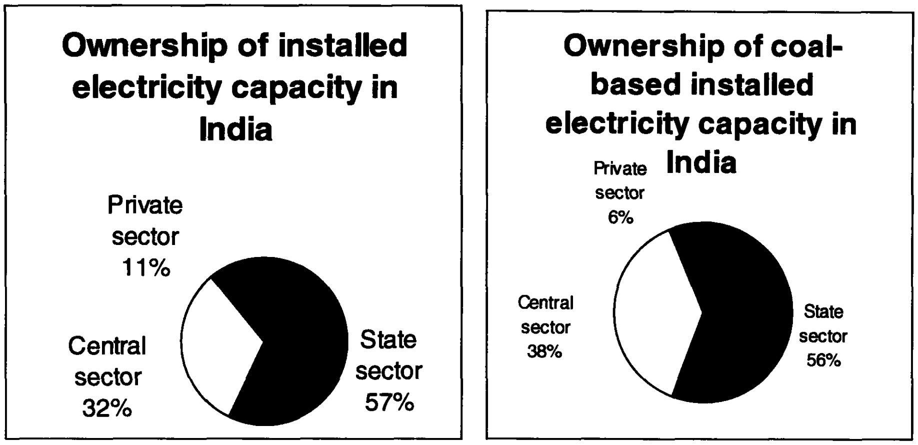
These shortfalls are more significant in certain regions of the country. Madhya Pradesh is reported to have the highest energy deficit of 15.4% and the highest peak demand deficit of 21.6% in 2001-02. The best performing of the large states is Orissa with a power deficit of 0.1% and Haryana with a peak demand deficit 3.3%.[39]

Power Sector Planning

The power sector in India has always been considered the joint responsibility of the state and central governments. In the last several decades, the largest share of generation was done by the state sector. However, in recent years an increasing share of new capacity additions have been done by the public sector utilities (PSUs) such as the National Thermal Power Corporation, the National Hydro Power Corporation, and the Ministry of Atomic Energy. Figure 10 shows the breakdown of electricity generation by corresponding sector in February 2005.

[37] Ministry of Power, Government of India. "Power Sector Reforms". New Delhi, India. Online: http://powermin.nic.in/indian_electricity_scenario/reforms_introduction.htm. Accessed February 2006.
[38] Ministry of Power, Government of India. "Installed capacity of power stations on 31.12.2005". Accessed: March 2006. Online: http://powermin.nic.in/JSP_SERVLETS/internal.jsp.
[39] TERI. TEDDY.

Figure 10: Ownership of all and coal-based electricity capacity in India[40]



The electricity sector remains a planned sector. The Central Electricity Agency (CEA) develops plans for new capacity additions. The plans are specific to the point of including fuel mix, size, and location of plants. This serves as a recommendation for the central, state, and private sectors, but the CEA does not have the power to actually carry out the plans. Table 10 below illustrates the CEA proposed and actual additions for previous years.

Table 10: Indian government targets for installed electricity capacity additions[41]

Target capacity addition (*% of target achieved*) between 1997-1998 to 2001-2002

	Central		**State**		**Private**		**Total**	
Thermal	7,574	*41%*	4,933	*112%*	17,038	*29%*	29,545	*46%*
Hydro	3,455	*16%*	5,815	*67%*	550	*16%*	9,820	*46%*
Nuclear	880	*100%*	0	-	0	-	880	*100%*
Total	11,909	*38%*	10,748	*88%*	17,588	*29%*	40,245	*47%*

Target capacity addition (*% of target achieved by 2005*) between 2001-02 - 2006-07

	Central	**State**	**Private**	**Total**	
Thermal	12,790	6,676	5,951	25,417	*26%*
Hydro	8,742	4,481	1,170	14,393	*35%*
Nuclear	1,300	0	0	1,300	*0%*
Total	22,832	11,157	7,121	41,110	*24%*

The table shows that only 47% of planned capacity additions were realized in the 9th plan. Similarly, the goals for the 10th plan do not look realizable. The Ministry of Power has stated that the plans for the private sector were overly ambitious. Some private-sector projects were not implemented due to uncertainty and risks related to receipt of payments for power generated. Power purchase agreements are

[40] CEA. Thermal Power Stations.

[41] Central Electricity Authority (CEA), Ministry of Power, Government of India. Sixteenth Electric Power Survey of India. New Delhi, India. 2003.
TERI. TEDDY.

often renegotiated by the SEBs after the contracts have been signed. Additional difficulties include delays in land acquisition and environmental clearances, unresolved issues relating to fuel linkages, and problems relating to dealing with local populations. Sushil Maroo, director of Jindal Steel and Power, estimates that it takes 7 to 8 years from planning a power project to implementation.

As with the private sector, the central sector has not met its goals. However, in absolute terms, the central sector has added about twice as much thermal capacity as the state sector. NTPC, with an installed capacity of 22,749 MW, has stated an interest in continuing this trend.[42] Chandan Roy, director of operations of NTPC, has stated that NTPC plans to double the annual capacity additions for which it is responsible: adding 20,000 MW of capacity between 2002 and 2012. Additionally, it plans to expand from coal-based and gas-based plants into hydro and possibly nuclear plant generation. It has started a large R&D center to facilitate its goals.[43]

Along with the expansion of NTPC is the expansion of BHEL. BHEL plans to expand manufacturing capabilities and increase research and development expenditures five-fold.

Reforms

The reforms made by the Indian government that began in the 1990s reflect a realization that there are large problems in the sector. More accurate data have been released by the government that shows the large supply-demand gaps, indicating the level of underdevelopment within the sector. The government would like to fix these problems while also dealing with a larger problem: the level of socioeconomic stratification within the country. Providing electricity to the poor and rural people is one way to raise their socioeconomic level.

The two goals of reforming the sector while increasing the supply for the impoverished both require increasing the installed electricity capacity. Based on past growth, this means new coal plants. The next chapter will discuss the coal supply and the quality of coal in India. This is important in understanding the role of coal in the Indian power sector in the future.

[42] Venkataraman, R and Prajakta Pradhan. "India Infoline". Interview with C.P. Jain, Chairman & Managing Director of NTPC. 02 March 2005. New Delhi, India Online: http://www.indiainfoline.com/view/020305.html.

[43] "NTPC's ambitious capacity addition programme." The Hindu. 04 April 2003. New Delhi, India. Online: http://www.hinduonnet.com/2003/04/05/stories/2003040502091600.htm.

3. COAL

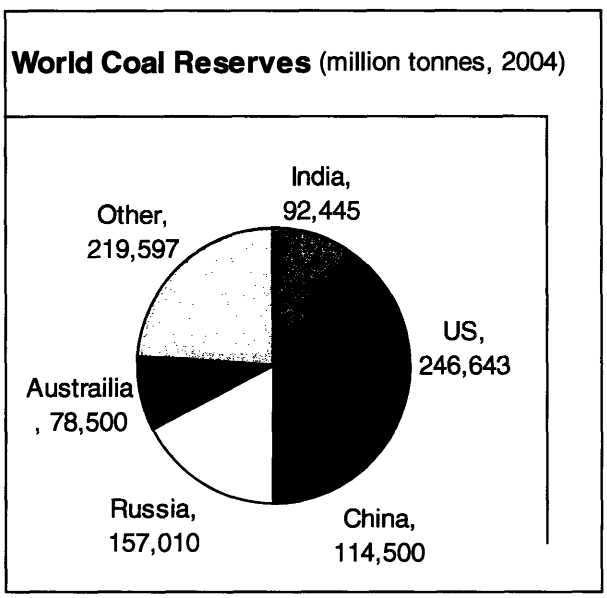
Coal is the largest fuel source for power generation in India. However, policy and planning for the coal sector are quite different from that for the power sector since responsibility for oversight of coal mining, production, and transportation falls under the Ministry of Coal (and partially the Ministry of Railways). For this reason, the coal sector has developed differently from the power sector. The reforms outlined in the previous chapter do not affect the supply of coal to the power plants. These reforms signify an increased demand for coal for power generation, but do not ensure an increased supply of coal from the producers. This has important implications related to coal-based power plants.

This chapter will look at the supply of coal to the coal plants to show the balance of supply and demand. Government policies will then be discussed to understand how the current coal production levels could change based on drivers by the government. Finally the unique properties of Indian coal will be described.

Reserves

Almost 75% of the world's coal reserves are concentrated in five countries as shown in figure 11. India is shown to have the fourth largest coal reserves after the US, China, and the Russian Federation (which does not include independent former Soviet Union countries).

Figure 11: World coal reserves[44]



Ninety percent of India's coal reserves are located in the northeast section of the country as shown in figure 12. Unfortunately, many of these areas are also some of the poorest areas in India and are struggling against the naxalite Maoist insurgency. Indian Prime Minister Singh has issued a statement saying that this may pose one of the largest threats to India's energy security. Thus far, Maoist rebels

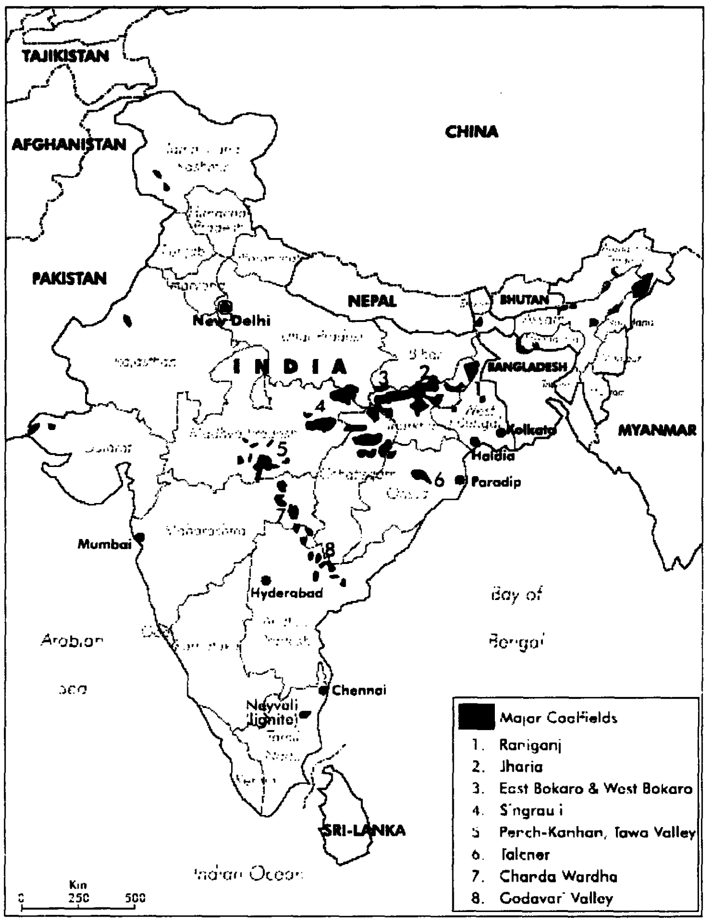
[44] BP. "BP Statistical Review of World Energy June 2005."

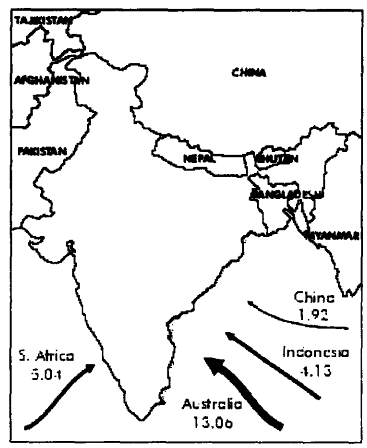
have not made significant attacks on coal mining equipment or supply infrastructure. There are no signs that disruptions will increase, but if the fighting increases, this could cause delays in production and in mining new coal blocks.

Areas in the south and west have ready access to coal imports shipped from Australia, Indonesia, China, and South Africa.

Figure 12: Coalfields in India[45]

Figure 7
Major Coalfields and Mining Centres





Source: Coal Information, IEA/OECD Paris 2001

BP estimates that India has 92 billion tonnes of coal reserves in these mines. However, not all of this reserve is economically extractable. The Energy and Resources Institute (TERI) estimates that only 21% of the total resources or 52 billion tonnes can be extracted under current economic conditions.

Table 11: Coal resources in India[46]

	Proved		Indicated		Inferred		Total	Economically extractable	
Total Billion tonnes	93	+	117	+	38	=	248	52	(21% of total resources)

[45] IEA, OECD. Coal Information. Paris. 2001.
[46] Chand, SK. "Can domestic coal continue to remain the king?" TERI Newswire. 1-15 April 2005. 11(7).
* includes Singareni Collieries Company Ltd, Tata Iron and Steel Company Ltd, Indian Iron and Steel Company Ltd, other captive and non-captive blocks etc.

Coal Consumption and Production

India has the fourth largest coal resources in the world, but is the third largest consumer of coal after China and the United States. India would be able to sustain current production levels for about 240 years based on its reserves.

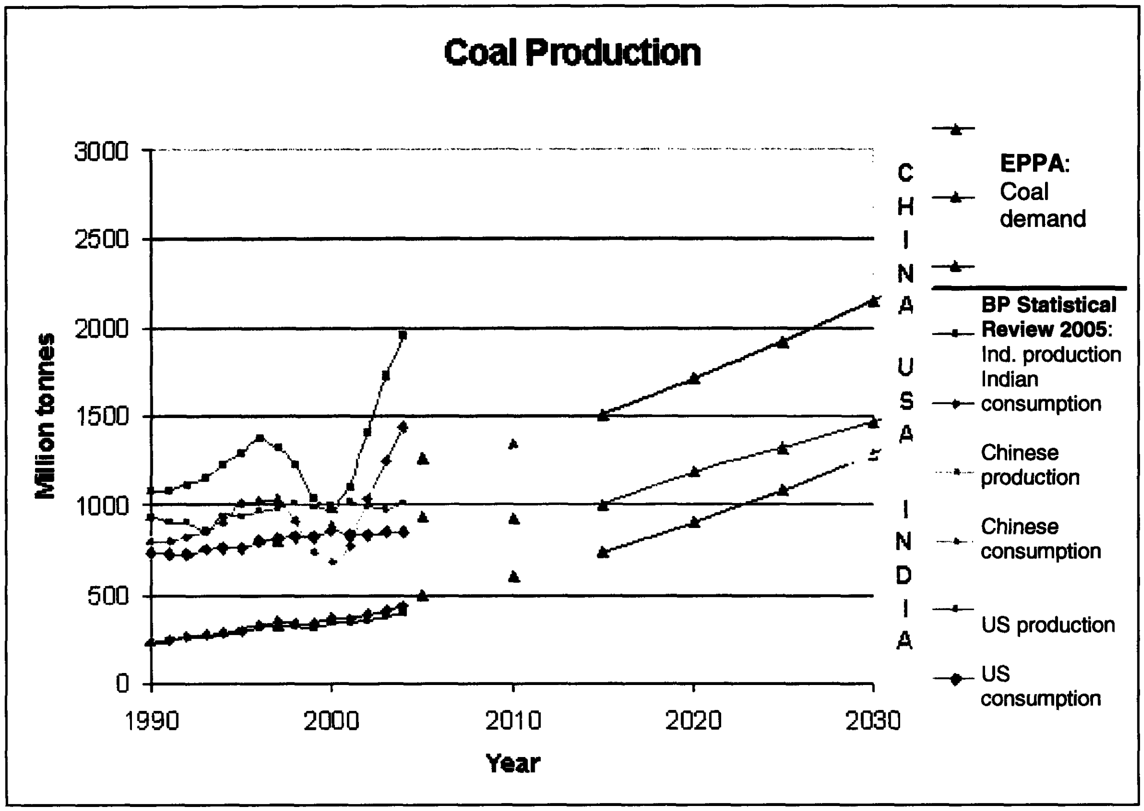
Table 12: Coal data for India, the US, China, and the Russian Federation[47]

	India	US	China	Russian Fed.
Coal Consumption Million tonnes	437	1005	1,895	232
Coal Production Million tonnes	403	1,008	1,956	280
Proven Coal Reserves Billion tons	92	247	115	157
Reserves/Production Ratio Years	237	254	87	710

India produced 403 million tonnes and consumed 437 million tonnes of coal in 2004 (table 12). These numbers are expected to increase. Figure 13 below shows how these numbers will increase with the projected coal production up to 2030. Coal production in India is forecasted to double from 2005 to 2020. Coal production in the US is projected to increase by 40% from 2005 to 2020. China's recent growth in coal production was not taken into account in the EPPA model—resulting in lower than expected production levels.

[47] BP Data for 2004. IEA. 2002.
Both include coking, bituminous, anthracite, sub-bituminous, and lignite coals.

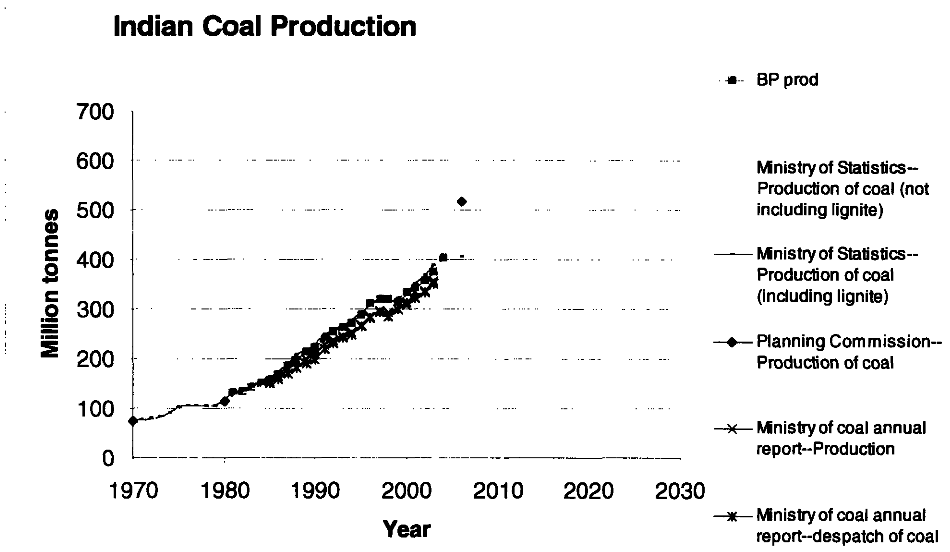
Figure 13: Coal production forecasts for China, the US, and India[48]

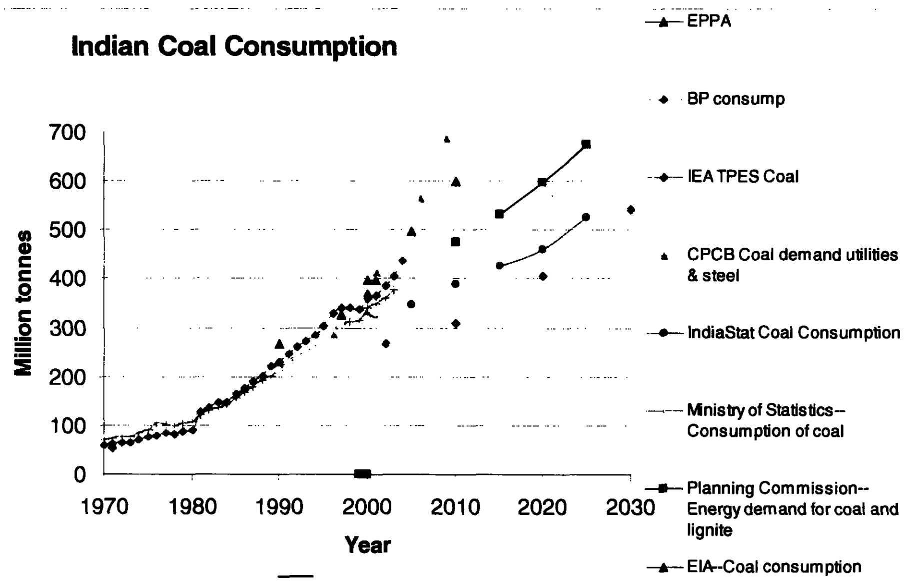


Beyond what is shown in figure 14, there are many estimates for how much coal will be consumed in India in the future. Figure 15 below shows the historical growth in coal production and consumption as well as multiple projections for future coal consumption. The Indian government's Central Pollution Control Board projects the highest increase in coal consumption while the IEA projects the lowest increase in coal consumption. The more conservative estimates seem to be the most believable. Many of the models rely on economic growth projections. While the Indian economy has grown significantly, the rate of electricity generated has not grown as fast due to lack of investment. This may not be taken into account in the models.

[48] MIT's Anthropogenic Emissions and Policy Analysis (EPPA) Model. Based on 1997 data
BP Data from 2004.

Figure 14: Indian coal production and consumption forecasts[49]





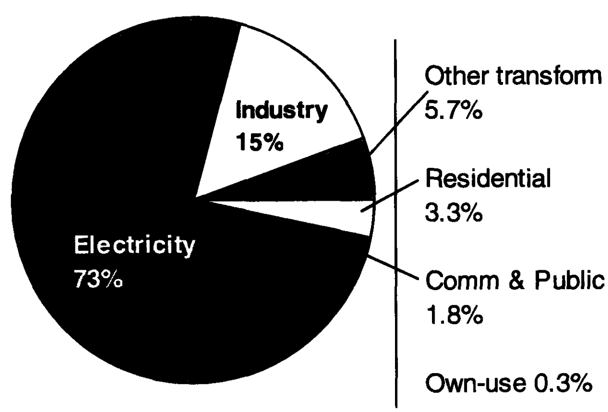
[49] **EPPA**: Coal Demand: Based on 1997 IEA data received in units of EJ. Converted to tonnes using an energy content of 26 GJ/tonne (McFarland). BAU carbon policy, ref gas price, limited nuclear expansion.
IEA: TPES: Outlook 2004. Data given in toe. No conversion factor given, I used 1.5 tonnes/TOE.
Central Pollution Control Board (Govt of India: Coal demand: Does not state where data comes from. Given in tonnes (June 2000)
IndiaStat: Coal Consumption: Online database. (Oct 2003). Given in tonnes. Source is Intl Conference on Thermal Power Generation.
Ministry of Statistics (GoI): Coal consumption / Production: Data recorded in tonnes, coming from the **Ministry of Coal**, which refers to the mass as offtake (http://coal.nic.in/cpddoc.htm). Sliding energy content scale used for conversion to joules.
Planning Commission (GoI): Coal production: 10th year plan. Coal demand. Data given in tonnes.
EIA: Coal consumption: Converted from short tons by 2240 tonnes / 2000 short tons. This assumes that Indian coal use will increase by 2.3% per year from 2001 (66 GW) to 2025. Meaning India will add 57 GW of coal generation by 2025. (Although according to CEA, India has 62 GW coal as of February 2005.)

Coal consumption is forecasted to increase from its 2004 production level of 400 million tonnes. In the previous decades coal production has grown at about 6% annually, slowing down to 5% after 1997.[50] Currently India consumes more coal than it produces—making it a net importer. Historically, India has been a net exporter of coal. High demand and difficulties in fuel supply links (overcapacity of railroads and inefficiently designed linkages) have resulted in India being a net importer of coal.[51] The share of imported coal is expected to increase due to these limitations.

The Energy and Resources Institute (TERI), a New Delhi-based research institute, estimates that the annual output of Indian mines is projected to be limited to 450-500 million tonnes of coal per year (out of 50 billion tonnes of economically extractable reserves).[52] The consumption of coal is forecast to surpass this amount within 15 years. This would result in coal shortages. The solution to this is imported coal, which is desirable to generation companies as the quality of imported coal is generally higher than that of domestic coal. The downside is that it is more expensive than coal sold at the mine mouth. The Indian government has tried to hedge the risk that consumption will continue to increase faster than production in India by investing in Australian coal mines and securing a coal supply outside of the country.

A large share of the imported coal is sent to power stations along in the coast in major load centers. The majority of coal consumption in India is for power production, followed by industry and residential, as shown in figure 14. The largest use of coal in industry is for steel production, followed by cement production.[53]

Figure 15: Sector-wise consumption of coal in India[54]



[50] Chowdhary, S.K. "Coal in India" World Energy Council. London. Accessed: June 2006. Online: http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/2_1_20.asp.
[51] Sarkar, S K and S K Chand. "Start power reforms from the pit". The Economic Times. New Delhi, India. 17 May 2003.
[52] Chand, S K. "Can domestic coal continue to remain the king?"
[53] TERI. TEDDY. CCO (Coal Controller's Organization). Coal Directory of India (various years). Kolkata: CCO, Ministry of Coal, Government of India
[54] IEA. "Selected 2002 indicators for India."

Production Policy

The Electricity Act of 2003 does not address the aforementioned problems in the coal supply sector. Crucial issues such as fuel policy, transport policy, and finance policy are not included as their jurisdiction lies outside of the Ministry of Power (MoP) in the Ministry of Coal (MoC) and Ministry of Railways (MoR).

The non-integration of these ministries is significant as the Ministry of Coal directly oversees the largest producer of coal in the country: Coal India Limited (CIL). CIL was formed in 1975 by nationalizing many private sector companies. A few companies, such as Singareni Collieries remained independent. Neyvelli Lignite Corporation (NLC) was formed to mine the majority of lignite mines. CIL and NLC report directly to the Ministry of Coal. They control all reserves not under direct ownership of the few private companies.

Policy changes were recently instituted by the MoC that opened mine ownership to the private sector and to pithead coal plants.[55] Companies may apply directly to CIL for such mines. This process has been highly criticized due to the lengthy procedures involved. Additionally the mines that are licensed are criticized for being the least profitable: difficult to mine with low quality coal.

Many power generating companies are upset with the coal that is delivered to them from CIL. Under current law, CIL is no longer responsible for the coal once loaded upon rail cars. Power companies complain that the delivered coal is not the actual quantity paid for and that it is of lower quality than ordered. About 90% of coal is purchased with purchasing contracts, while 10% is sold on the spot market.

Additional inefficiencies in the system are present due to the suboptimal transport linkages and there are significant delays on the over-crowded railway network. 56% of total coal production is transported by rail, followed by 23% transported by a merry-go-round system.[56] 21% of plants are located further than 1000 km from the coal mines.[57] The furthest plants have begun to source their coal from outside the country rather than purchasing from CIL. An alternative to sourcing coal from outside the country or transporting the coal are mine mouth (pithead) power plants; which entail the transport of electricity as opposed to the coal. 37% of coal plants are currently pithead power plants. NTPC envisions constructing super thermal power stations of 2,000-4,000 MW capacity at the mine mouth. Still larger sizes are limited due to the environmental impact.

The shortage of coal to the plants is so drastic that the Ministry of Power has *asked* power stations to import coal. Coal-based power plants are supposed to keep a 15-day supply of coal on site. In June 2005, 22 of the 75 coal plants had stocks of less than 7 days.[58]

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[55] Pithead coal plants are those power plants located right on the mine mouth.
[56] Chowdhary, S.K. "Coal in India". A merry-go-round system are small transport systems that carry the coal from the mine mouth to a point source located close to the mine. These are dedicated rail linkages.
[57] Ibid.
[58] Kumar, Manoj. "Power Ministry SOS to PM on coal shortage". Tribune News Service. Chandigarh, India. 10 June 2005. Online: http://www.tribuneindia.com/2005/20050610/biz.htm#1.

Coal quality

Indian coal is primarily sub-bituminous, followed by bituminous and lignite. Most mining is done open-pit on thick seams near the surface. Indian coal is different from US coal in that it has a higher ash content, lower sulfur content, and lower heating caloric value. Table 13 gives characteristics for a representative Indian and US coal:

Table 13: Comparison (Ultimate analysis) of Indian and US coal[59]

	N. Karanpura Indian coal	N. Karanpura Washed Coal	Kentucky US Coal
Ultimate Analysis (as-received, wt%)			
Moisture	8.7	7.4	2.3
Carbon	40.3	46.0	71
Hydrogen	3.2	3.6	5.1
Nitrogen	0.9	1.0	1.5
Sulfur	0.5	0.5	2.3
Ash	38.2	33.0	9.8
Oxygen (by difference)	8.2	8.6	8
Total	100%	100%	100%
Proximate Analysis (as-received, wt%)			
Moisture	8.69	7.44	
Ash	38.22	32.97	
Volatile Matter	23.76	26.71	
Fixed Carbon (by difference)	29.33	32.88	
Total	100.00	100.00	
Net Calorific Value, (kcal/kg)	4,180		7,022
Gross Calorific Value, (kcal/kg)	3,692	4,228	
Coal per unit of electricity (kg/kWh)	0.70		0.36
Ash Fusion Temperature (°C)	1,500	1,500	

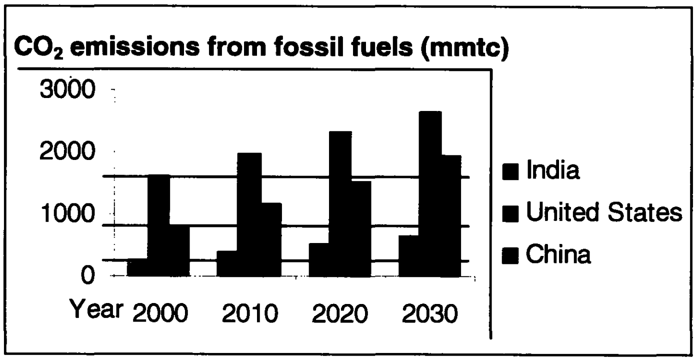
The sulfur content is lower compared to US coals, but the moisture content is higher, especially during the monsoon season. 80% of Indian coals have an ash content between 35 and 50%.[60] Indian coals are described as having positive combustion characteristics. The coal has a high ash fusion temperature (>1,100 °C), meaning that if burned at lower temperatures the ash does not melt. This is beneficial as the slagging (melting) takes heat that could be utilized for power generation and the large quantity of ash is easier to handle in solid form.

The high mineral content and specifically the mullite and quartz present additional difficulties in combustion. These minerals cause erosion of pulverisers, boiler tubes, and ID fans. Additional problems include corrosion, delayed combustion, deposits, fouling and slagging.[61]

[59] Table copied with permission from: Chen, Tan-Ping. "Effects Of Coal Ash Content On Cost Of Generation For IGCC Power Plant." Nexant, Inc. San Francisco, California, USA. 2005.
[60] "Coal in the Energy Supply of India". Coal Industry Advisory Board, International Energy Agency, Organization for Economic Cooperation and Development. Paris. 2002.
[61] Rao, OP. "Coal gasification for sustainable development of the energy sector in India". World Energy Council. New Delhi, India. Online: http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/2_3_28.asp. Accessed: March 2006.

Associated with this consumption is the release of greenhouse gases, primarily CO_2. In 2002, India emitted 1016 million tonnes of CO_2. This is in comparison with US emissions of 5652 million tonnes and China's emissions of 3307 million tonnes of CO_2. All these values are expected to increase as shown in figure 16, but Indian and Chinese emissions are expected to increase at a faster rate—narrowing the gap between their emissions and that of the United States. Projected increases in annual CO2 emissions for the U. S., China and India to 2030 are shown in Figure 16.

Figure 16: Carbon dioxide emissions forecasts for India, the US, and China[62]



India contributes 3.9% of the world's CO_2 (6th largest emitter) but it is estimated that this will increase to 6.2% in 2020. This suggests that India's combustion of fossil fuels will increase faster than that for other countries. The largest point source of emissions is fossil power—representing 29.6% of total emissions (followed by livestock and steel production at 12.6% and 8.8% respectively of total emissions).[63] This means that fossil-based power production is good place to begin carbon emission reduction strategies.[64]

Coal for power generation

In the last few years, India has begun to have a negative trade balance for coal—importing more than exporting. Policies have sought to mitigate this widening demand-supply gap by partially opening up the coal mining sector. However, these reforms are not occurring at the same pace as those for power generation that are stimulating an increased rate of construction of new coal plants.

The unique properties of Indian coal, particularly its high ash content, need to be considered along with the previously mentioned supply gaps in selecting new coal-based power generation technologies. The next chapter will describe the current technology to understand how it fits into this scenario.

[62] EPPA. MIT.
[63] Amit, Garg, M. Kapshe, P.R. Shukla, and Debyani Ghosh. "Large Point Source (lps) Emissions From India: Regional and Sectoral Analysis." Atmospheric Environment 36, no. 2 (2002): 213-224.
[64] Guha, Manoj K. "The Role of Coal in Future Power Generation in India". American Electric Power. Columbus, Ohio, USA. Presented at: Coal and Electricity in India Conference. 22-23 September 2003; New Delhi, India. Online: http://www.iea.org/textbase/work/2003/india/SESS42.PDF.

4. COAL-BASED POWER PLANTS

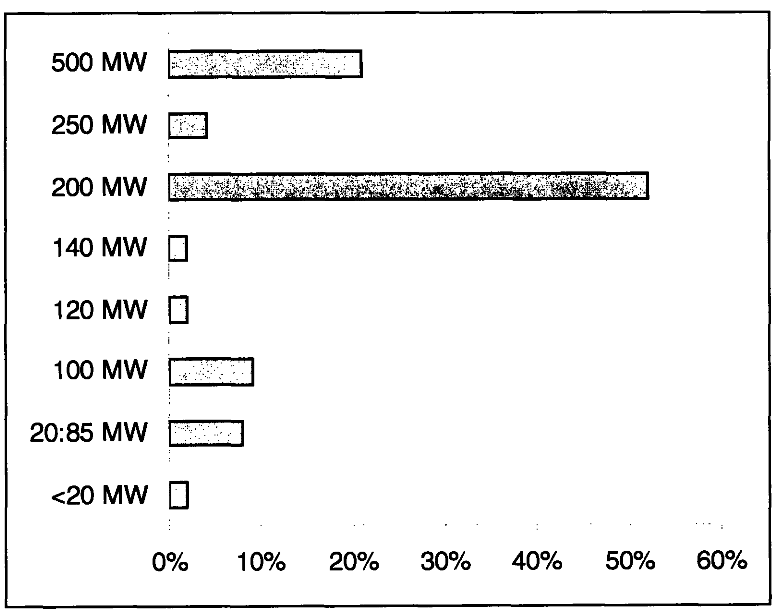
India has 62 GW of installed coal-based power production capacity.[65] The majority of these power plants are pulverized coal combustion plants that operate on a sub-critical steam cycle. The older plants are generally very inefficient, smaller, and located far from the coal mines. Newer plants are more efficient and larger in size with the construction of new super thermal power stations, whose generating capacity is larger than 1,000 MW, now being initiated.

The existing plants will be discussed in this chapter in more detail. This is followed by a case study looking at the procurement for a coal plant with an advanced, supercritical steam cycle. This gives insight into what it would take to move to a more advanced technology, such as ultra-supercritical PC or IGCC in India.

Existing coal plants

India has over 80 utility-sized coal-based power plants, eighteen of which have been constructed between 1994 and 2004, with a total capacity of 5,650MW (33 percent of the total existing capacity).[66] 50% of installed capacity in India is at power plants of 200 MW size. Newer plants are generally built at 500 MW size. Figure 17 shows the share of installed capacity in various sizes of power plants in India. The plants were historically built at set sizes due to BHEL's ability to construct equipment.

Figure 17: Percentage of coal-based installed generating capacity in various sized power plants[67]

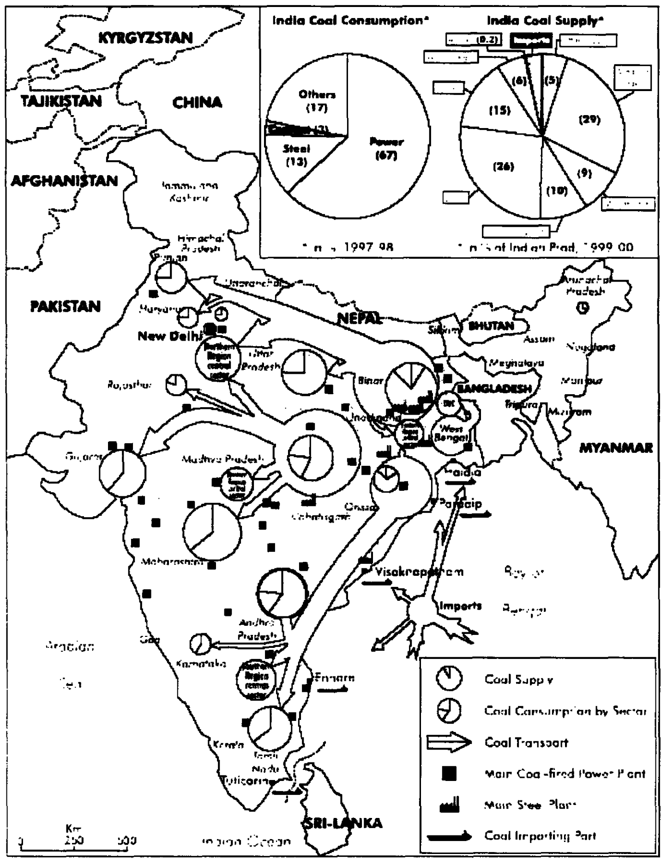


[65] CEA. Thermal Power Stations.
[66] Sathaye, Jayant, Scott Murtishawa, Lynn Pricea, Maurice Lefranc, Joyashree Roy, Harald Winklerd, Randall Spalding-Fecher. ".Multiproject baselines for evaluation of electric power projects". *Energy Policy*. Volume 32 (2004). P. 1303-1317.
[67] CEA. Thermal Power Stations.

Since most reserves are in the east of India, there is a higher concentration of coal-fired plants there than in other regions: 1/3 of the coal-based installed capacity is located in the eastern region. The coal gets transported to the load sectors as shown in the following map.

Figure 18: Coal production and consumption centers in India[68]

Figure 8
Coal Production and Consumption Centres by State and Sector, 1998



Technology

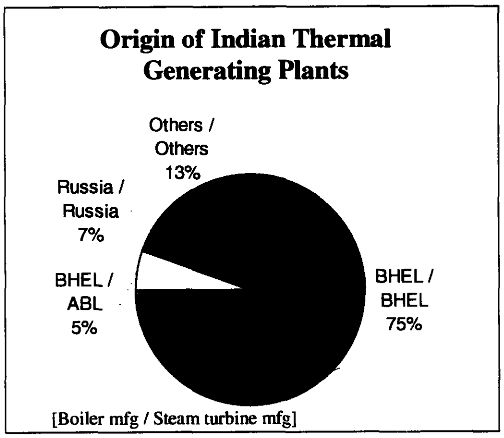
The choice of technologies for coal-based power plants is generally based on experience. Current environmental standards and regulations do not play a large role in technology and fuel decisions as the laws are very general. The majority of electrical plants and all recently installed plants are subcritical pulverized coal (PC) plants. Bubbling fluidized bed combustion (FBC) and circulating FBC are commercially used for burning lower-quality lignite. Pressurized FBC and atmospheric FBCs are also used in specialty applications, such as chemicals production or coal blending with biomass. These all employ a subcritical steam cycle.

[68] IEA, OECD. Coal Information. Paris, 2001. Online: www.iea.org. Data from 1998.

The majority of power plants use equipment manufactured by Bharat Heavy Electricals Limited (BHEL). BHEL can manufacture and build all components in turn-key plants, and is capable of supplying coal boilers up to 500 MW in size as well as FBC boilers up to 125 MW in size.

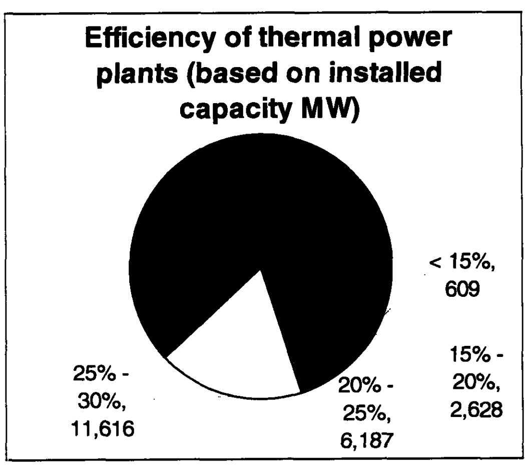
BHEL's original boiler technology is based on a license from Combustion Engineering, Russian-based LMZ, and KWU. Its gas and steam turbines are based on licenses from GE and Siemens. The makeup of boilers and turbines show that BHEL has been the choice of procurement—it offers low cost products, it can provide service as it is completely located in India, and it is connected to the central government. Figure 19 shows how many of the plants were built with BHEL equipment.

Figure 19: Origin of Indian thermal generating plants[69]



Many of the older plants are of Russian-make and of a lower efficiency. Most new plants are BHEL-supplied and have a higher efficiency. Figure 20 shows the installed capacity of (largely subcritical PC) power plants that fall within various efficiency ranges.

Figure 20: Efficiency of thermal power plants[70]



[69] CEA. Thermal Power Stations.
[70] Ibid.

Large multinational original equipment manufacturers (OEMs) have opened operations in India. Siemens, Alstom, GE, and Mitsubishi are all located in India. However, it is very difficult for these companies to compete with BHEL based on capital costs. Levelized costs are another matter as foreign companies manufacturing advanced technologies result in higher efficiencies.

Environmental control

There are some environmental regulations for coal-based power plants. The *Central* Pollution Control Board (CPCB) is charged with drafting the environmental policies that affect coal-based power plants. The *state* Pollution Control Boards (SPCBs) must adopt these standards or more strict ones, and then are charged with enforcing the regulations.

The CPCB rules regulate the particulate emissions, the minimum stack height, cooling water temperature and its effect on seawater temperature, and disposal of ash. Most new plants are required to install electrostatic precipitators.[71] Sulfur and Nitrogen emissions are generally not directly addressed and plants generally do not have equipment installed to control these pollutants. The exception to this is combustion turbines on natural gas fired plants which are purchased with low-NOx burners.

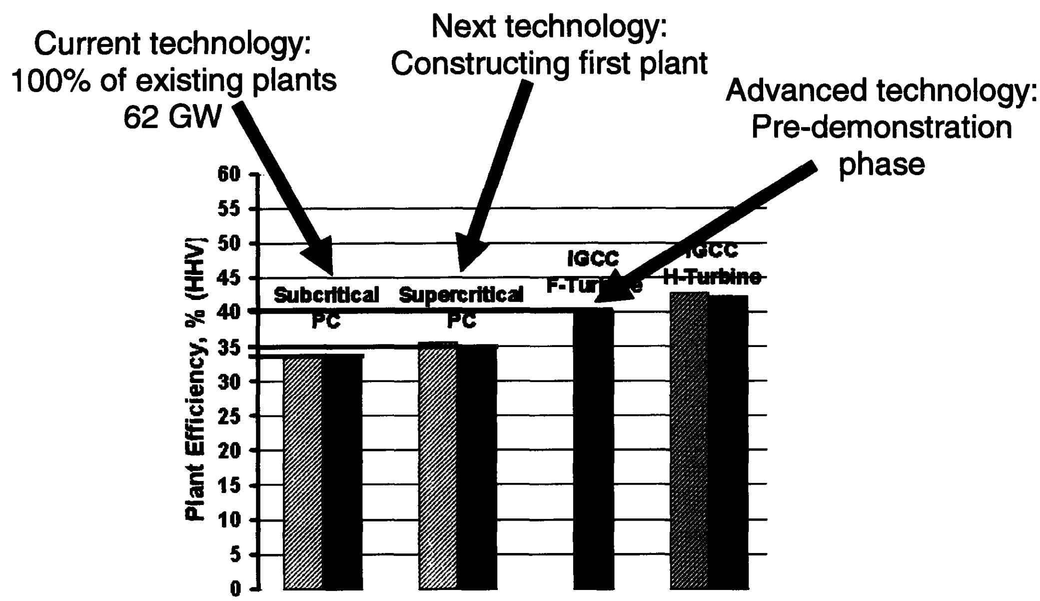
Despite the lack of government requirements, many plants have stricter pollution controls for other reasons. Many plants receive funding from international agencies such as the World Bank and the Asian Development Bank, which require funded plants to install specific pollution-control technologies. Additionally, plants may opt for greater control for other reasons. Reliance Industries decided to include greater pollution control on their greenfield Jamnagar refinery's captive power plant. As the refinery products were intended for export, Reliance wanted its plant to meet international standards.

Advanced Technologies

Until 2005, technology advancement in coal-based power plants has consisted of scaling in size up to 500 MW. Reheat was added to the steam cycle for plants larger than 70 MW. Material science technology has improved turbine blade performance. Future plants can be advanced through the use of a super-critical or ultra super-critical steam cycle. Current subcritical PC plants in India have an efficiency range of 20-32%. Advanced technologies can increase efficiency to above 35%. Figure 21 shows the average efficiency for subcritical combustion plants in India and the expected efficiencies of supercritical combustion and IGCC plants in India. The notes refer to the current status of these plants in India.

[71] The actual regulations can be found in the appendix.

Figure 21: Coal-based power plant technologies in India[72]



NTPC expressed interest in moving to higher efficiency coal plants and thus decided to build a supercritical pulverized coal (SC PC) plant, a technology that is currently used in the US and has been commercially used in Europe. NTPC decided to build a plant and tendered bids from national and foreign manufacturers. BHEL was disqualified from the bidding process for not having demonstrated SC PC (although it had done research into the technology). A contract was awarded in 2005 to a Korean company, Doosan, for engineering, procuring, and constructing the first supercritical plant. The 3x660 MW unit plant is to be installed in Sipat, Chhattisgarh. The turn-key plant is supposed to be turned over to NTPC in 2009.

Figure 22: Supercritical PC Adoption in India

	Super critical PC
Acquisition	Procure from Doosan
Development	Licensing agreement with Alstom

Figure 22 shows that the technology was acquired from Doosan, but there are efforts within India to develop the technology indigenously. BHEL has decided to leapfrog its own technology development and acquire a license from Alstom for supercritical technology up to 800 MW and circulating fluidized bed technology up to 250 MW. The adoption of this technology in India is explored in more detail in the following case study.

[72] Chen, Tan-Ping. "Effects Of Coal Ash Content On Cost Of Generation For IGCC Power Plant." The grey bars refer to plants using washed coal that has lower ash content. The solid bars show the efficiency for plants using coal that has not been washed. The vast majority of coal consumed in India is not washed.

Supercritical case study

The adoption of supercritical PC technology has happened very recently and can be used to gain an understanding of how new technology is introduced in India. The process has occurred in two stages. The first is the procurement of technology from a foreign manufacturer and the second is the licensing of the technology by BHEL.

Supercritical PC combustion achieves higher efficiency than subcritical PC combustion by modifying the steam cycle; the boiler remains unchanged. The steam pressure and temperature are increased to the point where the two-phase mixture of liquid water and gaseous steam is replaced by a one-phase super-critical fluid, whose properties change as the temperature changes. This cycle requires advanced materials technology to manufacture piping that can withstand the higher pressure.

India is currently constructing its first supercritical PC plant. China has completed many supercritical PC plants. Why is India only now moving to advanced technologies despite building multiple coal-based power plants each year? This is partly due to economics and procurement policy, which have had small changes in the last few years.

In the last few years, the largest emphasis in the power sector by the Indian central government has been on increasing capacity. This has been accomplished by building new plants in the quickest way possible and improving plant load factor and operating efficiency of existing plants. The former was the preferred method as efficiency improvements did not make sense in the previous accounting methods for power purchase agreements.

Previously, power was sold on a cost-plus basis. This meant that the SEBs were responsible for paying the generation companies (gencos) the cost of their generation plus a specified return. This meant that the generation company would get the return no matter the operating conditions of the plant. Therefore renovation and modernization to improve the operations of the plant would not increase the profits made by the plant—giving no incentive to spend the cash upfront to undertake these efforts. The results were less efficient plants, more pollution, more coal used, and higher prices charged by the gencos to the SEBs.

The SEBs often did not honor these contracts due to their lack of funds. This also served to limit new plant build as the private gencos did not trust the PPAs issued by the SEBs. Thus, most of the growth was done by the state and central sector governments. The tenders for construction were based on lowest costs among pre-approved vendors. One stipulation was that the vendor must have experience manufacturing the specific technology that was being procured. This meant that BHEL, the national boiler and turbine manufacturer, could only sell boiler/turbine sets in pre-determined sizes: 500 MW, 250 MW, 200 MW, and lower. Knowing this, many of the generation companies decided to build plants at these sizes. The appeal that BHEL had to these companies was manifold: ties that the centrally government-owned NTPC has to the central government-owned BHEL, the relatively lower costs of BHEL compared to foreign manufacturers, and the in-country services BHEL was able to offer to power plants during operation.

The result is that 75% of coal plants were built with the available BHEL technology. (Some specialty chemicals-producing plants, such as fluidized bed combustion technology, were procured from foreign companies, but this was not common.) Working with an indigenous supplier was supposed to allow quicker turn-around on new plants.

Recent legislation has served to further enable quicker capacity additions. The permitting process for new plants was fast-tracked. A higher rate of return was offered to plants with plant load factors above a certain share. The accounting methods were changed from a cost-plus basis to a price basis. This meant that the plants would receive a price per kilowatt independent of their operations. This in turn meant that plants could improve financial performance by reducing costs and improving efficiency.

This was a paradigm shift in the power sector: plant efficiency became important and this encouraged new power projects to be considered on the basis of lifetime levelized cost as well as capital costs. Thus the type of plant to be built received new consideration. The national leader in power plant construction, NTPC, culminated this shift with the tendering of India's first super-critical PC plant.

As hypothesized earlier, the reasons for this shift relate to the changes in the regulatory structure and economics. NTPC decided to switch to a higher efficiency plant after having performed renovation and modernization (R&M) on its existing plants. These efforts were limited by many factors, including the sub-critical steam cycle. A supercritical steam cycle offered the possibility of increasing maximum possible efficiency while using less coal and emitting less pollution.

NTPC decided to build the super-critical PC plant after it had succeeded in improving the performance of its existing plants. NTPC was able to see the benefits conferred from the R&M efforts and realize that additional gains could only be made through technological changes. At this point, NTPC announced that it would build the country's first super-critical PC plant.

The plant would be sited at Sipat. To begin the process, NTPC first commissioned a technoeconomic study from Japan's Electric Power Development Company (EPDC). The study estimates that the capital costs of a 500 MW super-critical PC plant would be 2% higher than that of a subcritical PC plant with an increase of efficiency from 38.64% to 39.6%. The increase in temperature and pressure for the steam cycle requires advanced materials that are more difficult to work with.[73]

When NTPC procured bids for the Sipat plant, South Korean-based Doosan, BHEL, and a few other firms responded. The boiler order was awarded to Doosan and the turbine order went to TechnoPromExporte (TPE) of Russia. BHEL was disqualified from consideration.

BHEL did not have experience manufacturing supercritical PC boilers. It had previously teamed up with Babcock Borsig on a supercritical technology agreement before Babcock Borsig went out of business (insolvency occurred in July 2002). BHEL had begun research efforts in 2001 to develop and commercialize this technology.[74] In 2002, BHEL updated its manufacturing center in Haridwar to be able to manufacture 660 MW supercritical steam turbines. During this initial partnership, BHEL did not construct any commercially operating supercritical PC plants. Without experience or a foreign partner with experience, it would be difficult for BHEL to receive a contract. This lack of trust in BHEL's untested technologies was reiterated by one state's generation corporation which remarked that it would not procure supercritical PC technology from BHEL, preferring a foreign vendor with proven technology.

[73] "Technology status of thermal power plants in India and opportunities in renovation and Modernization." TERI. New Delhi, India. Online: http://www.teri.res.in/teriin/opet/reports/tpp.pdf. Estimates are based on ambient operating conditions in India as well as the type of coal used. EPDC concluded that the most applicable steam conditions for India is 246 kg/cm2, 538° C/566° C. "Since the beginning of the 90's, steam pressure was notably increased. Maximum allowable working pressure was raised to 285 bar and temperature was raised in steps from 565° C to 580° C and 600° C respectively for the reheater. The steam parameters in the new projects are even higher and exceed 600° C and 620° C respectively. The improvement in efficiency varies from 1.3% to 3.6%. "

[74] Ramachandran, KG, Chairman & Managing Director BHEL. "Cmd's Address At The 37th Agm." New Delhi. 28 September 2001. Online: http://www.bhel.com/bhel/press_release/speach_2.htm.

BHEL was forced to find another foreign partner. It formed an agreement with Alstom in October 2005. Alstom would transfer technology to BHEL and BHEL would be required to source some components from Alstom for supercritical power projects. A senior official from Alstom commented that this was the best way for the company to gain a presence in India, despite worries that BHEL could later come back and compete with them for projects in other countries.

With its new partner, BHEL placed a bid for a second NTPC super-critical PC plant at Barh. Its bid was once again turned down, possibly because of its higher estimates due to the high cost components from the European-based Alstom. The Barh order went exclusively to Russia's TPE.[75]

The following shows a timeline of the super-critical PC plant orders and construction:

Figure 23: Timeline of adoption of supercritical PC technology[76]

1965	30 MW size coal plants installed (imported equipment)
1970	
1975	
	100 MW size coal plants developed by BHEL
1980	200-250 MW size coal plants developed by BHEL
1985	
	500 MW size coal plants developed by BHEL
1990	
1995	
	Standing Independent Group (SIG) formed by GoI to oversee mega power projects (would not require technoeconomic clearance from CEA)
	MOU for PPA signed for 6x660MW Hirma TPS. Expected financial closure date of 2002. Construction finished by 2006.
2000	Super-critical project at Sipat announced by MoP

[75] Purkayastha, Prabir. "BHEL Disinvestments - An Attack On The Power Sector." People's Democracy. 3 July 2005. Online: http://pd.cpim.org/2005/0703/07032005_snd.htm.

[76] Shukla, PR, Debashish Biswas, Tirthankar Nag, Amee Yajnik, Thomas Heller and David G. Victor. "Impact of Power Sector Reforms on Technology, Efficiency and Emissions: Case Study of Andhra Pradesh, India." Program on Energy and Sustainable Development, Stanford University. March 2004. Online: http://iis-db.stanford.edu/pubs/20452/wp20_apcase_5mar04.pdf.
Sbi Capital Markets Limited. "Consultants' Report in the matter of 6x660 Mw Hirma Power Project." Submitted to the Central Electricity Regulatory Commission. 31 March 2000. Online: http://cercind.org/cons.pdf

Figure 23 (cont): Timeline of adoption of supercritical PC technology

	Sipat I 3x660MW supercritical plant approved (Rs. 8323.4 crore)
	Sipat II changed from 1x660MW supercritical to 2x500MW subcritical PC
	Barh 3x660MW supercritical plant approved (Rs. 8693.0 crore)
	Order placed for Sipat I
2005	BHEL enters agreement with Allstom for design and manufacture of large-size supercritical boilers
	Construction begun on Sipat\
	Financing proposal for North Karanpura TPS 3x660MW (considering for pilot plant for CDM) Financing by JBIC. Not yet approved.
	Construction to begin on Barh
	Expected finish of first 660 MW of super-critical PC at Sipat I
	Expected finish of second and third 660 MW of super-critical PC at Sipat I
2010	Expected finish of all three units of 660 MW of super-critical PC at Barh

Thus two super-critical PC plants have been procured by NPTC, both of which are in very preliminary stages. The central government had initially set a goal of having 15% of new thermal power plants use supercritical technology. This amounts to five supercritical plants to be built between 2002 and 2007. The Ministry of Power stated that this was not achieved due to "technological constraint". The government said that there were unspecified "tendering difficulties" for Sipat that would constrain future purchases.

The tendering difficulties may have resulted from various factors. It may have been more expensive and more paperwork to order the plant from a foreign manufacturer. Internal politics may have also been a factor—spending more money on foreign technology when the money could have gone to the central government manufacturer, especially now that it has acquired a license to manufacture the technology. However, NTPC and other utilities are still reluctant to use BHEL technology as it has not been commercially proven.[77]

On the other hand, Prashant Periwal—Asst. Vice President and utilities analyst for B&K Securities in Mumbai, India, has confidence in BHEL's abilities. He expects that they will have the ability to successfully manufacture, construct, and operate the super-critical technology. He is more pessimistic on the ability to implement super-critical technology. While NTPC can effectively operate advanced technologies, the state electricity boards and generating companies should concentrate on successfully operating their current fleet of subcritical PC coal plants.

India's experience with supercritical PC technology shows that there are actors within the government and industry that are pushing for advanced technologies. However, the same processes and organizational structures that have allowed for greater expenditures on advanced technologies are the same structures that are causing political difficulties. The integration of the central sector undertakings has tied the organizations together, putting pressure on the utility to procure equipment from the central sector manufacturer.

[77] Sasi, Anil. "Tech constraint trips plan for cheaper power". The Hindu Business Line. New Delhi. 24 April 2005. Online: http://www.thehindubusinessline.com/2005/04/25/stories/2005042501950100.htm.

Beyond super critical PC

Beyond supercritical PC there are opportunities to move to ultra-supercritical pulverized coal combustion (USC PC) and integrated gasification combined cycle (IGCC) technology. Neither has been demonstrated in India. There are commercially operating USC PC plants in Europe. The difficulty in this technology is dealing with and maintaining the advanced materials required to handle the high pressure and temperature steam cycle. This is true to a lesser degree with supercritical PC. Experience with SC PC will aid with handling USC PC technology.

BHEL has led the country's research efforts into IGCC. It currently has a 6MW pressurized fluidized bed gasifier that had been repowered from a moving bed gasifier. The Indian Institute of Chemical Technology is supporting this project through research on gasifier peripheral components.

Figure 24: IGCC adoption in India

IGCC	
Acquisition	USAID sponsored study
Development	BHEL

NTPC, with financing from the Ministry of Power, has expressed an interest in building a 100MW IGCC demonstration plant. It will have to choose between BHEL's technology and USAID's recommended technology. USAID has commissioned Nexant to develop an initial design and cost estimate for a 100 MW IGCC demonstration plant in India. USAID initially considering the U-Gas gasifier, the Noell gasifier, the Lurgi gasifier, and the Texaco gasifier. The U-gas gasifier was finally chosen as it is a fluidized bed gasifier, similar to BHEL's, and is best suited for Indian coal's high ash content.

The U-gas gasifier has not yet been demonstrated at the 100 MW level. There are four plants larger than this in operation world-wide. Two plants in the US, one in the Netherlands, and one in Spain all operate at a demonstration size (250 MW – 300 MW). It took additional capital upfront to construct these plants. The US Department of Energy has reported that one such plant, the Polk Power Station, is "generating low cost electricity".[78]

Significance for IGCC

Lessons can be learned from the supercritical development experience to gain insight into if and when India would adopt coal gasification technology. To apply this to gasification, it is important to note an important difference between gasification and supercritical PC. Supercritical PC nears levelized-cost competitiveness with subcritical PC technology, although the capital costs are significantly higher. Supercritical PC is a proven technology that is commercially available. It was introduced at a time when many changes and initiatives were happening in India. The country was in the midst of deregulating the electricity sector and price and efficiency were receiving greater emphasis. NTPC was growing as an

[78] National Energy Technology Laboratory (NETL), Department of Energy, US government. "Clean Coal Technology: Tampa Electric Integrated Gasification Combined-Cycle Project." August 2004. Online: www.netl.doe.gov.

institution and wanted to move into new areas, and was prepared to undertake a large new R&D effort. Additionally, gas prices had dramatically increased and the recently installed gas capacity was looking less competitive.

Increasing coal conversion efficiency became increasingly important as shortages became manifest through bottlenecks in the transportation infrastructure and lack of reforms in the coal mining sector. Emphasis was placed on large mine mouth plants, which mitigated the need to transport the coal over long distances. Advanced technologies seemed to fit well into this scheme based on the economies of scale that could be earned from the mega power plants at mine mouth.

These conditions are very specific for super-critical technology and do not necessarily match apply to IGCC development. India is in a growth period requiring more rapid additions than it can currently meet. This requires rapid input of infrastructure. Supercritical PC can meet these requirements through foreign collaboration. IGCC does not meet this definition as it is currently not commercially proven for power generation.

IGCC could help mitigate the coal shortage at the forecasted efficiency, but this efficiency has not yet been proven. Furthermore, it is much more expensive to build IGCC plants. The main benefits received from IGCC—CO_2 capture, environmental control, and cogeneration—are not part of India's immediate goals. Environmental control has been handled on a case-by-case basis. CO_2 is not an immediate concern. Cogeneration is subordinated by the great need for power.

However, with policy changes in the sector, there may be unique opportunities for IGCC. These may be parallel in one sense to those for super-critical PC. NTPC has expressed an interest and TERI has advocated for mega power plants of over 1,500 MW to be installed at coal mining sites. These larger plants have a larger environmental impact. This impact may ultimately limit the size of plants to be built. TERI estimates that the plant size should be limited due to pollution impacts. One way to surpass this size may be the introduction of IGCC, which allows for easier and cheaper pollution control. Limestone in a fluidized bed gasifier can react with and capture the SO_x. The mercury and NO_x can be removed from the syngas before combustion. The CO_2 can be captured with economies of scale at these larger plants and sequestered.

There are many benefits that may drive the technology and many drawbacks that may impede development. The next chapter will further explore the benefits and drawbacks, specifically focusing on the projected costs as well as efficiency benefits.

5. IGCC

To understand whether there is value to India in adopting IGCC technology, it is necessary to understand the benefits and drawbacks and weigh those against the concerns and needs in India. The concerns and needs were addressed in the previous chapters in looking at the energy deficits and the energy policy. Now the costs and benefits of IGCC will be considered.

The higher capital costs and marginally increased efficiency may not make it obvious that IGCC is worth the effort, but it is important to understand the value of optionality. India's continued research and development of IGCC presents a technology option with value. However, this value needs to be weighed against the costs and options given up, if any.

Benefits and drawbacks

The gasification of coal provides benefits that aren't available from pulverized coal operations. The benefits arrive from the gasifier's ability to generate many products: electricity, chemicals, fuel storage, hydrogen, liquid fuels, and synthetic methane.

- Power: IGCC generates power directly with a gas turbine and indirectly with a steam cycle, providing the potential for higher efficiencies than PC plants.
- CO_2 capture capability: CO_2 can be captured from an IGCC plant with a smaller reduction in net efficiency as compared to a PC plant. However, this advantage of IGCC could be mitigated through technological advances in PC capture technology.
- Chemicals: IGCC technologies are already proven for chemical production, specifically ammonia production in India.
- Co-firing: Can gasify a combination of coal, natural gas, biomass and waste.

Gasification provides benefits through the options it provides. The main drawbacks are the increased cost and the possibility of giving up another technology choice for this one. For those reasons, gasification development should be seen as an option to be considered along with the other technologies and not the only solution.

Gasifiers are available on the world market that would provide the same benefits as listed above. However, there are specific benefits that would be derived from India's developing its own gasifier, which would not be available from foreign-owned gasifiers:

- Potentially lower cost gasifiers and the potential to make profits by selling the technology internationally. There is currently not a strong world demand for this technology and it is not certain that there will be in the future. This will depend, among other things, on the strength of a future global climate change regime and the availability of alternative energy sources and technologies.
- The externalities of the research could create spin-off technologies useful in India.
- The gasifier would be optimized for Indian conditions in terms of working with higher-ash Indian coal and higher-temperature ambient conditions

There are also risks associated with pursuing development of this technology. With increasing risk comes a stronger pull to acquire the technology from a proven vendor.

- The technology may never work effectively. This happened with a FBG unit that was constructed in Pinon Pines in the US and never reached steady state operation.
- The project turns into a large capital sink. A very large amount of funds are spent on this project at the expense of other projects to further develop the country.
- By choosing to develop one type of gasifier, experience is lost with other types of gasifiers. Knowledge of operations and technical issues relevant to the other types of technologies is not developed.

In the next section the economics will be evaluated to understand the level of government commitment required to make this technology competitive with other technologies. While most pricing studies have been done in the United States, there is some data available for India.

Economics

The more established coal-based power generation technologies are generally less expensive than the advanced technologies.[79] This is generally believed true for every country. India has limited experience with advanced technologies, and thus these prices can only be estimated.

Few IGCC plants have been built at large sizes for power production. The capital costs for IGCC are higher than the fully commercialized PC plants as shown in table 14. The Nexant projections in table 14 are for an IGCC plant that uses the U-Gas gasifier developed at the Gas Technology Institute (GTI) in the United States. The cost of IGCC shown here is similar in the US and in India. This is due to the fact that the costs of the power plant depend significantly on advanced technology that would be bought from GTI in the United States.

[79] This analysis considers the order of most established to least established technologies to be: subcritical PC, supercritical PC, and IGCC.

Table 14: Capital Costs (2005 $ / kW) [80]

2005 $ / MW	Subcritical PC	Supercritical PC	Ultra-Supercritical PC	IGCC	Cost assumptions
Nexant —for an Indian power plant.	1,000	1,260		1,618 (H turbine) 1,830 (F turbine)	25-year plant life and 7,000-hours/y plant operation. A typical load center power plant site in India (such as NTPC's Dadri power station near Delhi), approximately 1,000 MW plant size, 70% sulfur removal in the power generation, and 50 ppmv NOx. Converted from given 2002 $ to 2005 $ using 1.09 2002$ = 1 2005$ (US Bureau of Labor Stastics) and 2002 1$ = 48.50Rs. Supercritical contains FGD.
MIT coal study. US plant	1,280	1,330	1,360	1,430	Costs are quoted for a 500 MW plant built in the US, and are given in 2005 $/kW net generation capacity. The IGCC contains a spare gasifier. Capacity factor of 85 %, carrying charge factor of 15 %, and a fuel price of $1.42/GJ ($1.50/million BTU) HHV. The IGCC costs are for an oxy-blown plant.
MIT. Capture -ready	2,230	2,140	2,090	1,890	
Sathaye (Proposals for plants in India)	1,450 (1,328)	Bhadravati (private) 993 MW. 2460 kcal/kWh.			In black is 2005 dollars, in red is given 2002/03 dollars. 14% discount rate. 80% plant load factor. Rupees converted into US dollars using a 2002–2003 exchange rate of Rs. 47/US $. Rupee debt is raised at 12-14% nominal interest rate, while that for the US is 6-8% nominal. Debt to equity ranges from 2 to 5. (However NTPC does have access to lower cost financing.) Does not include FGD units. Converted from given 2002 $ to 2005 $ using 1.09 2002$ = 1 2005$ (US Bureau of Labor Stastics). Original data reported by Sathaye given in parenthesis). 30 year life of plant. Fuel cost varies per plant based on location. 80% plant load factor. The proposals specify a heat rate for the plant based on plant conditions and the coal. Heat rate varies from 0.69 to 0.77 kg coal / kWh (2350 to 2460 kcal/kWh).
	1,050 (967)	Hirma (private) 4320 MW. 2460 kcal/kWh.			
	1,260 (1,158)	Rayalaseema (public) 420 MW. 2350 kcal/kWh.			
	1,040 (954)	Ramagundum (private) 510 MW. 2400 kcal/kWh.			
NTPC Estimate		1,070			1980 MW Sipat super-critical plant. The cost includes financing charges and interest during construction.

[80] Sathaye, J and A Phadke. "Cost of electric power sector carbon mitigation in India: international implications". Energy Policy: 34 (13, 2006).
Press Information Bureau, Government of India. "Latest PIB Releases." Rajya Sabha. July 2000. Online: http://pib.nic.in/archieve/lreleng/lyr2000/rjul2000/r27072000.html.
The estimated cost of the project is Rs. 7798.7 crore at 1st quarter. 1999 prices for 1980 MW super-critical Sipat plant. Rs. 7798.7 crore/1980 MW. In June 2001, 1$ = 43 Rs. What cost $1 in 1999 has the same buying power as $1.17 in 2005
Bureau of Labor Statistics, US Department of Labor, Government of USA. Data for inflation and exchange rates. Accessed: October 2005. Online: http://www.bls.gov/cpi/.
Project Monitor. "Sipat Super Thermal Power- II gets CEA's nod." 3 September 2002. Mumbai, India. Online: http://projectsmonitor.com/detailnews.asp?newsid=5788.

7798.70	Rs crore / 1980 MW			2530	
77987000000.00	Rs/1980MW			25300000000.00	
39387373.74	Rs/MW			12777777.78	
39387.37	Rs/kW			38333.33	
915.99	1999$ / kW	43 1999Rs = 1 1999$		782.31	49 2002Rs = 1 2002$
1071.70	2005$ / kW	1.17 2005$ = 1 1999$	852.72		1.09 2005$ = 1 2002$

Table 14 shows that the capital costs are 60% more expensive for an IGCC plant over a new subcritical PC plant in India. The IGCC plants are shown in this analysis to be more expensive in India than the US. This may be for many reasons.

A high discount rate is applied in India due to the risk factor. This means that capital costs have a bigger impact. Decisions are made with a stronger emphasis on the near term and projects are chosen with short payback periods. Rupee debt is raised at 12-14% nominal interest rate, while that for the US is 6-8% nominal. While the cost of debt is higher in India, the plants are generally highly leveraged with a debt to equity ratio ranging from 2 to 5. Having high debt would reduce the overall costs as debt is cheaper than equity. Another offset is that NTPC, as a central sector entity, has access to lower cost financing. Costs would be increased in India as construction times are generally longer due to unclear and evolving regulatory processes.

NTPC's estimated cost for the Sipat supercritical plant is significantly lower than the other estimates. A likely explanation is that this is the estimated cost before construction begins on the plant. This is the first plant in India with this technology. This number may prove to be too optimistic after the project is actually completed.

The studies shown in table 14 suggest that the capital costs for IGCC plants will be more expensive in India than the US. This is partially due to the fact that the technologies considered in the Nexant study for the IGCC plant are fluidized bed gasifiers that have not been demonstrated, that only exist at benchscale test sites. On the other hand, the technologies considered in the MIT study for the US have been demonstrated at a 250 MW scale.

Capture-ready IGCC, that is, IGCC plants built with the equipment necessary to capture CO_2, is less expensive than the capture-ready supercritical PC plant. This is because capture-ready IGCC requires less equipment and is a simpler process. The concentration of CO_2 in the syngas from a gasifier is high and the gas stream is at a high pressure. The supercritical PC flue gas is at atmospheric pressure and the CO_2 needs to be separated from multiple gases (which are byproducts of combustion) that are at higher concentrations than those found in the syngas from a gasifier.

Table 15 lists the levelized costs for various power generation technologies from the same studies as shown in table 14.

Table 15: Levelized costs (2005 $ / kWh)[81]

	Subcritical PC	Supercritical PC	Ultra-Supercritical PC	IGCC	Cost assumptions
Nexant—for an Indian power plant.	0.04846	0.05574		0.0607 (H turbine) 0.0674 (F turbine)	25-year plant life and 7,000-hours/y plant operation. A typical load center power plant site in India (such as NTPC's Dadri power station near Delhi), approximately 1,000 MW plant size, 70% sulfur removal in the power generation, and 50 ppmv NOx. Converted from given 2002 $ to 2005 $ using 1.09 2002$ = 1 2005$ (US Bureau of Labor Stastics) and 2002 1$ = 48.50Rs. Supercritical contains FGD.
MIT coal study. US plant	0.048	0.0475	0.0467	0.0513	Costs are quoted for a 500 MW plant built in the US, and are given in 2005 $/kW net generation capacity. The IGCC contains a spare gasifier. Capacity factor of 85 %, carrying charge factor of 15 %, and a fuel price of $1.42/GJ ($1.50/million BTU) HHV. The IGCC costs are for an oxy-blown plant.
MIT coal study. Capture-ready	0.0817	0.0769	0.0734	0.0652	
Sathaye (Proposals for plants in India)	0.048 (0.044)	Bhadravati (private) 993 MW. 2460 kcal/kWh.			In black is 2005 dollars, in red is given 2002/03 dollars. 14% discount rate. 80% plant load factor. Rupees converted into US dollars using a 2002–2003 exchange rate of Rs. 47/US $. Rupee debt is raised at 12-14% nominal interest rate, while that for the US is 6-8% nominal. Debt to equity ranges from 2 to 5. (However NTPC does have access to lower cost financing.) Does not include FGD units. Converted from given 2002 $ to 2005 $ using 1.09 2002$ = 1 2005$ (US Bureau of Labor Stastics). Original data reported by Sathaye given in parenthesis). 30 year life of plant. Fuel cost varies per plant based on location. 80% plant load factor. The proposals specify a heat rate for the plant based on plant conditions and the coal. Heat rate varies from 0.69 to 0.77 kg coal / kWh (2350 to 2460 kcal/kWh).
	0.029 (0.027)	Hirma (private) 4320 MW. 2460 kcal/kWh.			
	0.050 (0.046)	Rayalaseema (public) 420 MW. 2350 kcal/kWh.			
	0.029 (0.027)	Ramagundum (private) 510 MW. 2400 kcal/kWh.			

Table 15 shows that the capital costs are 33% more expensive for an IGCC plant over new subcritical PC plant in India. The more advanced technologies are more expensive due to more expensive capital costs and more complex operation. This does not hold true for supercritical PC technology in the US as the technology is not dramatically different from subcritical PC technology and there is a reduced fuel cost due to reduction in coal input. This would seem to be true for India as well, but is not reflected in these numbers. There are several possible reasons for the higher levelized cost for supercritical PC. One is that BHEL and other manufacturers in developing countries are able to install and build only subcritical plants, but these same manufacturers generally cannot produce supercritical PC technology. It is necessary to purchase the technology from foreign manufacturers, whose prices are generally higher than those for BHEL. Since 1991, import of this equipment levied a 20% custom duty, but more recent legislation has exempted major power plant components from customs duties.[82]

Another surprise is that the levelized costs of generation in India are equal to or more expensive than those in the US. This may again be partially due to the fact that the advanced technologies need to be

[81] For citation see table 14.
[82] Power Engineering International. "Connecting A New Generation Of Power." Power-Gen Conference. 1-3 February 2005. Online: http://pgia05.events.pennnet.com/.

sourced from developed countries or to be originally derived from licenses from companies in developed countries. For example, BHEL's turbine technology is based on a GE and Siemens licensing agreement. Plants may also be more expensive as the cost of capital is higher in India compared to the US, as mentioned previously.

Additionally, the operation of plants in India requires more coal for the same amount of generation as compared to the US. This is due to the lower quality Indian coal that has a lower heat rate and higher ash content.

Due to the higher costs of supercritical technology, the installation of supercritical plants requires some other motivation beyond economics. This motivation is not necessary if the technology is assimilated and manufactured for a reduced price by BHEL.

Government policy may serve to offset the additional costs. One central government policy currently in place serves to facilitate mega power projects (plants that are larger than 1000 MW or that supplies power to more than one state). The official policy states that:[83]

> The import of capital equipment would be free of customs duty for these projects. In order to ensure that domestic bidders are not adversely affected, price preference of 15% would be given for the projects under public sector, while deemed export benefits as per the EXIM policy would be given to domestic bidders for projects both under public and private sector. The domestic bidders would be allowed to quote in US Dollars or any other foreign currency of their choice. In addition, the income-tax holiday regime would be continued with the provision that the tax holiday period of 10 years can be claimed by a promoter in any block of 10 years, within the first 15 years. The State Governments are requested to exempt supplies made to mega power plants from sales tax and local levies.

In addition, the import duty for equipment for all power plants was reduced. Originally, items such as spare parts would be levied customs duties as high as 50.8%. This was capped at 25% by the Ministry of Power.[84]

The provisions would make imported technologies more competitive with domestic technologies. The cheapest type of power generation in India is from large hydroelectric dams. PR Shukla of Indian Institute of Management Ahmedabad undertook a study whereby he compared the levelized costs of various types of plants. Shukla normalized the costs of the plants using assumptions typical for the Indian market (see footnote). He then ranked the plants from lowest levelized cost to highest levelized. The results show that large hydro has the lowest levelized cost of electricity generation and solar PV has the highest levelized cost of electricity generation.

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[83] Ministry of Power, Government of India. "Policy for Setting up of Mega Power Projects in Pvt Sector." New Delhi, India. 1995-1999. Online: http://powermin.nic.in/acts_notification/policy_mega_power_projects.htm.

[84] Standing Committee On Energy, Thirteenth Lok Sabha. Ministry of Power, Government of India. New Delhi. 2003. Online: http://164.100.24.208/ls/committeeR/Energy/40.pdf.

Table 16: Ranking of levelized cost of generation of various types of power generation units (From least expensive to most expensive) [85]

1. Large Hydro
2. Small hydro
3. Pithead subcritical plant fired on domestic coal, 500 MW
4. Pithead supercritical plant fired on domestic coal
5. Advanced class gas turbines in combined cycle mode
6. Pithead subcritical plant fired on domestic coal, 250 MW
7. Normal class gas turbines in combined cycle mode
8. Nuclear
9. Biomass
10. Non-pithead subcritical plant fired on domestic coal, 500 MW
11. Non-pithead supercritical plant fired on domestic coal
12. Coal plant fired on imported coal, 500 MW
13. Gas OC advanced
14. Gas OC normal
15. Atmospheric fluidized bed combustion (AFBC)
16. Lignite-fired 125 MW AFBC
17. Lignite-fired 125 MW normal combustion
18. Coal plant fired on imported coal, 250 MW
19. Pressurized fluidized bed combustion (PFBC)
20. Liquefied natural gas plant
21. Naphtha-fired plant
22. Solar photovoltaic

This ranking shows that if levelized costs are the biggest concern, then hydro plants will be the first to be built. However, hydro plants can only be placed where conditions allow for damming. Therefore the next greatest demand will be for pithead coal plants. This resonates with current plans whereby NTPC plans to build new plants at the pithead. In states without coal reserves, combined cycle natural gas plants are more attractive.

The differential for levelized costs between supercritical and subcritical PC is reduced for larger plants due to the economies of scale in the capital costs. Additionally, this study was performed before the import duties were lowered, suggesting that the imported supercritical technology may be more economical than shown here.

CO_2 emissions

IGCC will offer benefits in the form of savings in CO_2 emissions. This is achievable in two ways: increasing efficiency and lower cost opportunities for CO_2 capture and storage. While cutting CO_2 emissions may not be India's priority now, there may be strong incentives in the future to do so. India may become part of a global climate change regime that will require it to reduce emissions. Additionally,

[85] Shukla, PR. Electricity Reforms in India.
The actual ordering could change slightly based on changes in heat rates and other factors. The factors assumed for this analysis are as follows:
Debt:equity ratio of 70:30. Lending rates of 7.25 to 9%. ROE of 14%. Real discount rate of 6% based on WACC. 10.5% interest rate for calculating interest on working capital with working capital requirements as per CERC norms.

it may be part of a CO_2 trading system where other countries will invest in more efficient processes to reduce CO_2 emissions in India. For these reasons, it is important to understand how advanced technologies could reduce emissions.

The CO_2 capture has the potential to reduce CO_2 emissions to near zero. However, without capture, there are still benefits for pollution reduction for CO_2, SO_x, NO_x, and mercury. The analysis described below was done to quantify this reduction in emissions.

CO_2 Savings from Advanced Technology

An analysis was undertaken to determine the reduction in emissions achieved by moving to more advanced technologies. More advanced technologies are more efficient, meaning that the same number of kilowatt hours of electricity can be generated with less coal.

The analysis began by taking the IEA estimates for electricity generation from coal plants from 2002 to 2030. This is shown in figure 25. The numbers were adjusted to account for power used at the power station. The area of the yellow rectangle represents the total generation over 25 years from the coal plants existing as of 2005. The triangular area represents the total generation from the new coal plants.

Figure 25: Projected electricity generation from coal in India (TWh)

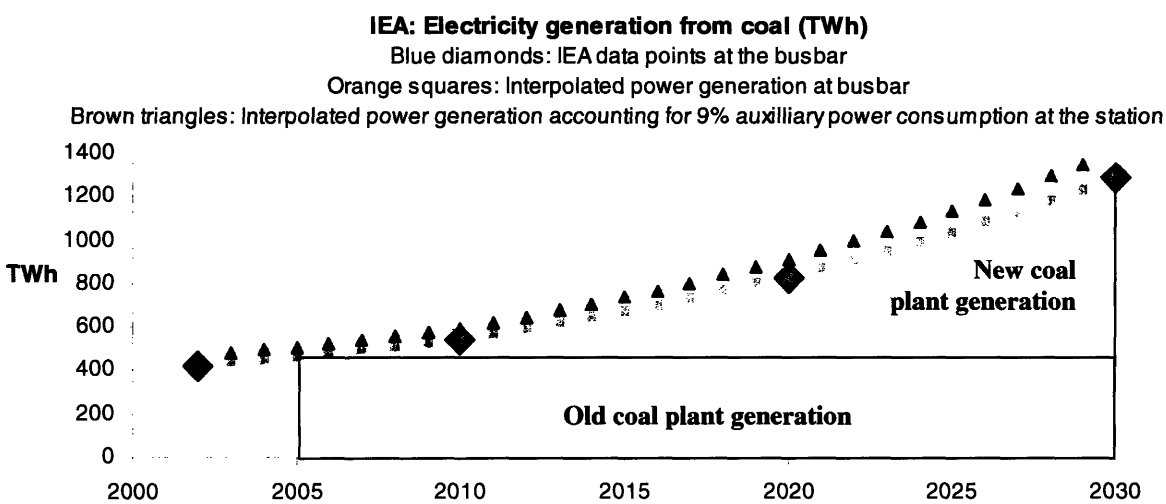


Table 17 below shows the assumptions necessary to calculate the CO_2 emissions. The efficiencies are based on the MIT coal study and would be roughly 4% lower if considering the higher heating value of coal.[86] The amount of CO_2 emissions is determined using the carbon content of coal of 41.2% as given by TERI.

[86] "The higher heating value (HHV) of the fuel is the maximum potential energy in dry fuel. LHV is the potential energy in a fuel if the water vapor from the combustion of the fuel is not condensed. Since the LHV assumes that fuel delivers less energy input than the HHV, a thermodynamic efficiency, η, based on the LHV will be higher than one based on HHV in simple inverse proportion; that is, (η LHV)/ (η HHV) = HHV/LHV. The numerical difference between LHV and HHV depends on the fuel, and is smallest for coal (LHV roughly 4 percent lower than HHV)." Source: Committee on R&D Opportunities for Advanced Fossil-Fueled Energy Complexes, Board on Energy and Environmental Systems, Commission on

Table 17: Assumptions for emissions analysis[87]

Type of Plant	**Efficiency**	**Heat rate** kg/kWh	**Levelized cost of generation** (US $ / hWh)
Old subcritical PC	30%	0.72	0.056
New subcritical PC	34%	0.626	0.048
Supercritical PC	38%	0.56	0.056
IGCC (or Ultra-supercritical PC)	42%	0.51	0.064

The analysis was performed by assuming 5 different scenarios over the 25 year study beginning in 2005 and ending in 2030.

Scenarios

1. All new plants are subcritical PC
2. Half of new plants are subcritical PC and half are *supercritical* PC
3. All new plants are *supercritical* PC
4. 2005—2015: ½ subcritical PC and ½ *supercritical* PC
   2015—2025: ½ *supercritical* PC and ½ IGCC
   2025—2030: all IGCC
5. All new plants are IGCC

The amount of coal needed for the preceding scenarios was calculated by using the heat rate and plant efficiencies to convert the projected electricity demand into mass of coal required. The heat rate for Indian power plants is based on operating station heat rate (2750 kcal/kWh for old plants and 2385 kcal /kWh for new subcritical PC, both lower heating value) given by the Central Electricity Authority as well as the calorific value of coal as given by The Energy and Resource Institute (4,000 kcal/kg). The CO_2 emissions were then derived from the amount of coal. Table 18 shows the results of the analysis.

Engineering and Technical Systems, and National Research Council. "Vision 21, Fossil Fuel Options For The Future." National Academy Press. Washington, DC. 2000. Pg 20.

[87] The generation cost for old plants comes from an Indian parliament, Lok Sabha, publication and the generating costs for the new subcritical PC and advanced technologies come from the Nexant study. The efficiencies are from the Nexant study and CEA publications. IGCC and ultra-supercritical PC combustion is predicted to have similar efficiencies in India. The actual efficiency of the IGCC plant is not known and this is an estimate when used with a class H turbine, which can operate at higher temperatures and higher efficiency. The cost estimates are for IGCC as given by the Nexant study in Table 15. 0.064$/kWh is found by averaging the levelized cost of a plant with a H turbine (0.061$/kWh) and that with a F turbine (0.067$/kWh).

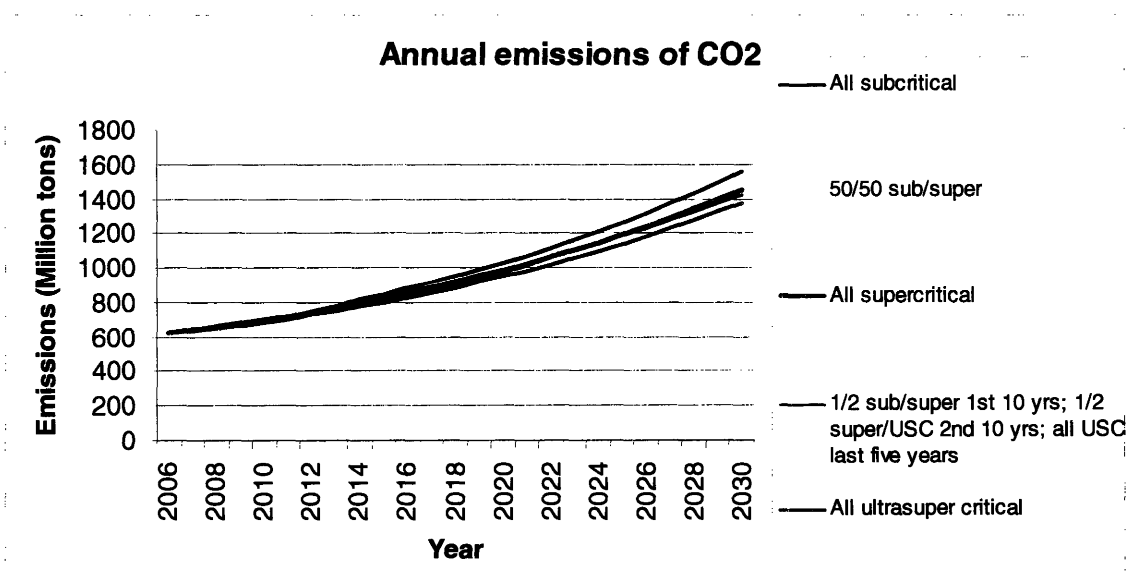
Table 18: CO2 Emissions predicted for advanced technology scenarios
(Total cost of generation based on total generation and levelized cost of generation = $1,160 billion)

Type of New Plant	Emissions mm tonnes CO_2	Coal Lock-in mm tonnes CO_2	Additional Costs US $
1. All sub-c PC	25,028	37,789	Base case
2. ½ sub-c PC, ½ SC PC	24,516	35,800	$37 billion
3. All SC PC	24,004	33,811	$75 billion
4. Staggered development	23,997	32,602	$80 billion
5. All IGCC	23,175	30,591	$150 billion

The results show that as you move to more efficient technologies, there are less CO_2 emissions. The following table shows that increasing plant efficiency by 4% by installing supercritical PC would reduce total emissions over 25 years by 4%. This is because the new plants would emit [(0.34 – 0.30)/0.30 = 0.13] 13% less emissions. An IGCC plant would reduce plant emissions from a subcritical PC unit by 27%. The analysis shows that total emissions over the 25 years are reduced by 7.5%.

The coal lock-in is defined here as the cumulative emissions from a power plant over its life, assuming a 40 year lifetime. The values shown in table 18 are the coal lock-ins for only the new power plants projected to be constructed as of 2005. If all new plants were subcritical PC, the new plants would emit a total of 37,789 million tonnes of CO_2 over the lifetime of the plants. Moving to supercritical PC would reduce these emissions by 11%. Moving to IGCC would reduce the total emissions from new plants by 19%. The following figure shows the emissions reductions for the scenarios.

Figure 26: Projected annual emissions of CO2 from coal-based power plants



This analysis showed the results of simply moving to more efficient technologies. A second option receiving great attention in the US is the capture and sequestration of CO_2 from a plant. This would reduce the emissions to near zero, but also reduces the efficiency. The benefit of IGCC is that, when combined with CO_2 capture, the reduction in efficiency is less than that when CO_2 is captured in a conventional PC plant. This is due to the relative purity of the synthetic gas in an IGCC plant as opposed to the very heterogeneous properties of the flue gas from the PC plant.

Capturing CO_2 requires the ability to sequester the CO_2, preferably underground. Efforts are underway by the National Geophysical Research Institite (NGRI) to make preliminary characterizations of sedimentary basins in India. It has plans to further explore the possibility of injecting CO_2 below Basalt formations. It has proposed a demonstration project of injecting 1,200 tons of CO_2 for 10 days and monitoring and modeling the results.[88] Before this happens, further characterization of basalt and rock formations is necessary. Julio Friedman, geologist at the Lawrence Livermore National Laboratory, believes that there are possibilities for sequestration in areas surrounding Calcutta, Mumbai, and the Himalayan basin, but this requires further exploration.

Drivers of IGCC

The costs have been shown to be significantly higher for IGCC than subcritical PC technology. The capital costs are estimated to be 60% more expensive and the levelized costs are estimated to be 33% more expensive for IGCC over new subcritical PC plants.[89]

The cost differential could be overcome by technical advances that reduce the cost of gasification, or by a third party, such as the Indian government or foreign parties, covering the difference in costs. The technical advances cannot be depended on in the near-term as utility-size gasification plants have not even been built yet, much less cost-saving tactics been developed.

The second option is to have a third party cover the difference in cost. A third party may do this to cover the cost of externalities. This will most likely come in one of two forms. The first is a global climate regime that creates incentives for incurring the additional costs of capturing and sequestering the CO_2 being emitted. Local governments may also choose to subsidize this as a method of reducing criteria pollutants such as SO_x, NO_x, mercury, and particulate matter. The environmental driver may be spurious as there are other options available to achieve the same ends mentioned here. These include switching of fuels and greater reliance on renewable energies.

A third party, such as the Indian government, may choose to cover the cost differential for another reason: the desire to ensure greater energy security or their desire to subsidize the development of BHEL's research project. Producing synthetic natural gas and synthetic transportation fuels from domestic feedstock could offset the imports of these products. This would require government subsidies, at least in the near-term to achieve economies of scale for the chemical production processes. Gasification is one method to do this, but it has yet to be proven as an efficient way to manufacture these chemicals in India. Furthermore, each type of gasifier has different characteristics that may make it particularly suited for specific applications. The final chapter of this thesis will focus on the technical aspects of gasification to understand how the process works and how it can produce a variety of fuels.

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[88] Kumar, B, G. Kalpana, D.J. Patil and C. Vishnu Vardhan. "Geological Sequestration of CO2 in Basalt Formations, Monitoring and Modeling: Indian Perspective". National Geophysical Research Institute, Hyderabad. August 2005.

[89] This is based on the estimates given in the Nexant study in tables 14 and 15. The capital costs for IGCC over new subcritical plants are estimated to be 60% more with a class H turbine and 80% more with a class F turbine. The levelized costs of generation for IGCC over new subcritical plants are estimated to be 27% more with a class H turbine and 40% more with a class F turbine.

6. GASIFICATION TECHNOLOGY

This chapter will evaluate the technical characteristics of various types of gasifiers. The Indian government-owned utility, NTPC, and manufacturer, BHEL, have chosen one technology to develop. Because BHEL is the largest supplier of equipment and because power generators tend to procure what is available to them, the decision made by BHEL will have a great influence on the technology used in the country. Other gasification technologies are available on the world market. However, these come from multinational corporations (MNCs) operating in developed countries with a higher cost basis. Secondly, the other technologies are not optimized for Indian conditions. This is important as Indian coals have significantly more ash than is present in coals in most developed countries.

This means that the decision India takes now is very important. In the following sections, the various technologies will be analyzed in order to determine their benefits and drawbacks. Special focus will be made on understanding the products derived in the gasifiers and the optionality inherent to the different types of gasifiers.

Gasification vs Combustion

The difference between a combustor and a gasifier is basically in the products and the complexity of operation and integration. In a combustor the char and volatiles, such as tars, in the coal are oxidized to produce heat that is transferred to a steam cycle for power.[90] In a gasifier, some volatiles are combusted and produce heat while another exothermic reaction occurs that converts char to syngas. The syngas is combusted in a gas turbine that provides power and excess heat is used in a steam cycle.

Air and coal, two inputs, are fed into a combustor. Air, coal, and steam, three inputs, are generally fed into a gasifier. The primary reactants are hydrocarbons consisting of hydrogen and carbon, and oxygen and nitrogen in the air. The primary products in combustion are CO_2, H_2O, and SOx and NOx. The following chart shows the products from combustion and gasification. (Additional products including methane are not shown as they are released in smaller quantities.)

Table 19: Products of coal-based technologies[91]

	Combustion	**Gasification**
Carbon	CO_2	CO
Hydrogen	H2O	H2
Nitrogen	NO, NO2	NH3, N2
Sulfur	SO2, SO3	H2S, COS
Water	H2O	H2

[90] Volatiles are molecules that vaporize first from coal. This leaves behind the char, which consists largely of carbon.

[91] Phillips, Jeff. "Gasification Combined Cycles 101." Presented at the Gasification Technologies Workshop in Bismarck, ND on June 28-29, 2006. EPRI. Online: http://www.gasification.org/Docs/Knoxville%20Pres/01Phillips.pdf.

In combustion, the goal is to maximize heat. In gasification, heat is necessary to start many of the reactions to realize the goal of creating syngas. The various chemical reactions that occur during these processes are shown below in table 20. A negative enthalpy is the maximum available energy in the form of heat that is *released* by the reaction. A positive enthalpy is the energy that is *consumed* by the reaction. The following chart shows the primary reactions occurring

Table 20: Enthalpies of formation that occur in coal combustion[92]

Coal $\rightarrow$ char + volatiles	
$C + \frac{1}{2} O_2 \rightarrow CO$	$\Delta H^O_{298} = -123$ kJ/mol
$C + O_2 \rightarrow CO_2$	$\Delta H^O_{298} = -406$ kJ/mol
Volatiles + $O_2 \rightarrow CO$ (and H2O)	
$CO + \frac{1}{2} O_2 \rightarrow CO_2$	$\Delta H^O_{298} = -283$ kJ/mol
$C + H_2O \rightarrow CO + H_2$	$\Delta H^O_{298} = -118.9$ kJ/mol
$C + CO_2 \rightarrow 2CO$	$\Delta H^O_{298} = +159.7$ kJ/mol
Hydrogenation:	
$C + 2H_2 \rightarrow CH_4$	$\Delta H^O_{298} = -88.4$ kJ/mol
Water Shift Reaction:	
$CO + H_2O \rightarrow CO_2 + H_2$	$\Delta H^O_{298} = -40.9$ kJ/mol
Methanation	
$CO + 3H_2 \rightarrow CH_4 + H_2O$	$\Delta H^O_{298} = -206.3$ kJ/mol
Pyrolysis:	
$4C_nH_m \rightarrow mCH_4 + (4n - m)C$	

The gasifier is similar to a combustor, but it creates an oxygen lean environment where some of the coal is combusted and the rest is oxidized to form gaseous fuels that can be combusted in a gas turbine or converted into chemicals. A gasifier generally forms the products listed in the table as well as additional products such as tars and other hydrocarbons.

Combustors tend to be simpler devices as their purpose is to heat water. Gasification is more complex in that the chemicals need to be controlled similar to an oil refinery. A combustion system has one steam cycle and a steam turbine. However a gasification system is an integrated system with a steam cycle and a gas turbine cycle. There are multiple heat recovery steam generators, compressors to pressurize the gasifier, and equipment to clean and separate products in the syngas.

The increased amount of equipment and the redundancy of equipment desired (e.g. a spare gasifier) increases the capital costs and makes the operations more expensive for IGCC over subcritical PC. The capital costs of IGCC can be decreased, not nearly to that of combustion, but decreased somewhat with

[92] Williams, A, M Pourkashanian, JM Jones, and N Skorupska. Combustion and Gasification of Coal. Taylor & Francis. New York. 2000.

less redundancy of equipment and a coherent, planned integration of equipment and systems. The tradeoff is that the availability of the system decreases with less redundancy. As the efficiency decreases, the revenue decreases. As the integration increases, the complexity of the system increases, decreasing availability because more time is needed for shut-down and maintenance.

This tradeoff between redundancy, integration, and costs is a parameter in the design of the gasifier. This needs to be considered in the design of the system. It also needs to be considered when choosing which type of gasifier, as the degree of complexity varies among gasifiers. Various institutions in India have chosen different types of gasifiers to utilize or study.

Gasification in India

Gasifiers are currently used commercially in India for chemicals production. The majority are commercially developed projects to produce fertilizer from various fuels such as coal, oil, and heavier oils. There are also gasifiers at research institutes where research is done on gasification for larger scale plants.

Gasification has been used commercially in India since 1963. Table 22 illustrates the feedstock and types of gasifiers. The purpose of these plants was to produce ammonia from hydrocarbons. The fuels vary from coal to naphtha to lignite. The gasification processes used are mainly entrained flow gasifiers developed by major corporations such as Shell and Texaco. These are gasifiers that were sourced from outside the country. While there were gasification processes that ran on coal, many have ceased operations. The coal-based gasifiers were a Koppers-Totzek system which is a dry-feed entrained flow gasifier.

Table 21: Major gasification plants to produce ammonia/urea[93]

Location	Year Commissioned	Year Closed	Feed	Gasifier used
Owned by Fertilizer Corporation of India (FCI)				
Ramagundum, AP	1980	1999	Coal	Koppers-Totzek
Talcher, Orissa	1980	1999	Coal	Koppers-Totzek
Sindri, Bihar	1979	N/A	Fuel Oil	Shell
Gorakhpur	1969	1976	Naphtha	Shell
Owned by Neyveli Lignite Corporation (NLC)				
Neyveli	1963	1979	Lignite	Winkler
Owned by Gujarat Narmada Valley Fertilizers Company				
Bharuch	1982	1991	Vacuum Resid.	Texaco

[93] Chen, Tan-Ping. "Effects Of Coal Ash Content On Cost Of Generation For IGCC Power Plant."

Owned by National Fertilizer Limited (NFL)

Batinda	1979	N/A	Fuel Oil	Shell
Panipat	1979	N/A	Fuel Oil	Shell
Nangal	1979	N/A	Fuel Oil/Naphtha	Shell

This shows that there is operating experience in India with smaller gasifiers meant for chemicals production. Many of the coal-based gasifiers have been shut down after 20 years of operation. The state of operations during these 20 years and the reasons for closing the plants are not known. One possibility is that the plants may have operated successfully and reached the end of their economic lifetime. Economics may have driven a switch to natural gas, a less complex hydrocarbon, or to a more efficient process.

The processes shown here are all commercially-proven gasifiers developed by multinational corporations. They are used in many countries around the world. For example, Shell also has many coal gasification plants in China for the purpose of fertilizer production.

Separate from this gasification experience is the development of a larger-scale gasifier for electricity production. BHEL, the central-government owned heavy equipment manufacturer, is working to develop a gasifier. It has two test bed gasifiers: a 6.2 MW (150 tonnes of coal per day or tpd) fluidized bed gasifier located in Trichy and a smaller, 18 tpd fluidized bed gasifier in Hyderabad. Research was initiated on a moving bed gasifier in Trichy. It was determined that a fluidized bed gasifier was better suited to its research goals and the gasifier was retrofitted to become a fluidized bed gasifier.

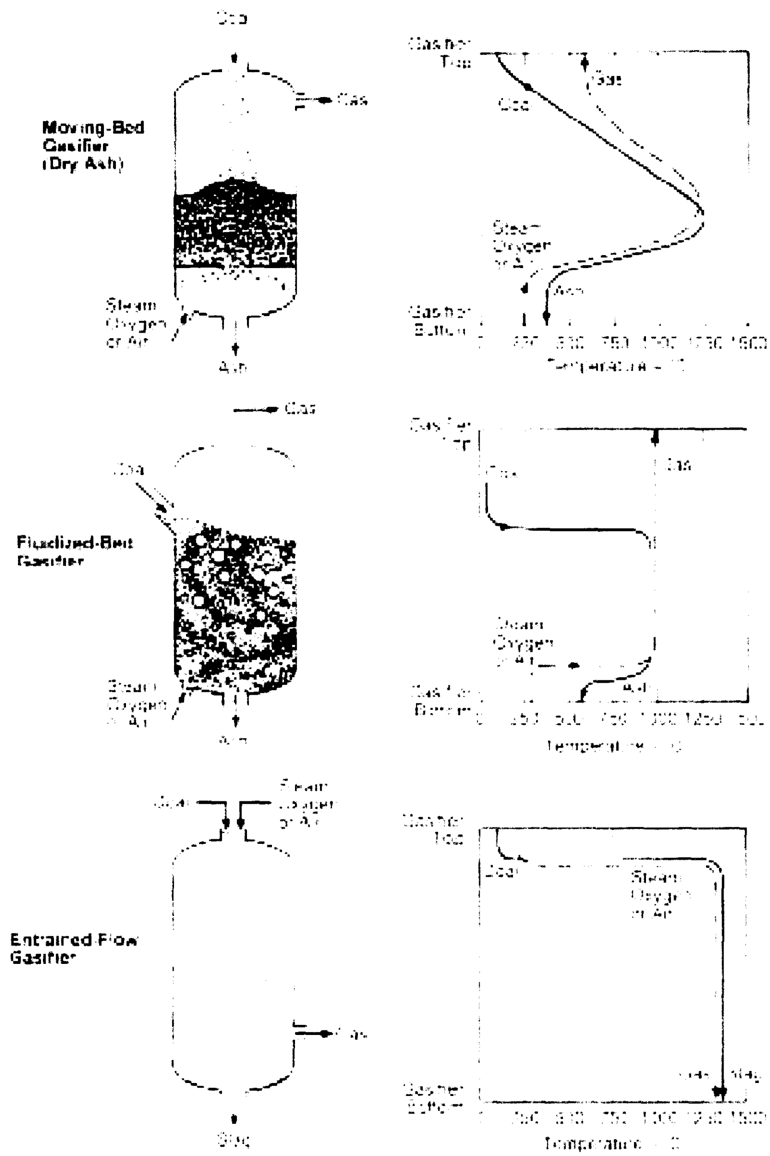
In addition to BHEL, there are two other government-sponsored research agencies developing gasification technology. The Central Fuel Research Institute has two gasifiers: a 2.6 tpd entrained bed gasifer and a 19 tpd moving bed gasifier. The Indian Institute of Chemical Technology (IICT) at Hyderabad had a 24 tpd Lurgi moving bed gasifier. Operation was discontinued in 1983. IICT has begun research on hot gas cleanup in parallel with research activities by BHEL.

Looking ahead, BHEL hopes to partner with these agencies to fulfill its grand vision entitled Coalplex. The goal is to develop a pressurized fluid bed gasifier able to produce electricity, synthetic natural gas, liquid fuels, chemicals, and hydrogen by 2020. Success of this program will require a much larger investment by BHEL than what was done until now.

Types of gasifiers

Gasifiers are generally divided into three categories. The major difference between the three types of gasifiers is the inlet velocity and pressure of the air. This affects the residence time of the coal in the gasifier, the size of coal particles required, and the heat removal, among other things. The three types of gasifiers are shown in figure 27.

Figure 27: Three major types of gasifiers[94]



In a moving bed gasifier, the coal sits in the gasifier for up to an hour while slowly pyrolysing and gasifying. This creates a large temperature gradient from the top to the bottom of the gasifier. The term moving bed is usually used synonymously with fixed bed.

The most uniform temperature distribution is found in the second type—the fluidized bed gasifier. The particles are combined with a large amount of inert material and the whole bed is fluidized within the gasifier. This creates very uniform conditions within the gasifier. There are three subcategories of fluidized bed gasifiers, listed in order of inlet air velocity: stationary or bubbling fluid bed, circulating fluid bed, and transport gasifier. The stationary fluid bed has a circulation zone near the bottom of the gasifier. The circulating bed's circulation zone fills the entire gasifier, creating the most uniform

[94] Holt, Neville. "Gasification Process Selection- Trade-offs and Ironies". EPRI. Presented at the Gasification Technologies Conference 2004 October 3-6, 2004, Washington, DC. Online: http://www.gasification.org/Docs/2004_Papers/30HOLT_Paper.pdf.

temperature gradient. The transport gasifier operates at higher circulation rates, velocities, and riser densities than the stationary fluid and circulating fluid bed gasifiers. This results in the shortest coal residence time among the fluidized bed gasifiers. Transport gasifiers can be agglomerating whereby there is a location for collection of heavy particles to facilitate removal.

The entrained flow gasifier operates at the highest temperatures and the coal is quickly heated and gasified almost as soon as it enters the gasifier. It operates at a fairly consistent temperature. However there is not perfect mixing within the gasifier and there are localized spots of higher and lower temperatures.

For all types of gasifiers there are design parameters that can be adjusted. The oxidant can be air or O_2 generated from an air separation unit. Dry coal can be fed into the gasifier directly or coal can be fed as a slurry in water. The reactor wall may be a jacket, a membrane, or a refractory wall. The hot syngas needs to be cooled before being cleaned. The methods for cooling include water quench, gas quench, and syngas cooler.

The following chart shows the varying operating characteristics of the three gasifiers. The feed coal particles are largest for the moving bed gasifier.

Table 22: Properties of Gasifiers[95]

	Moving Bed (Fixed Bed)	Fluidized Bed (Transport)	Entrained Flow
Feed coal characteristics (size)	5-80 mm	5-10 mm	< 0.1 mm
Outlet gas temperature	400-700°C (parts of gasifier up to 1000°C	900-1100 °C	1200-1600°C
Residence time	30-60 min	0.5-3 min	1 sec
Pressure	25-30 bar	30 bar	20-70 bar
Gas velocity	1180-1340 kg steam / kNm^3 $CO + H_2$ (least for lignite, then anthracite, most for bituminous) 170-300 Nm^3 oxygen / kNm^3 $CO + H_2$ (O_2 consumption increases as coal quality increases)	5-8 m/s (circulating fluid bed gasifier) 11-18 m/s (KBR transport gasifier)	5 m/s
Methane and tar production	Greatest	Middle	Least
Commercial uses[96]	Syngas production that is converted to Fischer-Tropsch liquids. A slagging version (less common) is used for methanol and power production as operates at higher temperature and less methane production. Can be used as a slagging gasifier, but less common. Lurgi commercially used in South Africa for fuel production	Circulating fluid bed: 70 HT Winkler plants have been built and all have ceased operation for economic reasons. Foster Wheeler. Transport gasifier: GTI U-Gas has plants in China. Piñon Pines in US was KRW and never operated. KBR	Dry-feed: Shell, Prenflow, Noell Slurry-feed: GE (Texaco), E-Gas

[95] Higman, Christopher and Maarten van der Burgt. "Gasification". Elsevier, USA. 2003.

[96] "The 2004 World Gasification Survey shows that existing world gasification capacity has grown to 45,001 megawatts thermal (MWth) of syngas output at 117 operating plants with a total of 385 gasifiers. Coal remains the predominant feedstock, accounting for 49% of syngas capacity generated from all feedstocks. Petroleum provides 37%, with the remaining 14% of gasifier feedstocks coming from natural gas, petcoke, and biomass/wastes. The primary product of operating gasification plants is synthesis gas (or syngas) from which other marketable products are generated, including chemicals (37%), Fischer Tropsch liquids (36%), power (19%), and gaseous fuels (8%). Three commercially-proven technologies currently command 94% of the 2004 world market: Sasol Lurgi technology represents 41% of the gasification operating production capacity, GE Energy (formerly Texaco) represents 34% of reported capacity, and Shell technology represents 19%." Source: National Energy Technology Laboratory (NETL), U.S. Department Energy. <u>2004 World Gasification Survey</u>. 2004. Online: http://www.netl.doe.gov/publications/brochures/pdfs/Gasification_Brochure.pdf.

One additional benefit arising from fluid bed gasification is based on the operating experience of an entrained flow gasifier in the US. A report from the Department of Energy states "The most significant problem encountered in this project was the lower than expected carbon conversion in the gasifier, which required recycling fly ash to the gasifier and increased oxygen requirements. Because of the effect of low carbon conversion on performance, the project did not quite meet its objective of demonstrating improved overall efficiency and cost effectiveness compared to conventional coal-fired power plants."[97] The fluid bed gasification technology already incorporates this recycling of fly ash as part of its normal operation.

Thermodynamics

The process of gasification breaks down larger hydrocarbon molecules into smaller molecules such as H_2, CO_2, CO, H_2O, H_2S, SO_x, NO_x, CH_4, NH_4, etc. The ratio of these products depends on many factors: the temperature, pressure, residence time, and direction of air flow. Varying these factors can change the mix of products that is created. In general, pure syngas is comprised of CO and H_2. The purer the syngas, the easier it is to capture the CO_2, harness the hydrogen, or manufacture chemicals.

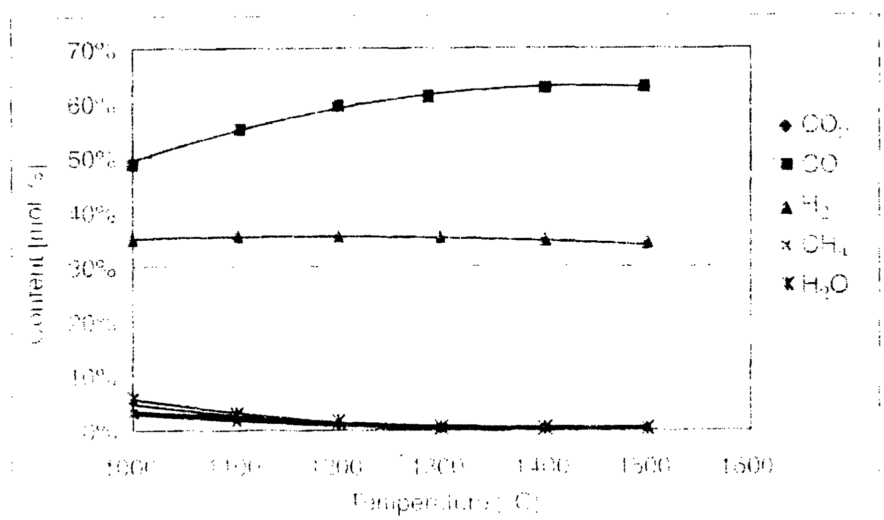
Temperature and pressure are two variables that must be considered during gasifier design and during operation. These variables can be optimized for a specific type of gasifier in specific ambient conditions, but also for the desired end product, whether that be electricity, chemicals, syngas, or liquid fuels.

There are limits on allowable temperature. Gasification must occur at a minimum temperature above the reaction temperature. Once at steady state, the chemical reactions for gasification are exothermic and provide enough heat to maintain this minimum temperature. This is why some gasifiers may produce syngas that is almost entirely H_2 and CO. All the char and tar is gasified in this case and combustion is kept to a minimum.

In general, increasing temperature means that more tars and char are gasified and less tar is carried out in the gas stream. The proportion of CO increases while products such as CO_2 and CH_4 decrease with increasing temperature. The following chart shows generally the products in a gasifier at 30 bar pressure as the temperature varies. Increasing temperature increases the output of CO, while H_2 remains constant and CO_2, CH_4, and H_2O decrease.

[97] NETL. "Clean Coal Technology: Tampa Electric Integrated Gasification Combined-Cycle Project."

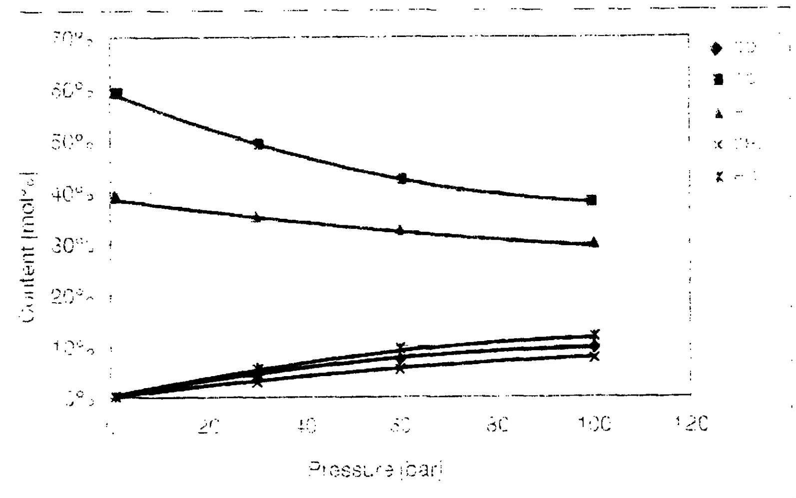
Figure 28: Variations of syngas compositions with temperature (pressure at 30 bar)[98]



To run the gasifier at higher temperatures, more oxygen is required. This requires a larger air separation unit. The temperature affects other factors beyond products. Each coal has a different ash-slagging temperature. The decision to slag or not slag the ash is a consideration when setting the temperature. Additionally, there is an upper limit to the temperature at which the materials used in the gasifier and peripherals could fail.

The pressure of the gasifier is also an important factor. Demonstration plants have generally operated at 30-40 bar with the maximum demonstration at 100 bar. The chart below shows how the products vary at various pressures in a gasifier at 1000°C. The CO and H_2 yields generally decrease while the CO_2, CH_4, and H_2O increase. The methane production doubles as pressure increases from 25 bar to 95 bar.

Figure 29: Variations of syngas compositions with pressure (temperature at 1000oC)[99]



[98] Higman, Christopher. "Gasification".
[99] Higman, Christopher and Maarten van der Burgt. "Gasification". Elsevier, USA. 2003.

Decreasing the proportion of CO and H_2 to other products is generally not desirable in a gasifier. But there are other reasons to drive higher pressures, mainly scale. At higher pressures, the system is more compact requiring a smaller size gasifier and peripherals. Additionally, higher pressures are needed for the gas turbine and some gas clean-up and CO_2 capture. The gas turbine requires pressure at 20-40 bar. Methanol and ammonia are synthesized at 50-200 bar. It takes less energy to pressurize the reactants as opposed to the product syngas.

There are a few factors that can vary in the design, as opposed to the operation, of the gasifiers. Gasifiers can be dry or slurry fed (coal mixed with water); up or down flow (direction of air flow); jacket, membrane, or refractory reactor wall; gas quench, water quench, syngas cooler for syngas cooling; oxygen or air for the oxidant.

Products

The optionality inherent in gasifiers is that they can run on a range of fuels and can produce a range of products. The feedstocks include coal, liquid residues, natural gas, biomass, and waste. The products include ammonia, methanol, carbon monoxide, hydrogen, oxo alcohols, fischer tropsch (F-T) liquids, synthetic natural gas, town gas, reduction gas, and gas turbine fuel. Many chemicals can be synthesized from coal: ethylene, methanol, formaldehyde, acetic acid, ethylacetate, alpha-olefins, waxes, solvents, paraffin, ketones, alcohols, and acids. [100] The majority of gasification plants were developed for syngas production as a chemical feedstock or for F-T fuels:

Table 23: Share of products from world-wide gasification plants[101]

Product	Share of gasification production
Chemicals	37%
Fischer Tropsch liquids	36%
Power	19%
Gaseous fuels	8%

Currently, F-T production is commercialized at Sasol in South Africa. Synthetic natural gas (SNG) is produced from coal in Beulah, North Dakota. There are many gasifiers converting coal to ammonia (for fertilizer production) in the world, including multiple ones in China.

Of the three types of gasifiers, each has specific benefits and drawbacks related to the gasification of specific fuels and the production of certain products. Indian environmental conditions, knowledge within the country, and its coal characteristics should be considered in determining which fuels are most available and which products have the highest demand in India.

While a few products have seen development, there are a range of possibilities available. The products desired depend on the needs of India. There is pressure in India to achieve greater energy independence, which would be greatly aided by the ability to produce necessary products from their coals. The products are listed below.

[100] http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/2_3_28.asp#Heading8
[101] NETL. 2004 World Gasification Survey

Table 24: Products from IGCC[102]

Electricity

Maximum efficiency and high levels of syngas (H_2 and CO) are desired for power production. The idea is to maximize throughput and create the most products that can be burned in a gas turbine and then use the residual heat in a heat recovery steam generator and steam turbine. Generally this is accomplished with an entrained bed gasifier. The entrained bed gasifier has the shortest residence time meaning the fastest throughput of material and the smallest gasifier necessary. It also creates the most pure syngas—useful for gas clean-up before combustion in a gas turbine.

F-T for liquid fuel production

Diesel ($C_{12}H_{26}$) can be produced to replace gasoline or diesel. The fischer-tropsch process first is a shift reaction that combines one CO with 2 H_2 to form CH_2 and water.

$$CO + 2H_2 \rightarrow -(CH_2)_n- + H_2O$$

This requires a ratio of 2 H_2 to one CO. As the previous charts have shown, there is more CO in the reactant gas than H_2. to get the additional hydrogen, a water gas shift reaction is carried out:

$$CO + H_2O \rightarrow CO_2 + H_2$$

Finally, the CH_2 is refined to the desired product. This process requires pure syngas in the form of CO and H_2 with the maximum H_2. There is not much empirical evidence to make a judgment on which gasifier is best for this. The majority of experience with fuels production is Sasol in South Africa using a moving bed gasifier.

Methane and methanol

Methane (CH_4) production is useful to take advantage of existing natural gas infrastructure and for storage, as well as being a clean fuel to burn. Methanol can be stored more easily as it is in liquid form, but it requires an additional oxygen molecule. Methanol can be used as a feedstock for ethanol and other chemicals. For methane, the desired ratio of H_2 to CO is 3 to 1:

$$CO + 3H_2 \rightarrow CH_4 + H_2O$$

The syngas generally produces more CO than H_2. This is beneficial for methanol production as it requires two molecules of hydrogen as opposed to three.

$$1\ CO + 2\ H_2 \rightarrow CH_3OH$$

H_2

Hydrogen is currently used in refineries and in the food industry. Future uses could include fuel cells in automobiles. Hydrogen can be burned directly in the gas turbine or put into storage and transport for use in a fuel cell. When H_2 is removed from the syngas of a coal gasification plant, the remaining material is CO_2, which can be captured and stored. Fuel cells can also operate on methane and it is important to determine which is most efficient.

CO_2 for capture

[102] Ibid.

Capturing CO_2 reduces the efficiency of any power generation technology. The advantage of IGCC in this respect is that the CO_2 is more concentrated in syngas, resulting in lower efficiency losses than that required for capture with combustion. For combustion, advanced flue gas treatment, CO_2 separation, capture, and compression is required. For gasification, water gas shift, separation and capture is required.

There is a significant difference in efficiency and costs if the plant is configured and constructed capture-ready versus when it is not. For this reason, it is useful to design the plant with this in mind or with built-in capabilities that enable easy configuration in the future.

NH_3 for chemicals
Ammonia is a product that can be used as a feedstock for chemicals and fertilizer production. Ammonia is one of the most widely manufactured chemicals in the world. It is formed by combining one nitrogen molecule with 3 hydrogen molecules:

$$N_2 + 3\ H_2 = 2\ NH_3$$

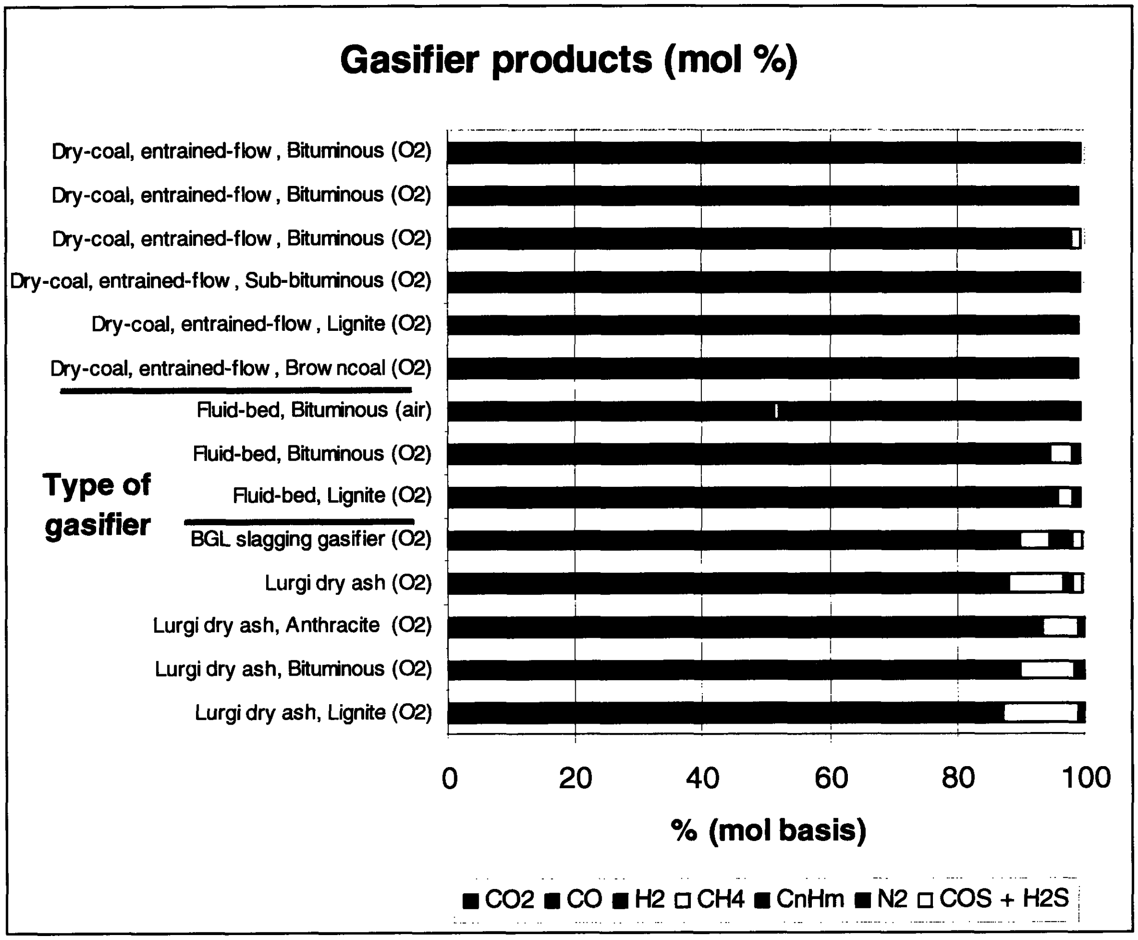
Over 150 million tonnes/yr of ammonia is produced globally. 90% of this comes from natural gas with the remainder derived from coal and heavy oil. India forms a large part from naphtha. Ammonia is best formed at low temperatures and the synthesis occurs from 130 to 150 bar. Three coal-based ammonia synthesis plants have operated in India.

Evaluation of gasifiers

Each type of gasifier has qualities and drawbacks that make it best suited for specific circumstances. This evaluation will look at these circumstances.

An important consideration is the products of the gasifiers to determine which gives the purest syngas (CO and H_2). The following chart shows the syngas compositions as measured from existing plants:

Figure 30: Final syngas composition from existing gasifiers (mol %)[103]



Entrained flow gasifiers yield high concentrations of CO and H_2. This makes sense when considering the temperature analysis. The entrained flow gasifier operates at the highest temperature: thus yielding the purest syngas. The second purest is fluid bed gasifiers. The least pure syngas comes from a moving bed gasifier. The moving bed gasifier also produces the most tars in the syngas.

Tars are present in the syngas when the temperature is not hot enough to volatize the tars. This happens in fluid bed and especially moving bed gasifiers, where the temperatures are lower. This is most significant in the moving bed gasifier. This is because pyrolysis happens as the coal is on the top of the bed in the cooler region. The temperature increases as the coal moves down in the bed. However tars are formed near the top of the bed and many of these tars are carried out with the syngas before they are able to sink to the bottom and devolatize. This is one drawback to a moving bed gasifier. Table 25 on the following pages lists more benefits and drawbacks to the three main type of gasifiers.

[103] Higman, Christopher. Gasification.

Table 25: Comparison of properties of a moving bed, fluid bed, and entrained flow gasifiers[104]

	Moving Bed (Fixed Bed)	Fluidized Bed (Transport)	Entrained Flow
Subcategories	Two names usually used synonymously for same gasifier: moving bed and fixed bed.	Three types: stationary fluid bed, circulating fluid bed, and transport gasifier. Stationary fluid bed—similar to a bubbling fluid bed, Winkler process. Lower velocity. Circulating fluid bed—Higher circulation rate (velocity) than stationary, which means particles heat faster, less tar formation. Offered by Lurgi and Foster Wheeler. 5-8 m/s gas velocity. Transport gasifier—11-18 m/s gas velocity. Highest throughput and circulation rates. KBR offers this. Agglomerating gasifier—similar to transport, but allows a location for agglomeration so that the heavy particles can fall out. This is developed by KRW and GTI's U Gas technology.	Differences arise from how and where the feedstock is introduced into the gasifier.
Products	Most methane and tars production	Medium methane and tars production	Least methane and tars production
Feed coal characteristics (size)	5-80 mm	5-10 mm	< 0.1 mm
Outlet gas temperature	400-700°C (parts of gasifier up to 1000°C	900-1100 °C	1200-1600°C
Residence time	30-60 min	0.5-3 min	1 sec
Pressure	25-30 bar	30 bar	20-70 bar
Gas velocity	1180-1340 kg steam / k[N]m^3 CO + H_2 (lowest velocity required for lignite, then anthracite coal, highest velocity required for bituminous coal) 170-300 [N]m^3 oxygen / k[N]m^3 CO + H_2 (O_2 consumption increases as coal quality increases)	5-8 m/s (circulating fluid bed gasifier) 11-18 m/s (KBR transport gasifier)	5 m/s

[104] Williams, A. Combustion and Gasification of Coal.
Higman, Christopher. Gasification.

	Moving Bed (Fixed Bed)	Fluidized Bed (Transport)	Entrained Flow
Commercial uses	The production of syngas that is converted to Fischer-Tropsch liquids. This is commercially done in South Africa. A slagging version (less common) is used for power production as it operates at higher temperature and produces less methane.	70 Winkler plants have been built and most have ceased operation for economic reasons. GTI has plants in China. Piñon Pines IGCC plant in US was a KRW gasifier, but it never operated.	Shell gasifier used commercially world wide for chemicals production. Two demonstration plants currently operating in the United States.
Advanced designs		Have coal fed into pyrolyser, where it mixes with air and receives heat from the combustor. There the coal is separated into char and tar. The tars and gases are sent to a combustor for combustion to create heat. The chars are sent to a gasifier and are gasified with only steam added and heat from the combustor. This would create pure gas without the need for an ASU to obtain O_2. This means the gasified reactants are free of tars and there is a complete carbon conversion.	GE developing gasifier to be used with lower quality fuels.

	Moving Bed (Fixed Bed)		Fluidized Bed (Transport)		Entrained Flow	
Factor	Benefits	Drawbacks	Benefits	Drawbacks	Benefits	Drawbacks
Level of commercialization	Sasol Lurgi technology comprises 40% of world gasification production capacity.			While there are some plants in operation, there is not a high level of demonstration.	GE (formerly Texaco) and Shell technologies comprise 53% of world gasification production capacity. This type of gasifier most demonstrated in the West for power production	
Oxygen consumption	Oxygen consumption is very low.					High temperatures and slagging require more O_2

	Moving Bed (Fixed Bed)		Fluidized Bed (Transport)		Entrained Flow	
Factor	Benefits	Drawbacks	Benefits	Drawbacks	Benefits	Drawbacks
Steam consumption		High steam demand				
Temperature	Outlet temperature of gasifier is low—requires lower reduction in temperature for gas clean-up.	Longest residence time: most difficult to control temperature. If no slagging—solid particles build up on walls.		Temperature limited to slagging temperature of ash in the coal.	Shortest residence time: easiest to control temperature.	
Coal types	Operates on lump coal—no need for grinding.	Can not use with fines (smallest coal particles), which are generally present the more modern the mining application. Heavily caking coals cannot be used.	Prefer high ash-slagging temperature. Suited for low rank coals or biomass.	Too many fines (smaller coal sizes) will choke the system.	Prefer coals with low ash-slagging temperature.	
Synthesis gas	Good for ammonia production.	Pyrolysis products are present in the product synthesis gas. Lower temperatures mean formation of larger molecules, such as CH_4, and less pure syngas. This is not good for CO_2 capture nor for synthesis fuels (F-T, H_2, etc.).	Even distribution of heat and material in the gasifier—prevents unwanted pyrolysis.	Lower temperatures mean formation of larger molecules, such as CH4, and less pure syngas. This is not good for CO2 capture nor for synthesis fuels (F-T, H2, etc.). Can only achieve carbon conversion of 97% as opposed to 99% for entrained flow gasifiers because unreacted carbon will leave with ash.	Higher temperatures mean less formation of larger molecules, such as CH4, and more pure syngas. This is good for CO2 capture and for synthesis fuels (F-T, H2, etc.).	

	Moving Bed (Fixed Bed)		Fluidized Bed (Transport)		Entrained Flow	
Factor	Benefits	Drawbacks	Benefits	Drawbacks	Benefits	Drawbacks
Slagging (melting of the ash)		Large temperature variation results in high temperature zones with slagging	No slagging			High temperatures leads to slagging, creating larger energy penalty the larger the ash and moisture content of the coal
Gasifier dimensions		A long residence time requires largest sized gasifier.	Smaller than a moving bed gasifier.	Larger than an entrained flow gasifier.	Shortest residence time—smallest gasifier.	
Technical complexity		More moving parts in the gasifier, such as stirrer. Tars in the synthesis gas requires more complex clean-up.		Carbon conversion limited due to coal particles leaving with the syngas—requires increased cycling, use of secondary combustor, or disposal of unconverted coal The steam and air inlet velocities serve two functions in this gasifier—the reactant and the fluidizing medium. This complicates the operation.	Least complexity. GE and Bechtel have decreased the integration of the systems to increase the availability.	
Operation			Extremely good mixing of feed and oxidant	Requires constant monitoring	Slagged ash may be easier to deal with	
Environmental control		Environmental controls done to syngas.	Limestone as inert bed material captures sulfur (turns into gypsum), but not easy to optimize as it is junior to gasification optimization.			Sulfur removal must be done to syngas.
Other fuels	Has been used with a variety of fuels.		Has been demonstrated with biomass and waste.			Generally requires high quality coal.

The previous factors compare general characteristics of gasifiers. What is most important is to note the relation to India's needs and characteristics. What is continuously stressed as the most important factor is the quality of Indian coal: specifically high ash.

While moving bed gasifiers are proven for chemicals production, they are not feasible (based on size limitations) for the large scale power generation needed to fuel India's development. Moving bed gasifiers tend to be small—under 100 MW. To be competitive in power generation, the gasifiers need to approach the size of combustors—500 MW in India. With a residence time of 30 minutes in a moving bed gasifier, as opposed to 5 minutes in a fluid bed gasifier, the moving bed gasifier would have to be 6 times as large to produce the same amount of electricity. This would significantly increase the capital costs.

Thus the comparison becomes one between a fluidized bed gasifier and an entrained flow gasifier. This is more difficult as each is attractive for different reasons. On a macro scale, entrained flow gasifiers are in wider commercial use, meaning there is more proven experience. They also have shorter residence times, meaning faster throughput and smaller gasifiers.

However, BHEL has balked at using entrained flow gasifiers due to Indian coals having 40% ash content. This means that 40% of the coal would slag—requiring a lot of energy and also requiring sophisticated systems to handle this melted ash. This is the reason that a fluid bed gasifier was chosen. The ash does not slag and the solid ash is easier to deal with. Additionally, sulfur can be removed with limestone in the gasifier.

While fluid bed gasification has not been proven commercially viable, it is not out of the running. Coal combustion experts Janos Beer, professor emeritus MIT, and Adel Sarofim, professor of chemical engineering at the University of Utah, agree that fluid bed gasification has promise and accept its usefulness with high ash coals.

Fluid bed gasification would be a good choice if India wants to have many installations producing many fuels. This would allow them to use their Indian coal to produce power and chemicals, displacing imported oil and gas. This is the method currently proposed by the Indian institutions.

A second option is to develop an entrained flow gasifier that works with higher-quality imported coal. As India is forecasted to import more coal in the future it may make sense to develop the best technology (gasification) for the best fuel (imported coal). However, this is not a solution for India's desire to achieve greater energy independence.

CONCLUSION

This thesis has looked at current energy policy in India and how it relates to coal. This survey was done to understand how advanced, coal-based power generation technologies could be adopted in India. Supercritical PC was used as a case study for adoption of a new technology. The benefits and drawbacks of gasification technology were reviewed to understand what aspects of the technology are relevant to conditions in India and Indian government policies.

Gasification is a power generation technology that is attractive due to its predicted higher efficiencies and the optionality it provides. It can produce a variety of products, such as electricity, liquid fuels, synthetic natural gas, and other chemicals. Studies have estimated that capturing CO_2 from an IGCC plant has a lower efficiency hit than that for subcritical PC plant. This is valuable to India, whose transportation fuels and natural gas largely come from imports priced at the world market price.

Gasification is quite different in India than the US. The different characteristics of the Indian coals require a gasifier that can handle large ash and moisture contents. The higher atmospheric temperatures in India mean that plants theoretically run at a lower efficiency. Differing costs of capital, funding sources, and government policies mean that the same type of plant would have different costs in the US and India. Additionally, the operating experience and structure of the energy sector is much more centralized than in the US.

In the US, some new technologies in the energy sector, like gasification, are driven by government policies that provide subsidies to demonstrate and commercialize. In India, new technologies are disseminated not through explicit subsidies offered by the central government, but by actions taken by the central government-owned generating company, NTPC. While NTPC is supposed to operate independently, the decisions they take are not strictly economical. They take an aggressive stance on new technologies—which drove commercialization of larger unit sizes of subcritical PC technology and implementation of supercritical PC technology.

While NTPC is supposed to operate independently of the central government, they are not immune to its influence. In addition, NTPC lobbies the government for policies that benefit their own objectives. One example is the special law for mega power projects. Under this law, plants have to pass fewer licensing steps and are allowed reduced import duties—both valuable to NTPC's plans to install large mine mouth coal plants.

NTPC is a focal point for technology dissemination in India. While they are currently exploring the possibility of constructing a 100 MW IGCC demonstration plant, further commercialization will require some additional type of central government driver.

This would require the central government to determine that there is potential value in installing this technology in India. This is a hard decision to take as it requires a risky technological endeavor as the IGCC technology that is best suited for the Indian context is different than what is used in the rest of the world. (USA and Europe choosing entrained flow gasification and South Africa using moving bed gasification).

The main obstacles to the increased use of gasification in India are the cost differential relative to conventional coal combustion systems and the technological uncertainty. Additionally, reforms in the coal mining sector need to be successfully realized to increase the supply of coal to warrant new plants. If these obstacles are overcome and the large government organizations continue to push for this technology, gasification will be adopted in India.

The cost differential may be overcome through a variety of means. Technological advances may reduce the costs over and above the cost reductions that can be achieved through economies of scale, but this is a longer term viewpoint and is speculative. The higher costs could be subsidized by a third party. The Indian government may choose to do this for local pollution control or as a way to commercialize a technology with the ability to produce transport fuels to replace imports. Foreign organizations or countries may pay the differential as part of their carbon offsets.

The technological uncertainty is being countered through research efforts by BHEL. However, progress is slow and there have been no great advances in the research in recent years. NTPC wants to move ahead with a 100 MW demonstration plant and may be willing to procure it from overseas. NTPC had procured supercritical PC from overseas rather than purchasing from BHEL. After purchasing equipment for two plants, NTPC balked at new orders, seemingly waiting for BHEL's deployment of its supercritical technology.

So as far as importing or developing gasification technology is concerned, history suggests that there is a scientific propensity and drive in India to develop and deploy indigenous technologies. As the foreign fluid bed technologies have not been demonstrated at large scale (unlike supercritical PC technology), this makes it even more likely that the indigenous technology route will be chosen.

What is the possibility that India will acquire the more extensively deployed entrained flow gasifier? This seems unlikely as most institutions in India support fluid bed gasification. For now, the Indians will wait to see the success of the other types of gasification technology used overseas. It may, in the end, be western firms who bring this technology to India via carbon offsets, to be used with imported coal.

Should India adopt and emphasize gasification? India does not have enough coal for its existing power plants and it does not have enough power plants to meet its existing electricity demand. Having the coal available in the near term or middle term to produce synthetic fuels seems unlikely. In terms of technology, many state generation companies have trouble operating subcritical PC plants, much less building and operating supercritical PC plants. IGCC is not in the horizon of their capabilities. For the environmentalists, sequestration ability is nascent in India. On the other hand, there are multiple efforts looking into increased use of biomass for power and transport fuels. This may be a better option to turn to for CO_2 emission abatement.

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Appendix A: Environmental Regulations

Environmental regulation for Indian coal-based power plants as mandated by the Central Pollution Control Board. State pollution control boards are required to implement these standards or stricter ones.

Environment (Protection) Rules, 1986

- Condenser cooling waters (once through cooling system): pH 6.5-8.5, not more than 5° higher than the intake water temperature.
- Ash pond effluent: pH 6.5-8.5. Suspended solids 100 milligramme/litre. Oil and grease 20 mg/l.
- Particulate matter emissions: >210 MW: 150 milligramme per normal cubic meter. <210 MW: 350 milligramme per normal cubic meter.
- Minimum stack height: >500MW: 275 m. 200MW—500 MW: 220 m.
- Seawater cooling: temperature of water near exit may not rise more than 7°C.
- Change in temperature of cooling water from inlet to the outlet of the condenser shall not be more than 10°C difference

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- No person shall within a radius of 100 kilomenters from coal or lignite based thermal power plants, manufacture clay bricks or tiles without mixing at least 75% fly ash (100% by 31 August 2007).
- All construction of buildings within 50 km of a thermal plant should use blocks with 100% (by volume) of bricks
- All coal or lignite based thermal power plants shall utilize the ash generated in the power plants as follows:
    - Make available ash...without any payment or consideration, for the purpose of manufacturing ash-based products such as cement, concrete blocks, bricks, panels or any other material or for construction or roads, embankments, dams, dykes or for any other construction activity.
    - Have 100% fly ash utilization by 2008 (no dumping on lands) (if plant is commissioned subject to environmental clearance plant for full utilization of fly ash)
    - Have 100% fly ash utilization by 2014 (no dumping on lands) (all plants not falling under previous comment)

BIOGRAPHICAL INFORMATION

Lori Simpson is a National Science Foundation fellow at MIT. She graduated in September 2006 with a Master of Science degree from the Engineering Systems Division in Technology and Policy. As a researcher in the Laboratory for Energy and the Environment she participated in the MIT Coal Study, working alongside over 10 professors and various graduate students to produce a publication giving recommendations to US policy makers. Her part in the study was to look at India's coal use and policies to understand synergies between Indian coal-based generation technologies and US generation technologies.

Before attending MIT, Lori has worked as independent consultant on RFID technology for Nebraska feedlot operators, as an engineering intern in the Indian Health Service, and as a researcher for the engineering summer program called Washington Internships for Students of Engineering. As an undergraduate student at the University of Nebraska Lincoln, Lori received bachelor's degrees in Mechanical Engineering and Spanish with minors in Studio Art and Mathematics. She tutored engineering mechanics courses, did research on a shear stress sensor for jet airplanes, and was a mentor in the Latino Achievement Mentoring Program.

Outside of work and academics, Lori skis, travels, and pursues interests in foreign affairs. She has climbed Machu Picchu in Peru, visited a university in Nablus and presidential compound in Ramallah, attended courses in Spain and Ecuador, and traversed through multiple states in India. She is fluent in Spanish, has conversational abilities in French, and is learning Arabic.

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