

A PATHWAY TO REDUCING EMISSIONS FROM COAL POWER IN INDIA

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PREFACE

This report has been produced by the IEA Clean Coal Centre for the Coal Industry Advisory Board. It is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member organisations.

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ABSTRACT

India's energy demand will continue to grow over the next 20 years. India currently relies on coal for more than 70% of its power generation and thus its massive domestic reserves of coal will continue to be used. India's coal power sector contributes 1.1 GtCO₂/y. Coal combustion also contributes to poor air quality. Increased coal consumption can be separated from increasing emissions of CO₂ by the retirement or upgrading of subcritical units and the increased use of high efficiency, low emissions (HELE) plant. Compliance with the 2015 emission standards for NO_x, SO_x and PM is delayed, but they could be met by using technologies and practises widely used in other parts of the world. There is potential for CCUS in India. Practical and policy recommendations are made for how India can meet its growing energy demand with its domestic coal reserves, while reducing emissions of CO₂ and improving air quality.

ACRONYMS AND ABBREVIATIONS

AUSC	advanced ultrasupercritical
BEE	Bureau of Energy Efficiency
BHEL	Bharat Heavy Electricals Limited
Capex	capital expenditure
CBM	coal-bed methane
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CEA	Central Electricity Authority
CFA	coal fly ash
CfD	Contract for Difference
CERC	Central Electricity Regulatory Commission
CIA	carbon in ash
CIL	Coal India Ltd
CIMFR	Central Institute of Mining and Fuel Research
CSE	Centre for Science and Environment
DC	designated consumers
discoms	distribution companies
DOE	Department of Energy, USA
DST	Department of Science and Technology
EOR	enhanced oil recovery
ESP	electrostatic precipitator
EU	European Union
FEGT	furnace exit gas temperature
FGD	flue gas desulphurisation
FGR	flue gas recirculation
FYP	Five-Year Plan
GDP	gross domestic product
GoI	Government of India
GST	general sales tax
HELE	high efficiency, low emissions
HHV	higher heating value
HP	high pressure
ID	induced draught fan
IEACCC	IEA Clean Coal Centre
IEAGHG	IEA Greenhouse Gas R&D Programme
IOCL	Indian Oil Corporation Ltd
IPP	independent power producer
ISGS	interstate generating station
LCOE	levelised cost of electricity
LE	Life Extension
LHV	lower heating value

LNB	low NO _x burner
LP	low pressure
MNRE	Ministry of New and Renewable Energy
MoC	Ministry of Coal
MoP	Ministry of Power
MoU	Memorandum of Understanding
NAR	net as-received
NBFC	non-banking financial company
NDC	Nationally Determined Contribution
NEP	National Electricity Plan
NITI Aayog	National Institution for Transforming India Aayog
NO _x	nitrogen oxides
NSO	National Statistical Office
OGCI	Oil and gas Climate Initiative
OFA	overfire air
O&M	operation and maintenance
ONGC	Oil and Natural Gas Corporation
ONS	Office for National Statistics
Opex	operational expenditure
PAT	Perform Achieve and Trade
PLF	plant load factor
PM	particulate matter
PPA	power purchase agreement
PV	photovoltaic
R&D	research and development
R&M	Renovation and Modernisation
SC	supercritical
SCR	selective catalytic reduction
SEB	State Electricity Board
SNCR	selective non-catalytic reduction
SOFA	separated overfire air
SO _x	sulphur oxides
UMPP	Ultra Mega Power Project
USC	ultrasupercritical
VRE	variable renewable energy

UNITS

Bt	billion (10 ⁹) tonnes
CO	carbon monoxide
CO ₂	carbon dioxide
crore	10,000,000
dP	differential pressure
gCO ₂ /kWh	grammes of carbon dioxide per kilowatt hour
GtCO ₂ -e	gigatonnes of carbon dioxide equivalent
g/kW	grammes per kilowatt
GW	gigawatts (electric power generation capacity)
GWh	gigawatt hour
kcal/kg	kilocalories per kilogramme of coal
kJ/kg	kilojoules per kilogramme of coal
kWh	kilowatt-hours (electric energy generation)
lakh	100,000
mg/m ³	milligrammes per cubic metre
MJ/kg	megajoules per kilogramme
MtCO ₂ /y	million tonnes CO ₂ per year
MtCO ₂ /km ²	million tonnes of CO ₂ per square kilometre
Mtoe	million tonnes of oil equivalent
MW	megawatts (electric power generation capacity)
MWh	megawatt-hours (electric energy generation)
MWth	megawatts thermal energy generation
Rs	rupees
tCO ₂ /y	tonnes of CO ₂ per year
TWh	terawatt hour
wt%	weight per cent

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EXECUTIVE SUMMARY

This study, commissioned by the International Energy Agency's Coal Industry Advisory Board, offers a pathway to reduce emissions from India's coal fired power generation industry. It will help India deliver on its climate change commitments, improve air quality and enhance electricity reliability and access. In completing the study, the IEA Clean Coal Centre worked with key Indian stakeholders both in government and in the power sector.

INDIAN ECONOMY RELIES ON COAL

India is a vast country of 1.37 billion people which has undergone rapid economic growth over the last 20 years to become the world's fifth largest economy. This growth has been inextricably linked with a successful drive to increase the availability of electricity, with total power generation increasing by 40% over the last decade. Owing to the country's enormous coal reserves and limited oil and gas, coal fired power has remained dominant over this period, even slightly increasing its share of total generation to 72% (1135 TWh) in 2019.

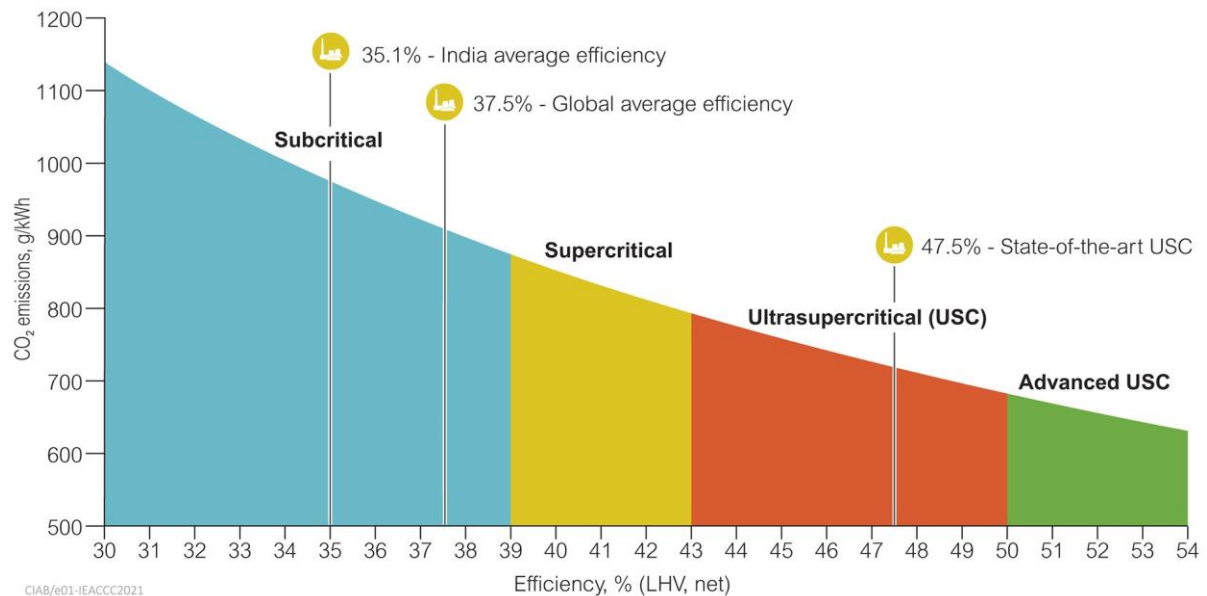
India is a success story in many respects. Rapid power plant deployment in recent years has meant that there is abundant generating capacity. Electricity access for all is mostly successful. Despite this remarkable rise, Indians still experience a per capita energy consumption of only around 10% that of high-income countries, and further growth in standards of living and associated energy demand is therefore urgently needed. While the Government of India has ambitious plans to meet much of the expected growth with wind and solar power capacity – up to 400 GW in 2030 – coal will continue to play a fundamental role in providing India with dispatchable power and energy security for the next 20 years and beyond.

REDUCING CARBON EMISSIONS WITH A FLEXIBLE, EFFICIENT FLEET

However, the Indian coal fleet emitted 1.1 GtCO₂ in 2019 and contributes to poor air quality in some regions, due to emissions of SO₂, nitrogen oxides (NO_x) and particulate matter, with associated impacts on health, ecology and economy. Coal quality varies substantially across India. A key challenge is the impact of burning high ash content (25–50%), indigenous coal on plant performance and emissions management.

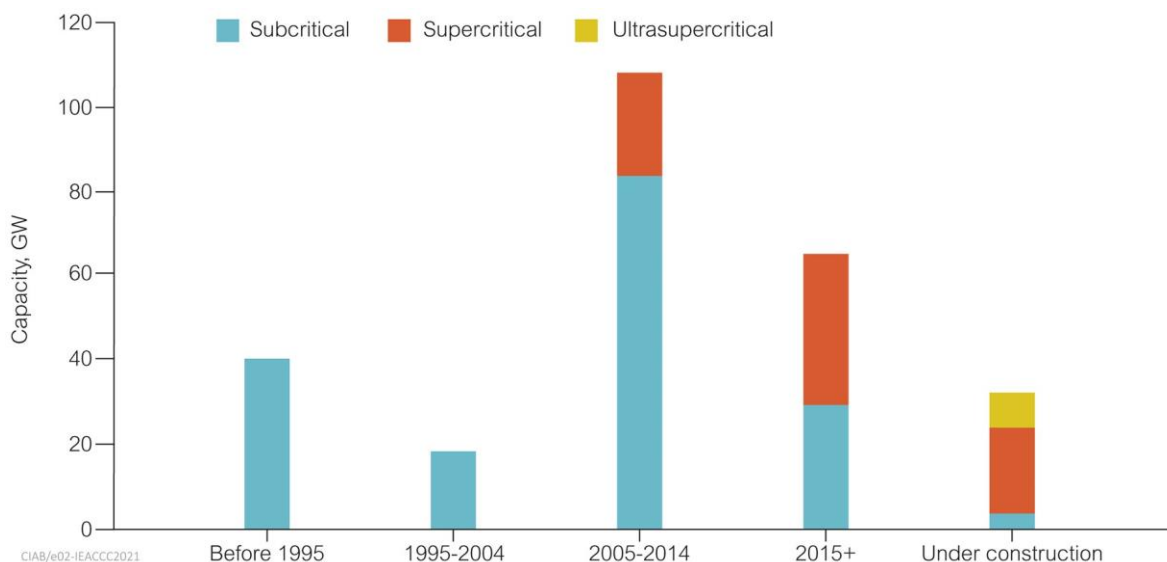
Increasing coal-fired power plant efficiency reduces emissions of CO₂ per MWh generated. In India the average unit efficiency is 35% compared to state-of-the-art efficiency of 47.5%. There is therefore significant potential to reduce CO₂ emissions from India's coal fleet through a combination of retiring or upgrading older units and building new efficient ones. There are various incentive schemes to promote upgrading of subcritical plants covering improved operation and maintenance (O&M) practices, instrumentation and control upgrades as well as more substantial turbine and boiler upgrades/retrofits. For example, the upgrading of some small units (<200 MWe) has resulted in

savings of over 100 kt/y coal and 165–190 kt/y of CO₂ emissions at each unit with a return on investment of less than 2 years.



CO₂ reductions achievable with increasing coal plant efficiency (IEACCC, 2020)

Coal-fired power plant capacity has more than quadrupled to over 205 GW (utility) in 20 years with a further 33 GW under construction. The first supercritical (SC) unit came online in 2010 and since then a further 52 GW of SC capacity has been added. The first ultrasupercritical (USC) plant was commissioned in 2019. By 2023 India is expected to have 250 GW of utility coal-fired generating capacity in operation, almost a third of which will be SC or USC. The hope is that this impressive performance of improving efficiency will be continued. However, new capacity additions have outpaced demand for electricity, so utilisation factors have fallen from approximately 70% in 2010 to 56% in 2019. Utilisation is likely to recover in the next few years.

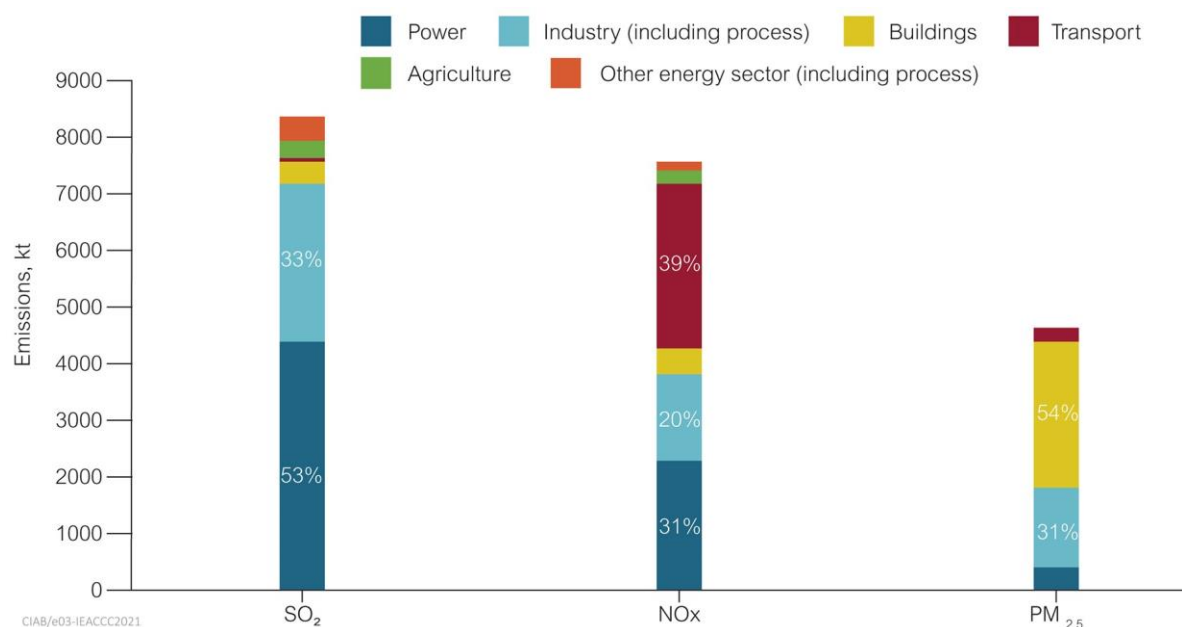


Composition of India's coal fleet by age and technology type (S&P Global, 2020)

The transition to higher efficiency technologies has already made good progress. However, further reductions in emissions could be achieved through changes to dispatch mechanisms and implementation of supporting policies such as:

- Continuing the transition towards economic-based merit-order dispatch to provide market incentives for more efficient, flexible units;
- Introducing efficiency standards to ensure all new units are supercritical as a minimum and ultrasupercritical from 2025;
- Easing the regulatory process for retirement of inefficient units and replacement with new ones;
- Encouraging greater use of digital tools to facilitate optimal operation, efficiency and flexibility; and
- Supporting technical capacity building and international knowledge sharing in the manufacture and operation of high-efficiency, flexible units.
- Based on experience in Europe and other regions, the ability to operate in a flexible manner will be key if coal power plants are to remain competitive in a market with a greater proportion of renewables. More emphasis will need to be placed on planning and readiness for likely changes in the market and operational environment.

EMISSIONS CONTROLS AND AIR QUALITY



India's SO_x, NO_x, and PM_{2.5} emissions by source, 2018 (IEA, 2019a)

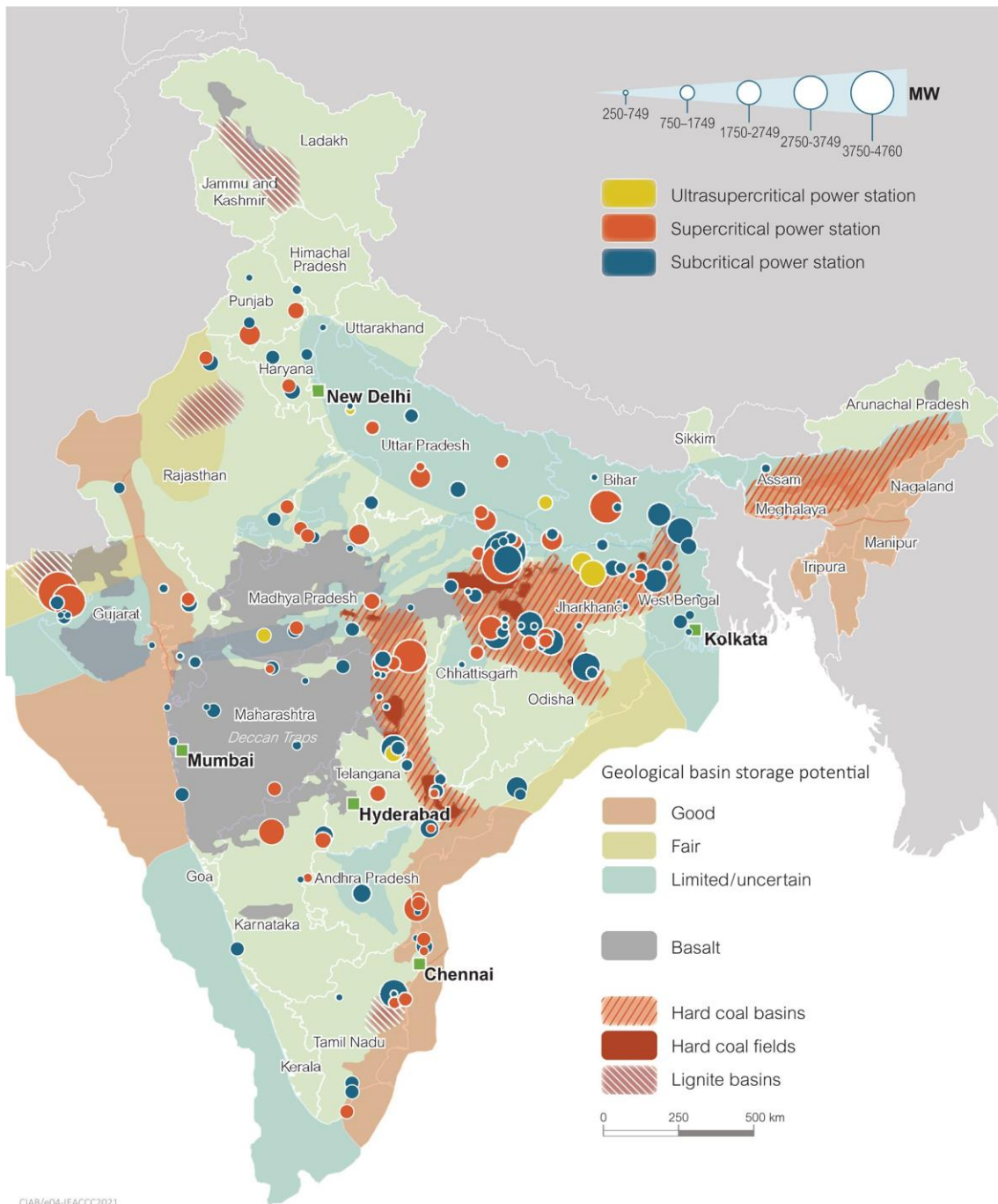
The introduction of more stringent emission standards 'norms' for coal power in 2015 was a significant step in mitigating air pollutants including SO₂, NO_x, and particulates. However, progress in meeting these standards through the widespread deployment of flue gas desulphurisation and NO_x control technologies has been slow, with the deadline extended to 2022 and some NO_x limits relaxed.

Significant NO_x reductions are achievable in most Indian coal plants simply through the effective combination of combustion optimisation and appropriate primary control measures. More costly secondary measures will be needed to achieve the stricter NO_x limits for newer plants, but these technologies can be successfully applied even to the relatively high-ash environments associated with firing Indian coals. Rather than seeking to delay implementation of the existing norms, the sector should work to anticipate the globally observed trend of progressively tightening standards. The recommendations include:

- Significant NO_x reduction (around 10%) and efficiency gains (up to 2 percentage points) can be achieved through optimisation and accurate monitoring of combustion parameters; In combination with optimised combustion, primary NO_x controls such as separated overfire air and low NO_x burners can be used effectively to reach 300 mg/m³;
- Selective catalytic reduction (SCR) can be adapted to the high-ash conditions associated with firing Indian coal, and should be further explored through full-scale trials, including ‘cold-side’ operation;
- Strong incentives to meet the emission standards, such as placing compliant plants higher in the merit order or imposing stronger penalties on those which do not take action;
- Emission standards should be met on a rolling average basis, helping to make lower emission standards (such as 300 mg/m³ for NO_x) practically achievable with primary measures alone;
- Reconsider the relaxation of the NO_x standard to 450 mg/m³ for plants built 2004 to 2017;
- Consider tightening the standard for plants commissioned before 2004 to 450 mg/m³, which should be easily achieved through primary controls; and
- The limit of 100 mg/m³ for plants built after January 2017 should be upheld, and achieved with a combination of advanced primary measures, appropriate operating and maintenance practice, and secondary controls.
- CO₂ capture utilisation and storage (CCUS)

As the only means of imposing deep cuts on fossil fuel CO₂ emissions, CCUS is experiencing a resurgence in global interest and should represent the ultimate goal for India’s coal fleet. Although India continues to actively support research in CO₂ capture and utilisation, energy shortages and perceptions of high costs and unpromising geological storage capacity have deterred political backing for large-scale deployment. However, recent rapid growth in coal power capacity and more ambitious climate targets present a more favourable environment for CCUS.

Recent studies estimate that the country has the potential to store at least 100 GtCO₂ (90 years of current coal emissions), even without considering emerging opportunities in basalt and deep coal seams. However, the true potential will only be clear once more targeted characterisation has been carried out. This study has mapped India’s coal plants against geological resources as a means of highlighting the most suitable storage locations and plant clusters for near-term development.



Locations of India's major coal plants with respect to CO₂ storage options

India can take a number of preliminary steps to drive early demonstration of CCUS and attain a state of readiness for greater deployment from 2030 onwards:

- A more detailed assessment of geological storage potential is urgently needed, including characterisation of promising saline aquifers in coal-producing regions;
- Priority dispatch for CCUS-equipped coal plant, together with tariff pass-through of additional coal costs, could act as an incentive for early projects;

- Enhanced oil recovery and CO₂ conversion technologies can also play a role in kickstarting first-mover projects, supported by incentives for domestic, low-carbon products;
- New coal plants in India should be ‘capture-ready’, including a storage assessment;
- The Methanol Economy is an opportunity to develop CCUS clusters associated with gasification clusters, incorporating production of high-value products and power;
- Government should coordinate an integrated, cross-sectoral technology demonstration strategy among relevant public sector undertakings; and
- CCUS should be explicitly included in India’s international climate commitments.

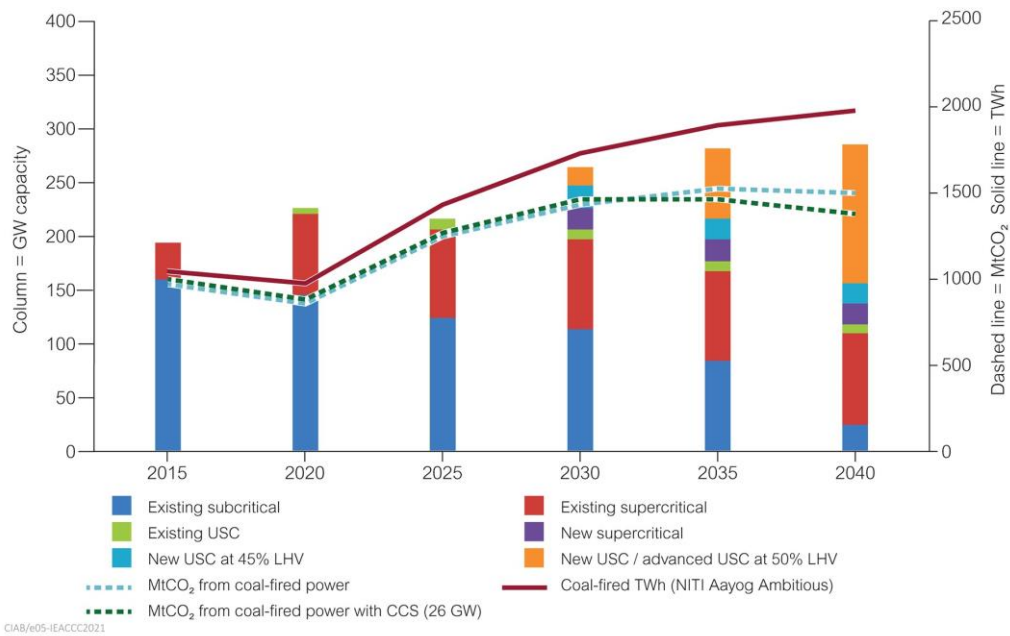
Initial financing of CCUS deployment will likely require international investment, international support, including through multi-lateral development banks, and policy incentives. Other incentives such as tax credits may be needed to further support CCUS deployment and wide-spread power system decarbonisation.

COAL POWER TO 2040

The future of coal-fired power generation is fundamentally determined by the overall rise in electricity demand and the penetration of non-coal power sources into the market. Thus, the share of the market taken by coal is likely to diminish but remain significant. In this study, analysis of coal power to 2040 in India is based on two pathways – one higher growth based on the NITI Aayog Draft Energy Policy (2017) and the other based on the lower rate of growth of the Stated Energy Policies (STEPS) scenario of the IEA (2020). Both scenarios show the CO₂ emissions that can be avoided if coal-fired units are retired after 25 years and replaced with HELE technologies. They also include the addition of CCS to 26 GW of coal-fired capacity.

Higher growth

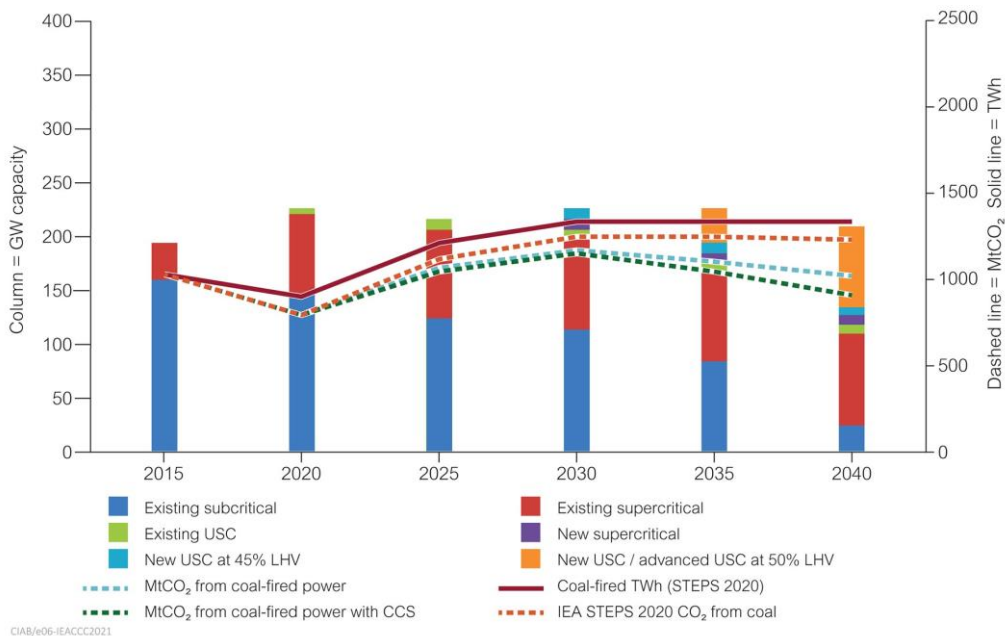
In the higher growth scenario, the replacement of 25 year old subcritical units with a range of HELE technologies decouples the rate of CO₂ emissions growth (blue line) from that of coal-fired capacity (red line). The addition of CCS from 2030 onwards to around 10% of the fleet reduces emissions further (green line). The results indicate that HELE plants with the addition of CCS on 26 GW of coal-fired capacity could avoid up to 4300 MtCO₂ between 2021 and 2040, equivalent to roughly 215 MtCO₂/y.



IEACCC projections based on NITI Aayog Ambitious Scenario

Lower growth

In the lower growth scenario, based on IEA 2020 STEPS power plants still retire after 25 years, and there is a greater decline in the need for coal-fired power. The subcritical fleet decreases to 23 GW by 2040, and the need for additional coal capacity is lower. The aggressive replacement of older plants with HELE ones, as recommended in the study, leads to a total decrease in CO₂ emissions from approximately 1104 MtCO₂/y in 2019 to 1023 Mt/y in 2040 with HELE plant only and 905 Mt/y in 2040 with CCS on 26 GW. More rapid deployment of HELE technologies in this scenario leads to a 27% lower emissions intensity for the sector in 2040, compared with the STEPS 2020.



The IEACCC HELE projections applied to the IEA 2020 STEPS outlook for power generation

KEY MESSAGES

This study offers a pathway to reduced emissions and improved air quality, while still using affordable and reliable coal power in a growing economy. Plant efficiency can be improved with some measures being inexpensive. Emissions standards can be met in many instances without costly measures and payback of only a few years. The resulting improvements will have health, environmental and economic benefits. Market reforms to finance to incentivise adoption of new, proven technologies will be required to achieve the desired improvements. Deploying HELE coal can help support government objectives, from improving air quality to operational flexibility in a market with increasing renewables penetration. Specific recommendations include:

- Increased emphasis on ultrasupercritical technology or better by 2040, with remaining subcritical units confined to minimal operating hours;
- Further focus on compliance with 2015 emissions standards using available technologies;
- CCUS – the groundwork such as storage assessment and regulatory development must be laid now if it is to remain an option;
- The power market should aim to value all aspects of energy provision, including availability, flexibility, and grid reliability and resilience;
- International support in the form of both investment and expertise should be further encouraged; and
- Nurture India's capacity as a global centre of engineering excellence in HELE and CCUS technologies.

There is a real risk that prevailing perceptions of coal as an outmoded energy source, combined with financial challenges, will stifle efforts to transition to cleaner forms of coal power and slow the promising progress made in transforming India's coal fleet. Recognising that coal power will remain fundamental to the country's pursuit of UN Sustainable Development Goals, including affordable and clean energy (SDG7), decent work and economic growth (SDG8), and industry, innovation, and infrastructure (SDG9), maximising the use of HELE coal technologies and CCUS must be seen as key to India's actions on both public health (SDG3) and climate change (SDG13).

1 INTRODUCTION

India has a fast-growing economy. Between 2010 and 2019, gross domestic product (GDP) grew 6-7%/y to reach US\$2.9 trillion (nominal). In 2018-19, India overtook France and the UK to become the fifth largest economy in the world in terms of nominal GDP. Rapid industrialisation and urbanisation have spurred economic growth; the ten fastest growing cities in the world in terms of GDP are in India (Wood, 2018; Whiting, 2019). Inevitably this pace of expansion means a rising demand for modern energy services, especially electricity.

Prior to the start of the COVID-19 pandemic in early 2020, economic forecasts were optimistic and predicted that expansion of the service and technology industries would drive economic growth to US\$8–10 trillion by 2030 (Gupta, 2019). Subsequently, GDP growth is estimated to have fallen to 2% (annualised) in 2020 but is expected to rebound to 7.4% in 2021 (NIE, 2020; IM, 2020).

However, India's vast population of 1.37 billion (18% of global total) means it is ranked 145th in the world in terms of GDP/capita at just US\$2172 per person (2019) (StatisticsTimes, 2020; IMF, 2020). Although the rate of population growth has declined to just over 1% in 2018, India could have a population of 1.6 billion by 2040 (UN, 2019a, World Bank, 2020a). GDP per capita is also increasing and could double by 2030 to reach 5000 US\$/y (13.7 US\$/d) (Gupta, 2019). However, 19% of the population is vulnerable to some form of poverty, and 9% experience it severely (UN, 2019b).

So, the population is still increasing, the economy is growing strongly, and there is much scope for energy demand to rise.

Power generation in India is coal dominated. During the last 30 years, there has been a major shift from traditional biomass to more modern energy supplies, notably electricity, which has increased the role of coal in the economy, from 30% of total primary energy supplies (TPES) in 1990 to 44% in 2017 (391 Mtoe). Around two thirds of the coal was used for utility power generation (IEA, 2020a).

Between 2009 and 2019, electricity consumption doubled from 612 TWh to 1158 TWh in India, making it the third largest electricity market in the world. Continuing growth in demand means electricity consumption could triple from 947 kWh per person in 2017 to around 3000 kWh per person by 2040 (NITI Aayog, 2017a; IEACCC based on IEA, 2019b; UN, 2019a). At these levels, Indian consumption will still be low compared with other BRIC countries (Brazil, Russia, India, China), the European Union, and the USA.

Between 2010 and 2018, access to electricity increased from 68% of the population to 95% (World Bank, 2020). The Saubhagya Scheme was introduced in 2017 to connect all the remaining 40 million households by December 2018 and thus complete the electrification of the nation (IDAM, 2019). Free connections in rural areas and to poor families in urban areas were offered. By 2019, 99.9% of the households in India (willing to be electrified), were connected to provide enough power for an LED

light and a power socket. However, even with access to the grid, it may not be available 24 hours a day, seven days a week. In 2018, the Council on Energy, Environment and Water (CEEW) found that the median number of hours of available electricity in households in the states of Bihar, Jharkhand, Madhya Pradesh, Odisha, Uttar Pradesh and West Bengal ranged from 15–18 hours per day (CEEW, 2018), although the situation continues to improve (CEA, 2019a).

India's success in expanding the reach and capacity of its electricity supply capabilities has been essential to alleviate poverty and extend economic prosperity. Between 2009-18 alone, power generation grew at 6.1%/y, adding 640 TWh to India's annual production; the equivalent to adding the entire output from the German power sector in 2018. Provisional estimates for 2018-19 show India's generation output reached 1547 TWh (see Figure 1).

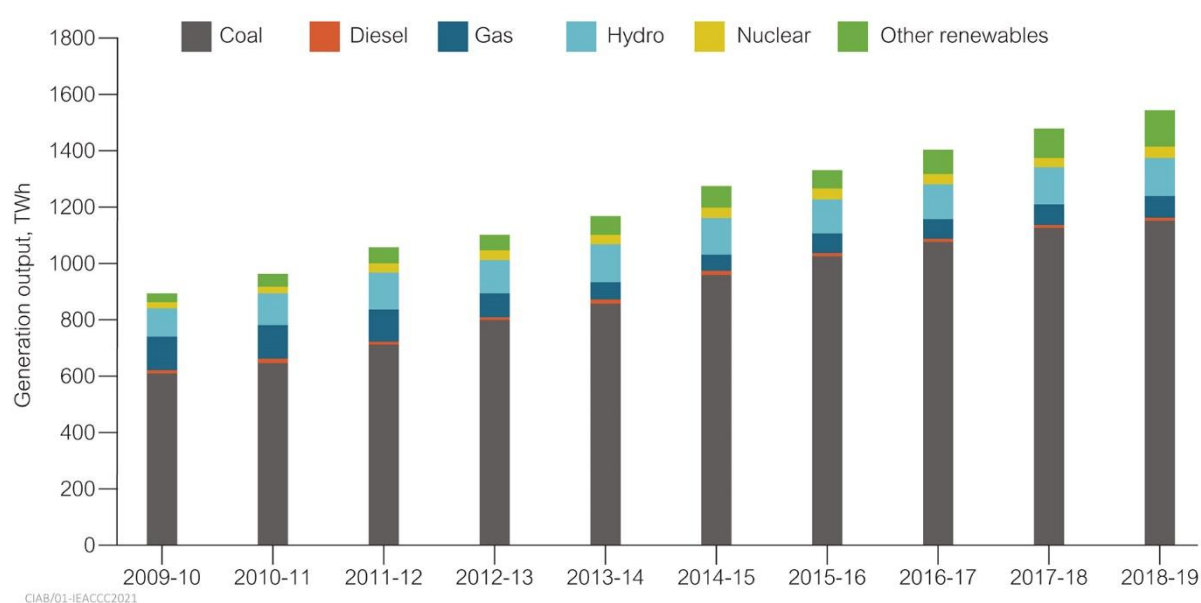


Figure 1 Electricity generation by fuel 2009-19, GWh (NSO, 2020)

Coal-fired power has increased its share of total generation from 68% to 75% between 2009-19 reaching 1163 TWh. However, non-hydro renewables, mainly solar and wind, have grown at an even faster rate, of 14.7%/y between 2009 and 2019 to reach 129 TWh output in 2018-19 (IEACCC based on NSO, 2020).

India's demand for power will continue to increase as the country becomes wealthier, electrification increases and the population grows. India has massive coal resources, so although the amount of renewable energy is increasing rapidly, power generation from coal continues to grow. Coal is also important to back up intermittent renewables, and India does not have substantial gas resources. India aims to limit imports of coal, although the indigenous coal generally has a high inherent ash content and low calorific value.

A major impact of continuing to use coal to meet energy demand is growing emissions of carbon dioxide (CO₂). It is estimated that India's emissions of CO₂ have doubled since 2005 and the

coal-dominated power sector is responsible for half of these emissions. India emits 6.4% of total global CO₂ emissions, making it the third largest emitter of CO₂ in the world (IEA, 2020a). Thus, actions taken in India to reduce emissions of CO₂, particularly from the power sector are especially important. As a participant in the Paris Agreement India has commitments to reduce emissions of greenhouse gases.

Using domestic coal, which has not been beneficiated, in relatively low efficiency subcritical power plants and those which do not have the optimum pollution control technologies fitted to all units contributes to the emissions of CO₂ and poor air quality familiar in India. Emissions of sulphur oxides (SO_x), nitrogen oxides (NO_x) and particulate matter (PM) are a particular concern.

Poor air quality in India has huge costs in terms of health impacts and increased mortality. It has been estimated that changing the emission trends of pollutants from thermal power plants could save an estimated 1.3 million deaths in India per year by 2050 (Health Effects Institute, 2018). One assessment has found that non-compliance with emission norms could result in around 300,000–320,000 premature deaths and 51 million hospital admission cases due to respiratory disorders between 2019 and 2030. The mortality and morbidity costs attributed to PM_{2.5} alone were estimated to be Rs 8,88,038 crores (US\$128 billion) and Rs 74,184 crores (US\$11 billion) respectively during 2015–30 (Srinivasan and others, 2018). According to Srinivasan and others (2018), compliance with the emission norms would result in benefits that outweigh the investment in installing pollution control technologies.

In India the population is still growing, as is the rate of urbanisation, electrification and energy demand. This means more power must be generated over the medium term, to 2040, at least. Although India has a rapidly expanding renewables sector, the country will continue to rely on coal as it is a relatively cheap, readily available domestic resource. The challenge is to meet the growing demand for electricity, while reducing the accompanying emissions of CO₂ and air pollutants particularly NO_x, SO_x, and PM. This report examines the issues in depth and produces a pathway to 2040 for India to achieve the coal-based economic development sought, while improving air quality and enabling international environmental goals to be met. The potential of increasing the efficiency of coal-fired power plants, adoption of pollution control methods and technologies, and carbon capture utilisation and storage for India is explored in depth.

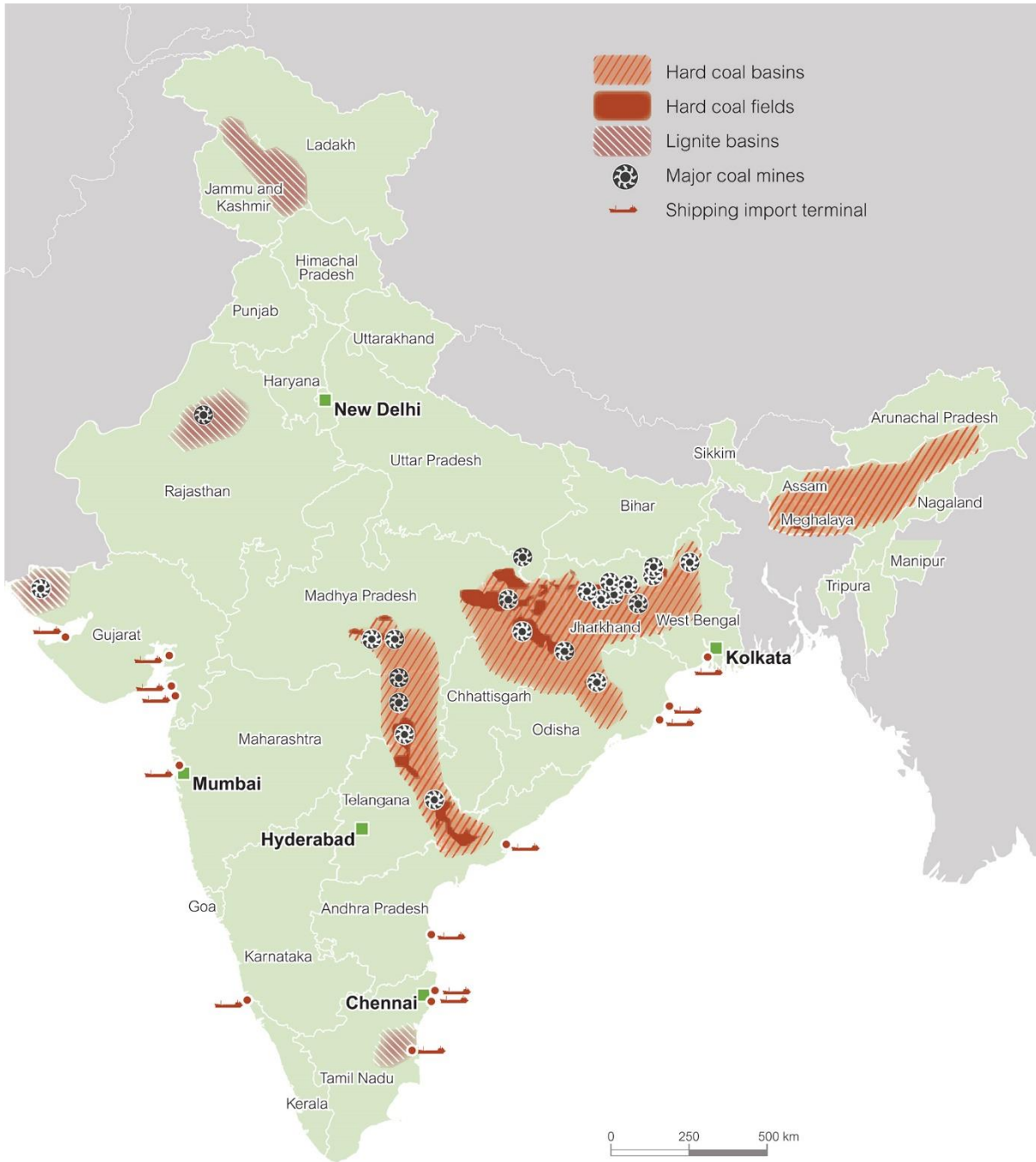
2 BACKGROUND AND KEY POLICY INITIATIVES

This chapter explains the importance of coal in India by describing the coal reserves and the scale of the coal power fleet. The current structure of the Indian power sector is outlined and the competitiveness of coal with other sources of power is analysed as a means of assessing coal's long-term prospects. Key energy and climate policies that influence the use of coal are reviewed.

2.1 COAL SUPPLIES

India is rich in coal, but supplies have been limited by the slow permitting process to open new mines, inadequate production, limited transport capacity, and excessive losses in the coal supply chain (Baruya, 2012). As of 2017, 70% of coal supplies come from coalfields located in the states of Jharkhand, Odisha, Chhattisgarh, West Bengal, Madhya Pradesh, Telangana, and Maharashtra (see Table 1). These regions account for 98% of total coal reserves, of which half is found in Jharkhand and Odisha (see Figure 2).

State	Proved	Indicated	Inferred	Total
Jharkhand	48.0	30.4	6.1	83.2
Odisha	39.7	33.5	7.7	80.8
Chhattisgarh	21.5	36.3	2.2	59.9
West Bengal	14.2	12.7	3.9	31.7
Madhya Pradesh	12.2	12.9	3.9	28.8
Telangana	10.6	8.6	2.7	21.8
Maharashtra	7.6	3.3	1.9	12.7
Andhra Pradesh	0.1	1.1	0.4	1.6
Bihar	0.3	1.5	<0.1	1.8
Uttar Pradesh	0.9	0.2	0	1.1
Meghalaya	0.1	<0.1	0.5	0.6
Assam	0.5	<0.1	0.0	0.5
Nagaland	<0.1	<0.1	0.4	0.5
Sikkim	0.0	0.1	<0.1	0.1
Arunachal Pradesh	<0.1	<0.1	<0.1	0.1
Total	155.6	140.5	30.4	326.5



CIAB/02-IEACCC2021

Figure 2 Map of coal reserves in India (adapted from Mills, 2016)

According to the BP Statistical Review of World Energy for 2019, India has 106 billion tonnes (Bt) of proved reserves, or 9% of the world total. Some 101 Bt comprise hard bituminous coal and anthracite and 5 Bt is lignite and subbituminous in rank (BP, 2020). Official government estimates for 2019 go further to suggest that India has 326 Bt of coal resources located at a maximum depth of 1200 m, of which 149 Bt is proved, a further 139 Bt is indicated and 31 Bt is inferred (MoC, 2020).

Coal India Ltd (CIL), a public sector coal mining and refining company, produces around 80% of the country's coal output. CIL and its subsidiaries accounted for 602Mt (provisional) of coal production during 2019-20. Singareni Collieries Company Limited is the main source of coal supplies in the south and produced 64 Mt in 2018-19 (GoI, 2020).

2.1.1 Coal quality

The quality of coal varies substantially across India compared with the narrower specification of internationally traded coal. Indian coals tend to have a lower energy content and higher ash, but benefit from relatively low sulphur and moisture contents. A typical Indian steam coal has a range of 25–50% mineral matter (ash) content, 5-9% inherent moisture, 18–32% volatile matter and 0.4–0.8% sulphur (Philalay and others, 2019; Sachdev, 2020).

Despite having moisture and sulphur levels comparable with thermal coal exports from Australia and Russia, the quality of Indian coal is affected by its mineral matter. The majority of it is inherent ash, meaning that the particles of mineral matter are embedded in the combustible part of the coal, making the ash harder to remove. The high ash content reduces the calorific value (CV) of the coal. Most of the coal currently produced in India falls in a range of 14.6–20.9 MJ/kg (3500–5000 kcal/kg) although some is outside this range. This is markedly lower than the average heat content of coals typically found in other large producing countries, such as Australia, China, the USA or Russia. They produce coals in the range 18.8–28.9 MJ/kg (4500-6900 kcal/kg). Most internationally traded coal is around 25 MJ/kg net as-received (NAR). (Baruya, 2018). Coal India Ltd (CIL) has 17 classifications of non-coking coal based on the calorific value. The lowest band is 17, which has a gross CV of 2200–2500kcal/kg(9.2–10.5 MJ/kg) while the highest is band 1 for coals of more than 7000 kcal/kg (29.3 MJ/kg).

The high ash content of coal can be reduced through washing processes, and this approach has been employed to various extents in India. However, even after washing the ash content can still be high at around 34% (see later). Nonetheless, unwashed coal contains a higher level of inert material which increases the cost of coal transportation (per tonne of combustible material) and creates challenges for the power station operator from increased wear on the pulverisers to problems with combustion stability, fouling, slagging, and emissions of fly ash. However, just 20% of Indian coal is beneficiated in preparation plants, and where coal is washed, the yield from raw coal can be low (Reid, 2017).

The whole of the coal chain is therefore involved – from the production, movement and handling of coal, much of which is incombustible, to the disposal of excess ash. In 2014, the Central Pollution Control Board (CPCB) notified the coal sector that power plants located 500 km or more from the pit-head of a coal mine could not use raw unwashed coal exceeding 34% ash. To aid compliance with the restriction, the Ministry of Environment simplified the approval process for building coal washeries. The aim of the strategy was to reduce the ash content of domestic coal, by placing the responsibility for washing coal on coal producing companies. On 21 May 2020, the constraint on

transporting domestic coal was relaxed, so now coal of any quality can be transported by rail over any distance. However, the prevailing plant emission standards set by the CPCB still stand, and the responsibility of reducing emissions is now almost entirely with power plant operators (Goswami, 2020). The benefits of coal washing on power plant operation are described in more detail in Section 3.2.2.

Washery capacity

India has approximately 130 Mt/y of washery capacity (2017), of which approximately 100 Mt/y is for steam (non-coking) coal (CSO, 2018). There are 34 washeries that serve these coal mines with capacities ranging from 0.33–6.5 Mt/y.

As of 2017, Coal India Ltd (CIL) operated 21 Mt/y of steam coal capacity at six washeries mostly located in Jharkhand. The throughput was just 4–6% of CIL's annual output of 570–600 Mt/y of steam coal (during 2017-19) (IEACCC estimate based on CIL, 2020). CIL planned to complete 18 new washeries by 2020, adding 67.5 Mt/y of steam coal washing plants, quadrupling its steam coal washing capabilities (Kumar, 2018).

The remainder of the country's coal washery plants were operated by 28 smaller private companies which have a combined capacity of 80 Mt/y, the largest of which is the 12 Mt/y plant operated by ACB in the Korba coalfields of SECL in Chhattisgarh. Most of these privately-owned washeries in India are located in Chhattisgarh (35.7 Mt/y), Maharashtra (32 Mt/y), and Odisha (9 Mt/y) (IEACCC estimates based on CSO, 2018).

2.1.2 Challenges to transporting domestic coal

The state railway company Indian Railways (IR) transports around 52% of the coal that is mined in the country, a share that is expected to rise significantly with the government's ambitious plans to increase coal production. However, IR has suffered from considerable under-investment in the past and coal supply logistics are often complex (Barnes, 2016). Railways face severe capacity constraints and freight transport costs by rail are much higher than most countries as freight tariffs in India have been kept high to subsidise passenger travel.

India's plans for an expanded power sector depend critically on rail links between ports, mines and their customers. In 2015 a White Paper was published setting out a programme of investment and restructuring to improve the situation which involved important stakeholders such as the Ministry of Coal (MoC).

In 2020, CIL announced a Rs 500 billion (US\$6.6 billion) plan to expand its coal transportation infrastructure to support its production target of 1 Bt/y by 2024. Much of the problem lies with bottlenecks between the mines and inland transport which will be eased by mechanising the connectivity between mines and rail services by using conveyor systems.

The high ash content of domestic coal impedes efficient transportation as it means that large quantities of inert material are transported together with the combustible fuel. CIL's targets for future production will increase the demand on rail facilities some of which are already reaching saturation. Rail infrastructure is capital intensive and can be effectively managed by minimising the extra load of carrying excess inert material by beneficiating coal to improve its quality and consistency. The benefits of washing and preparing coal to a higher standard product enhances the loading capacity of rail wagons in terms of the energy content of the cargo, it reduces the premature wear on handling equipment such as chutes and hoppers, releases useful carrying capacity on the existing network, and greatly reduces transportation costs – particularly over longer distances. Reducing ash from 41% to 34% results in rail cost savings of 15%. By transporting less inert material, the fuel consumed per GJ of energy conveyed reduces, thus also reducing the CO₂ emissions from transportation. These transport savings however need to be offset by the added cost of coal washing and preparation.

2.1.3 Coal imports

Although imported thermal coal has a lower ash content than domestic production, the GoI wishes to replace imported coal with domestic production. Broadly, this policy is aimed at increasing self-sufficiency in coal supplies while improving the country's balance of payments by reducing imports.

In 2019, the GoI announced ambitions to expand domestic production from 730 Mt in 2019 to 1149 Mt by 2023. New mining capacity, expanding existing capacity, and the commissioning of new coal washeries (chiefly for coking coal) were the key components of the plan to boost India's domestic supply capabilities. The Ministry of Power (MoP) has also suggested the possibility of supplying domestic coal to the export market (PIB, 2019).

Despite this, Indian steam coal imports rose in FY2019-20 to 197 Mt (*see* Table 2). However, the economic events of 2020 caused a dramatic drop in both demand and production leading to a rise in coal stocks at power stations and import ports by April 2020. According to SSY (2020), imports of thermal coal in the calendar year 2020 were estimated to be 156 Mt.

Coal	2014-14	2015-16	2016-17	2017-18	2018-19* Provisional	2019-20* Provisional
Coking coal	43.72	44.56	41.64	47.00	51.84	51.88
Non-coking coal	174.07	159.39	149.31	161.27	183.40	196.72
Total coal imports	217.78	203.95	190.95	208.27	235.24	248.55
Coke	3.29	3.07	4.35	4.58	4.93	2.91
* Last updated on 13 August 2020						

As part of the programme of domestic coal industry expansion, CIL aims to replace 100 Mt of imported steam coal in 2020-21, thus potentially displacing half to two thirds of thermal coal imports (Argus, 2020; IEACCC estimates). Part of the substitution plan was intended to market high-grade Indian coal at an attractive reserve price to industrial users first as a test via an e-auction. The offers for coal traded on this platform initially will cover 15–20 Mt before offering coal at larger tonnages to the power sector in the future (MCR, 2020; Chaturvedi, 2020).

However, substituting imported coal with Indian products is not straightforward. Plants designed for imported coal amount to around 55 Mt/y of demand and may require adaptation to fire effectively the higher ash and lower CV coals commonly supplied by CIL.

Domestic coal is generally cheaper than imported coal, with the exception of coastal plants around India which face higher transport costs from the mines located inland (Modi, 2020). Switching to, or blending with a higher proportion of, cheaper domestic coals must be balanced with the economics of handling and burning higher ash coals. In particular, the higher inherent ash content and the lower CV mean more coal is needed per unit of power generated. So, while the cost per tonne is cheaper, the cost per MJ may reduce the competitiveness of domestic coal especially for unwashed coal products. The sulphur, moisture and ash content should also be considered on a per MJ basis. Thus, efforts to increase domestic production may not completely dissuade importers of coal to continue to source supplies from the seaborne market for now; however, the overall growth prospects for imports may be somewhat subdued, as shown in the sharp downturn in in imports in 2020 (see Figure 3).

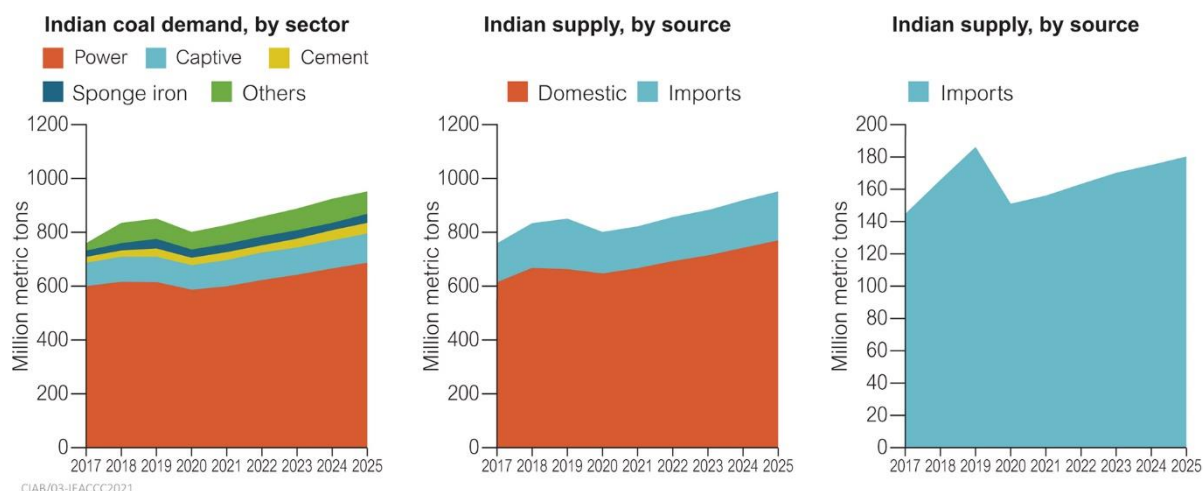


Figure 3 Indian coal demand and supply projection to 2025 (Stevenson and others, 2020)

2.2 STRUCTURE OF THE POWER SECTOR

India is a federal parliamentary republic made up of 28 states and nine union territories. Both central and state governments play an important role in the power sector, which is a shared responsibility under the Indian constitution. India's energy sector has a complex structure in which five ministries co-operate and co-ordinate to meet the country's need for power and the central government interacts with the regional state governments to enact and implement policy initiatives. At federal level, five ministries including the Ministry of Power (MoP), the Ministry of Petroleum and Natural Gas (MoPNG), the Ministry of New and Renewable Energy (MNRE), the Ministry of Coal (MoC) and the Department of Atomic Energy (DAE) have responsibilities for separate components of the energy sector (IEA, 2020a). The MoP governs India's electricity sector and hosts the Bureau of Energy Efficiency (BEE). The Central Electricity Authority (CEA) is the main advisor to the MoP and is responsible for national power planning, policy making and monitoring progress.

India's electricity sector can be divided into regulators, generation, transmission and distribution as illustrated in Figure 4.

	Central Government	State Government	Private sector
Policy	Ministry of Power Central Electricity Authority Bureau of Energy Efficiency	State Government State Government Energy Agencies	
Regulation	Central Electricity Regulatory Commission	State Electricity Regulatory Commissions	
Generation	Ministry of Power National Thermal Power Corporation National Hydroelectric Power Corporation North Eastern Electric Power Corporation Joint Ventures Ministry of New and Renewable Energy Renewables Department of Atomic Energy Nuclear Power Corporation of India Ltd	State Power Generation Companies State Power Generation and Distribution Companies	Independent Power Producers Tata Power Reliance Power Adani Power Captive Power Producers Steel industry Fertiliser industry Petrochemical industry

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Figure 4 India's electricity sector (IEA, 2019a)

Following India's independence in 1947, state-owned, vertically integrated State Electricity Boards (SEBs) were established for the provision of electricity; this structure has steadily transitioned to more competitive, unbundled markets through a series of liberalising reforms. Early electricity market reforms in the 1990s aimed to encourage private sector and foreign investment in power generation, but had limited impact. By the late 1990s, a few states had separated their generation, transmission, and distribution businesses and set up independent state regulators, while the Central Electricity Regulatory Commission was established in 1998 to oversee interstate transactions. The framework for India's current market structure was established by the Electricity Act of 2003, which delicensed thermal power generation (allowing any entity to develop a new project, subject to permitting), required the unbundling of generation from transmission and distribution, and established a schedule for states to open up generation and supply to competition (Sen and Jamasb, 2013).

Power generation can be provided by centrally owned power plants (primarily NTPC, Damodar Valley Corporation, and NLC India), state generating utilities, or independent power producers (IPPs) (Table 3). The further opening up of the market in 2003 led to rapid growth in private-sector involvement in coal generation, which now accounts for around 37% of total capacity (CEA, 2020a). Transmission and distribution are conducted at the state level by utilities known as distribution companies or 'discoms', with an overlaid Inter State Transmission System (ISTS) owned mostly by Power Grid Corporation of India. In 2008, two power exchanges were established for day-ahead trading of electricity: the Indian Energy Exchange and the Power Exchange India (PowerLine, 2018).

Plant owner	Coal fleet, GW	Type of owner
NTPC Ltd	54.9	Government owned utility, Central
Adani Power Ltd	12.4	Private power – IPP
Maharashtra State Power Generation Co	10.4	Government owned utility, State
Uttar Pradesh Rajya Vidyut	9.4	Government owned utility, State
Damodar Valley Corp (DVC)	8.0	Government owned utility, Central
Tamil Nadu Generation and Distribution Corp Ltd	7.8	Government owned utility, State
Rajasthan RV Utpadan Nigam	7.6	Government owned utility, State
NLC India Ltd	6.1	Government owned mining and power, Central
Telangana State Power Generation Corp	5.9	Government owned utility, State
Reliance Power Ltd	5.8	Private power – IPP

In the current electricity market, discoms procure the majority of power (over 80%) through long-term contracts with generators, while meeting daily variations in demand through short-term bilateral transactions and purchases from the power exchanges (Figure 5). While the bulk of contracted electricity is usually from state generators, there are also inter-state generating stations (ISGS) whose output is shared between discoms – these are mostly centrally owned, but can include IPPs (Ahmad and Alam, 2019). From the early 1990s, contracts were based on a regulated ‘cost-plus’ tariff aimed at providing a guaranteed rate of return for generators, set by the Central Electricity Regulatory Commission (CERC) for centrally owned plants or State Electricity Regulatory Commissions (SERCs) for state generators. These comprise a fixed charge based on power plant fixed costs and a return on investment, and an energy charge based on fuel costs and benchmark efficiencies. However, since the National Tariff Policy of 2005, there has been a shift towards competitive bidding for long-term power purchase agreements (PPAs), particularly for IPPs. This is usually based on bids for a single-part, levelised tariff, and has tended to result in lower tariffs than those obtained through the regulated system. A new policy in 2016 has made competitive bidding for tariffs mandatory for most power projects (Aureus Law Partners, 2020).

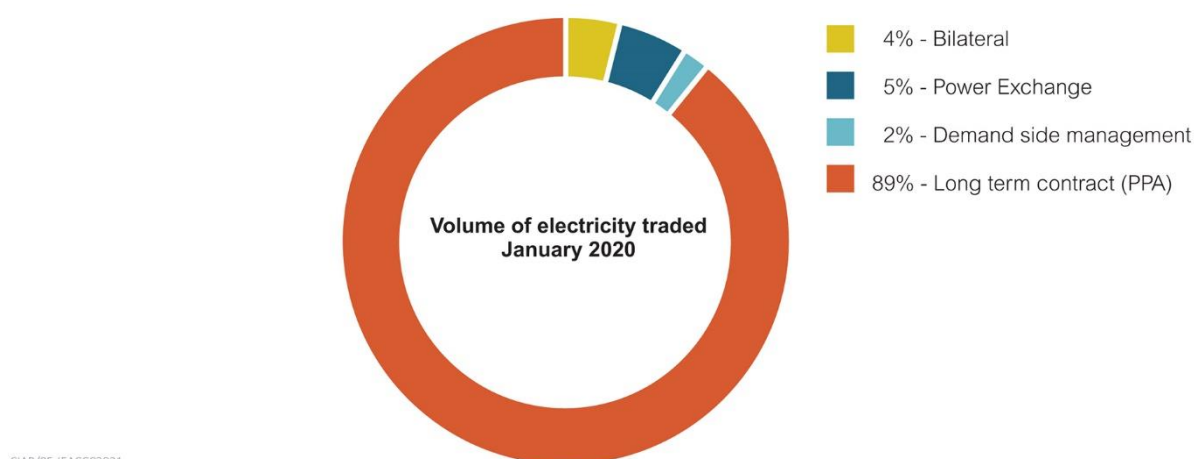


Figure 5 Breakdown of electricity trades by volume in January 2020 (Sinha, 2020a)

In principle, discoms dispatch their contracted generators according to the lowest energy charge rating, establishing a form of regional merit order dispatch in the day-ahead schedule. Since 2002, an availability-based tariff has also existed to encourage plants to shift from their schedule in such a way as to counter frequency excursions in the grid. A real-time market (in 15-minute time blocks) operates for these ‘deviations’ in generation from the day-ahead schedule; more recently, the rates charged under this ‘deviation settlement mechanism’ have been linked to prices in the day-ahead energy market, rather than an administratively determined value (Patel, 2019). A significant step towards more competitive, nationwide dispatch was taken in 2019, when ‘security-constrained economic dispatch’ (SCED) was applied to ISGS, allowing the lowest cost plants (regardless of discom contracts) to be prioritised in a day-ahead schedule of 15-minute blocks.

In general, a more flexible, wider-area market with more time-dependent price signals is seen as an essential target in the context of India’s ambitious targets for variable renewable energy (VRE) deployment. Ultimately, the goal is to establish a centralised market for energy and ancillary services with day-ahead scheduling, real-time dispatch in five-minute time blocks, and locational marginal pricing (Singh, 2019, Patel, 2019). Under this model, existing bilateral contracts used by discoms could be converted into financial contracts which serve to hedge against price volatility in the real-time market, similar to the system in the US restructured markets (Patel, 2019). This national electricity market platform should enable discoms to identify and procure cheaper generation from outside their established portfolio (Pujari and others, 2019, Singh, 2019). In June 2020, a significant step was taken as the Indian Energy Exchange launched a real-time market, allowing trading in half-hourly auctions up to an hour before delivery (Economic Times, 2020b).

2.2.1 Financial challenges

India’s State Electricity Boards have historically endured financial struggles, burdening state governments with large annual losses, due to large transmission and distribution losses (from both inefficient infrastructure and power theft), inadequate metering, non-payment of bills, and policies

which fixed low tariffs for certain consumers – particularly the agricultural sector. These challenges have been inherited by the successor discoms, leaving them unable to pay generating companies and building up collective debts of Rs 1.29 trillion (US\$17.5 billion) to generators by July 2020 (Bloomberg Quint, 2020). Central government sought to address the growing problem in 2015 with a bailout and restructuring programme known as the UDAY scheme, which required discoms to reduce losses primarily through improved metering (IEA, 2020A). However, progress appears limited, and reduced demand associated with COVID-19 has greatly exacerbated the problem. In May 2020 central government acted to waive overdue payment fees for the sector and provided a loan from state banks of Rs 900 million (US\$12 million) in May 2020 – also based on the condition of reducing losses (Chatterjee, 2020a).

In order to support reduced politically favourable tariffs for agricultural and domestic consumers, many states have a well-established ‘cross-subsidy’ system in which higher tariffs are charged to industrial consumers (Sen and Jamasb, 2013). As a result of higher tariffs and poor grid reliability, industrial consumers have tended to favour setting up captive plants, which further reduces revenue for the sector (IEA, 2020A).

The weak financial position of the discoms and their huge outstanding debts to the generating sector has a direct impact on the finances of generating companies and their ability to invest. In addition, generating companies with high proportions of thermal power generation are under further stress from the low plant operating hours, as a result of overcapacity and the growing role of low-cost renewable generation in the sector (*see* Section 2.3.2). Power sector stakeholders also point to the phase-out of long-term PPAs, higher cost of capital, and lack of financing as barriers to investment in new generation capacity (Kendhe, 2020).

2.3 THE COAL FLEET

2.3.1 Technology breakdown

India’s period of electricity market restructuring has helped drive an ambitious power station building programme over the last two decades. The coal-fired fleet has more than quadrupled since 2000 from 50 GW to more than 230 GW in 2020, and a further 33 GW is currently under construction (S&P Global, 2020). Of the currently operating capacity, around 205 GW is associated with utility power generation, with the remainder contributed by captive industrial plants – these units can also sell power to the grid if the economics are favourable.

In 2010, the country’s first supercritical (SC unit) (660 MW) came online at the Mundra Adani plant operated by Adani Power Ltd. In the following nine years, Indian power producers added a further 52 GW of SC capacity, around half of which was installed by IPPs such as Adani Power and TATA Power Ltd. The first ultrasupercritical (USC) plant was a 660 MW unit commissioned in 2019 at Khargone 1 by the NTPC. A further 8.6 GW of USC plant is under construction and planned to come

online between 2020 and 2023 (Figure 6). By 2023, India is expected to have 250 GW of utility coal-fired generating capacity in operation, almost a third of which will be SC or USC.

Figure 6 shows the current age and technology profile of India's operating coal fleet, and units under construction. Owing to rapid expansion this century, the fleet is relatively young, with only 17% of capacity over 25 years old, and 42% either commissioned in the last five years or under construction. However, the predominance of subcritical technology throughout most of the rapid growth period means that the fleet remains largely subcritical, at 74% of operating capacity.

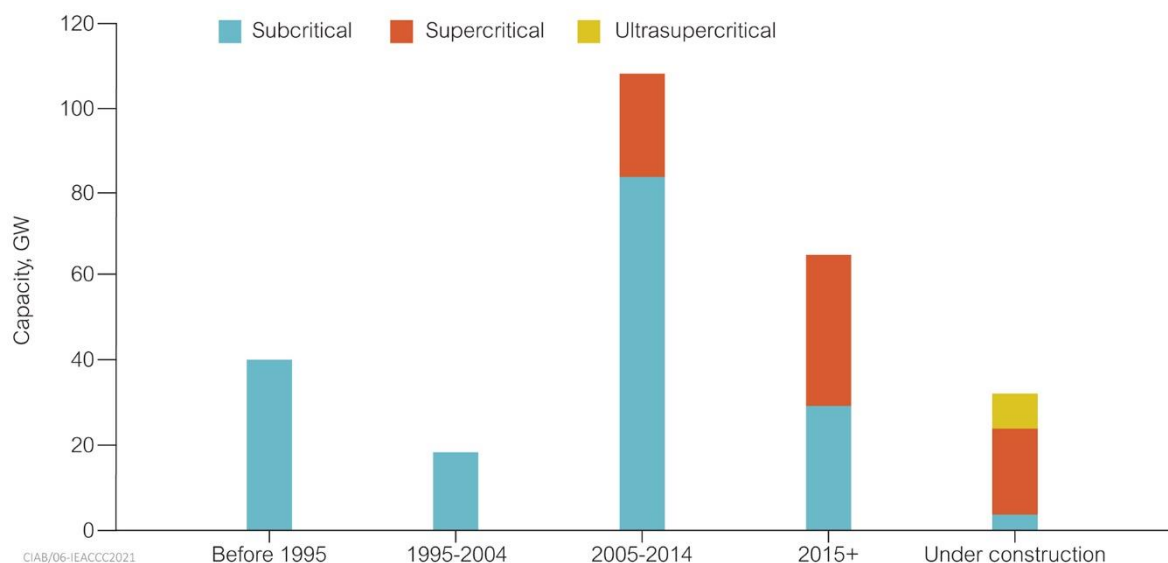
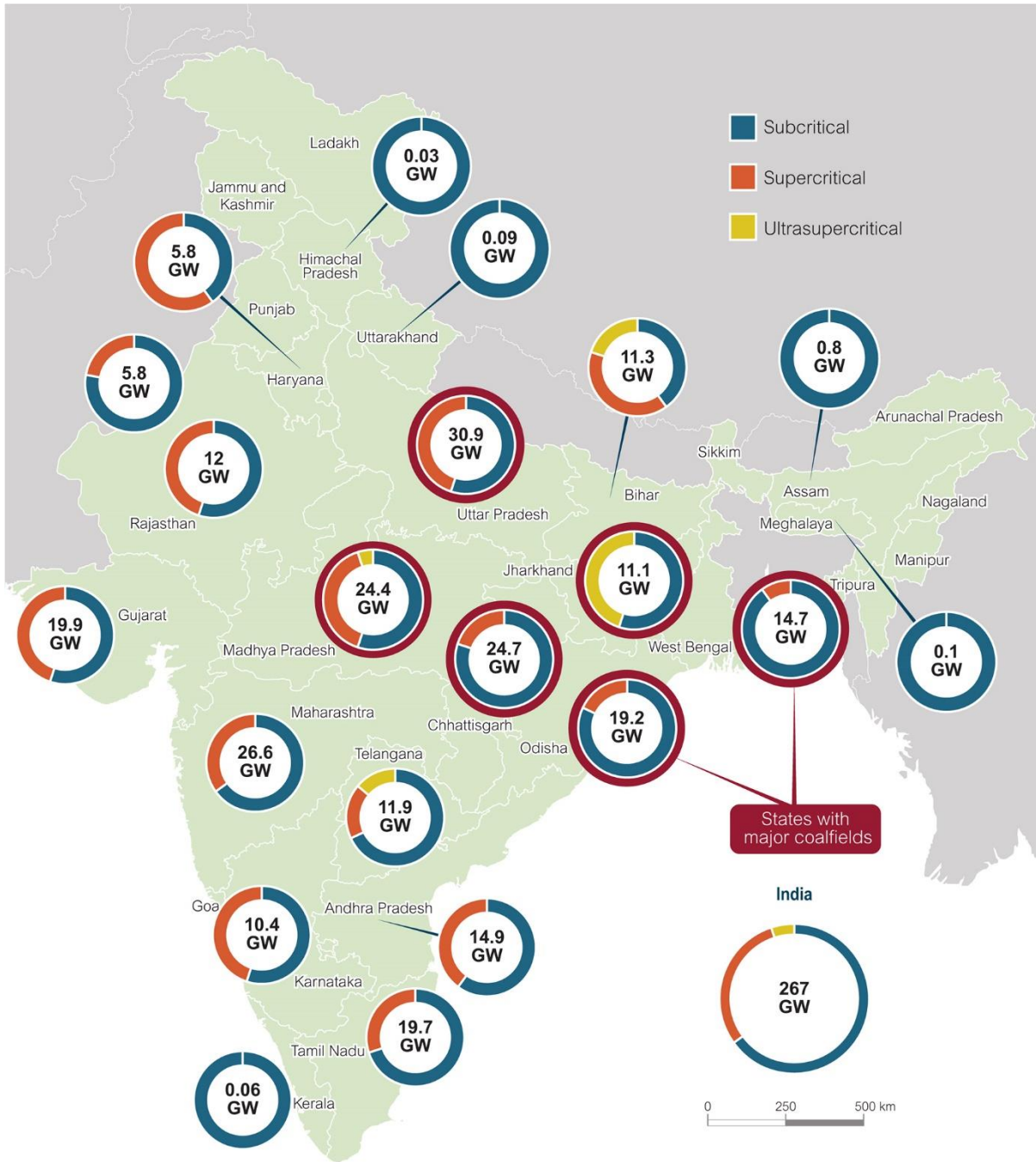


Figure 6 Composition of India's coal fleet by age and technology type (S&P Global, 2020)

Figure 7 illustrates the regional distribution of the coal fleet, including plants that are both operating and under construction in each state; all but five small states have now built SC or USC technologies. Around 125 GW, or 47%, of India's coal capacity is clustered within the major coalfields in Chhattisgarh, Jharkhand, Madhya Pradesh, Odisha, Uttar Pradesh, and West Bengal (see Figure 7) and are therefore important targets for emission reduction strategies. But significant coal capacity that can be improved is found across the country.



CIAB/07-IEACCC2021

Figure 7 Breakdown of the coal fleet by state and technology type, including existing units and units under construction for utility and non-utility operators* (IEACCC, 2020)

*Totals may not equal the sum of states due to rounding

2.3.2 Utilisation trends

Between 2009-10 and 2018-19, coal-fired power capacity in India increased by 10%/y, while output from the stations only increased by 7%/y (see Figure 8). As new capacity additions outpaced the demand for electricity, the utilisation of the fleet has gradually fallen from approximately 70% in 2010

to 56% in 2019 (CEA, 2019a). In the past, inadequate coal supplies were responsible for much of the loss of available capacity; poor supplies accounted for 16% of coal power losses in 2012. In 2017-18 fuel supply shortages reached a critical point at some locations; 10 power plants temporarily had zero stocks and 55 plants had less than 7 days' worth (Jai, 2018a). However, supplies vary from year-to-year and a shortage of coal stocks at power stations is currently less common. In the first half of 2020 there was a significant surplus due to the slowdown in electricity demand boosting stocks to 25 days and peaking in May at 31 days (IHS, 2020).

The fuel stock surplus is concurrent with the sudden drop in coal plant utilisation. Based on preliminary data for 2020, the average utilisation of coal plants could fall further to 40–50% due to the nationwide lockdown in the first half of the year. The pressure on coal-fired power operation is also due to the growing role for must-run forms of electricity such as renewables and nuclear which tend to take priority in the despatch order.

However, the decline in the utilisation of the coal-fired fleet has not diminished the role of coal in the electricity market. From 2009 to 2019, the percentage share of coal-fired power increased from less than 70% to 75%. There was also a rapid rise in output from renewables and their share accounted for 16% (8% hydro; 8% solar and wind) in 2019. In the same period, non-hydro renewable power experienced a rapid rise in capacity (19.5%) and generation (15%). However, like coal power plants, capacity additions have outpaced actual operating hours and thus average utilisation of non-hydro renewables has declined from around 27% to 18.5% (*see* Figure 8) (IEACCC estimates based on NSO, 2020). Natural gas-fired plants have suffered a particularly severe drop in utilisation from 62% in 2009 to 26% due to large shortfalls in domestic gas supplies to power plants (CEA, 2019a).

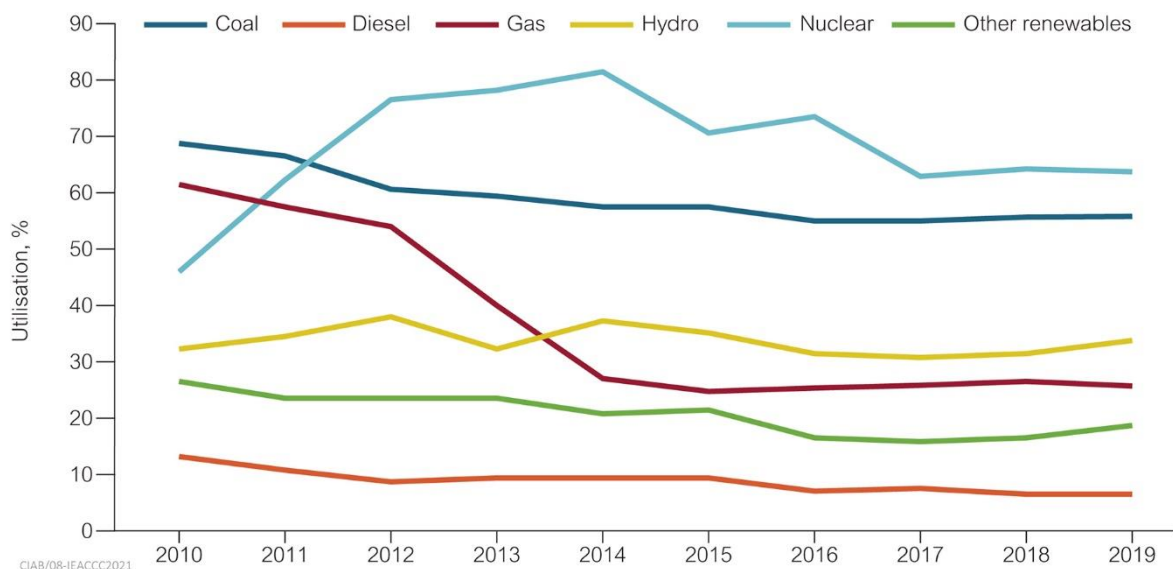


Figure 8 Power station utilisation by fuel, % (IEACCC based on ONS, 2020)

2.4 COMPETITIVENESS OF COAL-FIRED POWER

The cost of renewable power continues to fall due to improving technology, economies of scale, increasingly competitive supply chains, growing developer experience and prioritisation by government. In 2019, the global average cost of electricity from utility-scale solar photovoltaics (PV) fell 13% to 6.8 cents/kWh; concentrated solar power (CSP) fell 1% to 18.2 cents/kWh (IRENA, 2019). However, the average conceals the spread of costs which is wide for solar PV, ranging from less than 5 cents/kWh to more than 40 cents/kWh. India has experienced dramatic reductions in the installation costs of solar PV, falling to 793 US\$/kW, compared with the global average of 1210 US\$/kW and China, currently the world's largest solar PV market at 879 US\$/kW. In terms of new projects, half of the world's ten largest solar plants are being built in India. During daylight hours, some of the lowest cost solar PV tariffs in India reached 3.4 cents/kWh (2.36 Rs/kWh) in 2020 (Dvorak, 2020).

The comparison between the cost of solar and coal is not straightforward. Figure 9 illustrates the effect of the price of coal on the fully levelised cost of electricity (LCOE) based on the building and operating of a new USC plant in India in 2020 (dotted line). The LCOE of new USC is estimated to be 60 US\$/MWh, making it competitive with the average LCOE of onshore wind, but approximately 2 US\$/MWh more than solar (IHS, 2020). When comparing the short run marginal cost (SRMC) coal is extremely competitive at 3 US\$/MWh. SRMC is the cost of generating an extra MWh of electricity, typically using just the cost of fuel and operation and maintenance (O&M). Neither LCOE nor SRMC cost comparisons factor in the total system costs of delivering electricity from predominantly VRE sources. These costs include the new transmission and distribution systems required to link dispersed renewables to the grid, the energy storage capacity required to maintain reliable supplies and the additional generation capacity required to act as back up for when the variable renewables are not available. Moreover, thermal coal power plants provide energy security services that VRE do not. These include maintaining system frequency and system voltage and restarting the system after black-out. The additional capacity, by definition, has a low utilisation rate, and so, on its own is not economic, although essential to the reliable delivery of predominantly renewable electricity. The cost of battery storage, pumped hydro, and spinning reserve as a form of backup power can range between 10–398 cent/kWh in OECD countries depending on the scale and location of the storage system (Lazard, 2019).

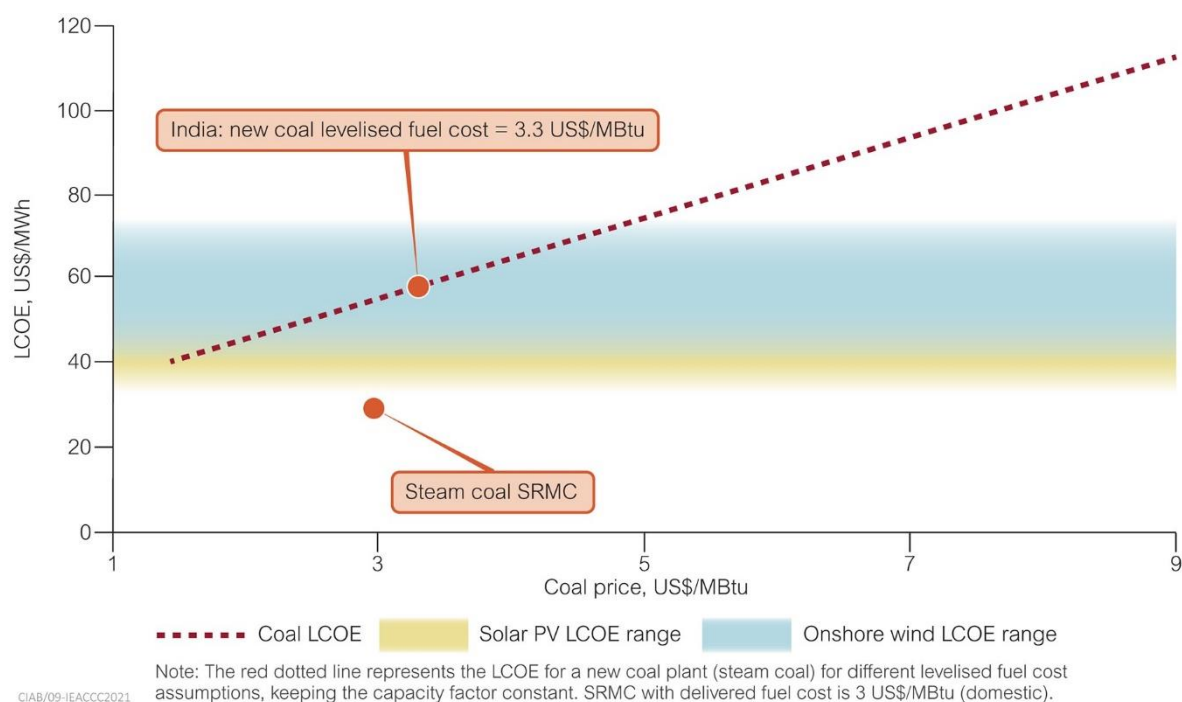


Figure 9 Cost of generating electricity by source, US\$/MWh (IHS, 2020)

2.5 ENERGY AND CLIMATE POLICY

2.5.1 Power generation policies

The main objectives of India's energy policy are to achieve universal access to energy and energy security (Zhu, 2020a). The GoI seeks to power further economic growth to raise living standards. Thus the power sector is at the heart of achieving these goals. From 1947-2017 the Indian economic, social and energy policies were structured around Five-Year Plans (FYP) developed by the Planning Commission. As stipulated by the 2003 Electricity Act, the CEA also formulates related five-year National Electricity Plans (NEPs) which project demand and consumption, energy production, and set framework and targets for power generation for the planned five-year period. The 2012 NEP, which covered the 12th FYP period 2012-17, played a key role in driving the modernisation of India's coal fleet described in Section 2.3.1. It outlined some major initiatives for greenhouse gas mitigation strategies and efficiency improvement measures of coal-based power plants:

- increasing power generating unit size with higher steam parameters;
- adopting clean coal technologies such as SC, USC and integrated gasification combined cycle (IGCC) technologies;
- the Renovation & Modernisation (R&M) and Life Extension (LE) programmes;
- energy efficiency improvement;
- retirement of old inefficient units; and
- coal quality improvement.

The 12th FYP aimed to set India on a pathway to reduce emissions intensity (kgCO₂ per unit GDP) by 20–25% below 2005 levels by 2020. As part of this plan, it was expected that 88 GW of conventional power capacity would be commissioned with 50% of the target to be achieved through SC units, along with 55 GW of renewables capacity. It also mandated the need to invest in research and development (R&D) of advanced USC (AUSC) technologies through government sponsored research (see Section 3.5.1). By the end of the 12th FYP period, India had achieved and exceeded the target for the first time with a total addition of >99.2 GW conventional power capacity. Of this total, 85.5% (84.9 GW) was coal-fired power plants, 42% of which are SC power units with unit size ≥660 MW. This achievement is about 112% of the target (CEA, 2019a). The 2012 NEP also identified about 4 GW of thermal power units about to be retired, including the remaining coal and lignite units of <100 MW and some coal units of 110 MW size. By 2018, more than 3.5 GW of coal power plants had been retired (CEA, 2012, 2018a,b).

In 2015, the MNRE set an ambitious new target to deploy 175 GW of renewable capacity by 2022, including 100 GW solar, 60 GW wind, 10 GW biomass, and 5 GW of small hydro. By the second quarter of 2020, India reached around 36 GW solar capacity and 38 GW of wind, with states such as Karnataka and Andhra Pradesh already reaching over 20% of these sources in their electricity mix by 2019.

The most recent NEP issued in 2018 (CEA, 2018a) stated that the MoP had decided that all coal-based capacity addition during the years 2017-22 and subsequent Plan periods should be SC or USC units. Furthermore, given the large renewable capacity now targeted for 2022, and the 48 GW of coal capacity under construction at the time (taking the utility fleet to around 217 GW in 2022), it was concluded that no new net coal capacity would be needed by 2022, even after taking into account up to 22.7 GW of coal retirements in the period. However, if a maximum of 25.6 GW of coal retirements were achieved by 2027, the report suggests that over 46 GW of conventional capacity – either from coal or peaking sources – would be required during the 2022-27 period. Another 100 GW of renewable capacity was also projected to come online by 2027.

In January 2020, the CEA released a revised outlook for the power sector to coincide with a newly announced government target to achieve 450 GW of renewable capacity in 2030 – almost entirely from wind and solar, but also including energy storage. This ‘Report on optimal generation capacity mix for 2029-2030’ shows coal capacity growing to 266 GW by the target year, while taking into account the coal retirement targets from NEP 2018 (Figure 10).

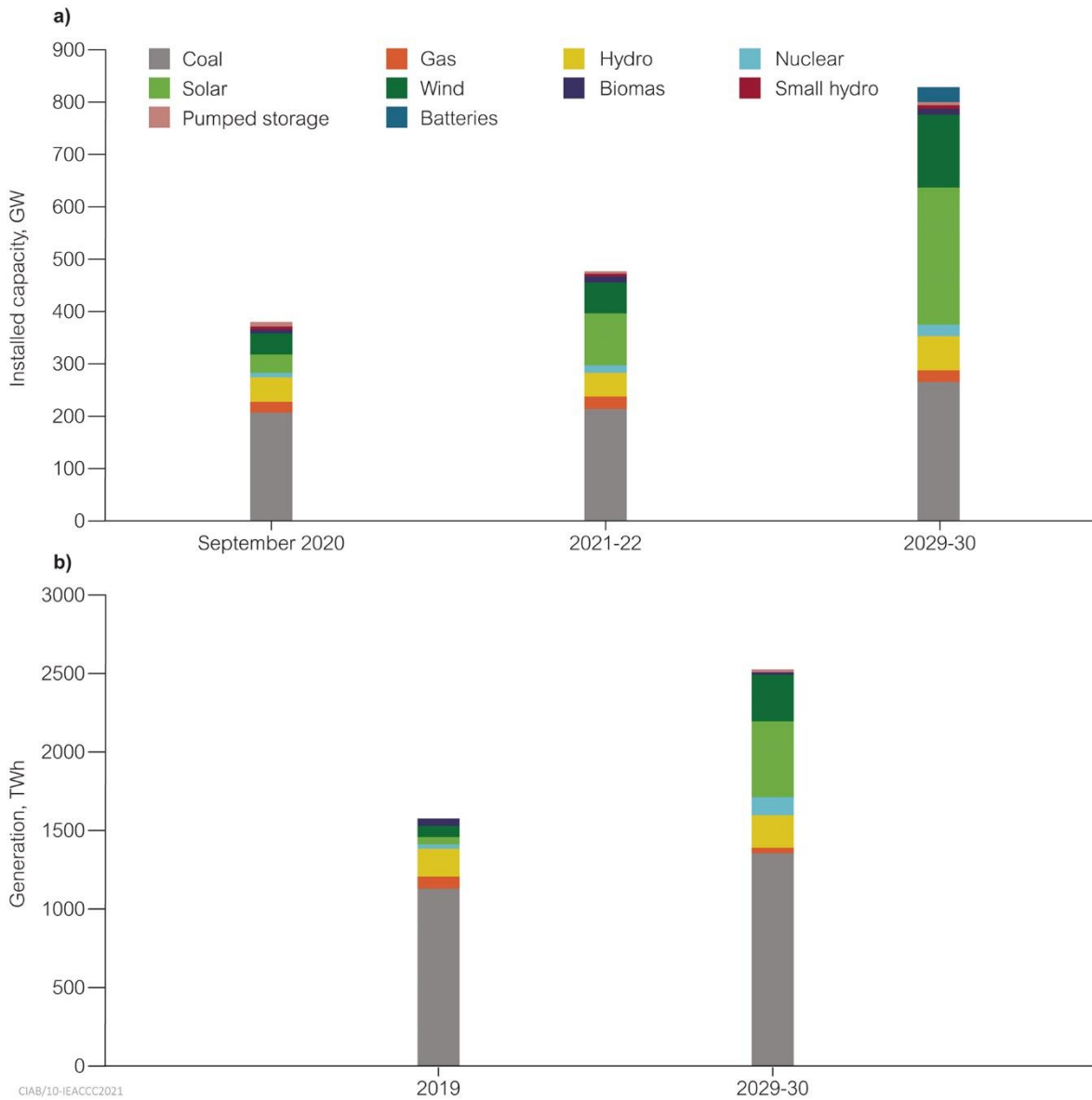


Figure 10 The breakdown of India’s utility power generation by a) installed capacity and b) total generation, with a projection for the optimal mix in 2029-30 from CEA, 2020b (current status from CEA, 2020a and IEA, 2020b)

NITI Aayog

The National Institution for Transforming India (NITI) Aayog was formed in 2015 as a leading advisory group to design strategic and long-term policies for the Government of India (GoI). It replaced the Planning Commission which had been the architect of India's Five-Year Plans. NITI Aayog provides the central vision to tackle India's challenges with regards to energy policy, regional economic growth, agriculture, education, health, nutrition, trade, and employment. The formation of NITI Aayog coincided with the launch of the United Nations Sustainable Development Goals (SDGs) in 2015 and is a strong indication of the priorities of the GoI (NITI Aayog, 2017).

In 2017, NITI Aayog (2017a) formulated the draft National Energy Policy which was presented to the GoI in 2019 and is discussed in more detail in Chapter 6. The draft Policy is a framework to guide policy making, implementation and enforcement across central and state governments. It set out the objectives and the strategy of energy development in India for the medium term from 2017 to 2040. The document stated that efficient technologies, such as USC technology, IGCC and large units would be gradually introduced for electricity generation as their cost effectiveness becomes established. The draft Policy also called for policy support for distributed generation and carbon capture and storage (CCS). It urged the GoI to reform the distribution sector and electricity pricing and subsidy systems in the medium run. However, the document was not formally adopted by the GoI.

When the 12th FYP concluded in 2017, instead of producing a new one, NITI Aayog launched a 3-year action plan, which would be part of a 7-year strategy paper and a 15-year vision document. The Vision, Strategy and Action Agenda sets the objectives and strategies of social and economic development of India. The 3-year Action Agenda offers proposals for policy support and policy changes necessary to achieve the objectives and goals of the Government. The 3-year Action Plan for 2018-20 (NITI Aayog, 2017b) called for the GoI to adopt cost-effective energy efficiency policy solutions. It encouraged the Government to improve the efficiency of thermal power plants by continuing its programmes of Renovation & Modernisation of existing plants and closing old, inefficient plants. The action plan also recommended that new power projects initiated during the Action Agenda period, especially if located in or near heavily populated areas, should use USC technology. In 2018, NITI Aayog (2018) published its Strategy for New India @75 which set targets to be achieved by 2022, the 75th anniversary year of India's independence. Again, energy efficiency is at the core of energy development strategies and some reform measures to the electricity market have also been proposed as a way forward. In October 2019, NITI Aayog started drafting the Vision Document 2035.

2.5.2 Climate change policies

In the 2009 Copenhagen Accord (UN Climate Change Conference of the Parties, COP15) India agreed a voluntary climate target requiring emissions intensity in 2020 (measured in kgCO₂/US\$ of GDP) to be 20–25% below the 2005 level (see Table 4). Between 2005 and 2020, absolute CO₂ emissions doubled from 1210 Mt to an estimated 2579 Mt. However, GDP (2010 US\$) more than doubled, leading to a reduction in emissions intensity of 22% from 1.09 kg/US\$ to 0.85 kg/US\$ (IEACCC based on ISOS, 2018) (see Figure 11).

Copenhagen Accord	2020 target(s)	20-25% below 2005 emissions intensity of GDP by 2020
		(258-279% above 1990 by 2020 excluding LULUCF)
		(71-81% above 2010 by 2030 excluding LULUCF)
	Coverage	Excluding agriculture sector
	Condition(s)	None
Paris Agreement	Ratified	Yes
	2030 unconditional target(s)	33-35% below 2005 emissions intensity of GDP by 2030
		(479-495% above 1990 by 2030 excluding LULUCF)
		(177-185% above 2010 by 2030 excluding LULUCF)
	2030 conditional target(s)	Non-fossil share of cumulative power generation capacity 40% by 2030
		(371-373% above 1990 by 2030 excluding LULUCF)
		(126-127% above 2010 by 2030 excluding LULUCF)
Condition(s)	Transfer of technology and low cost international finance including from GCF	
Coverage	Not specified	
LULUCF	Additional (cumulative) carbon sink of 2.5–3 GtCO ₂ -e by 2030	
Long-term goal(s)	Long-term goal(s)	Per capita emissions never to exceed those of the developed world
LULUCF = land use, land use change and forestry		

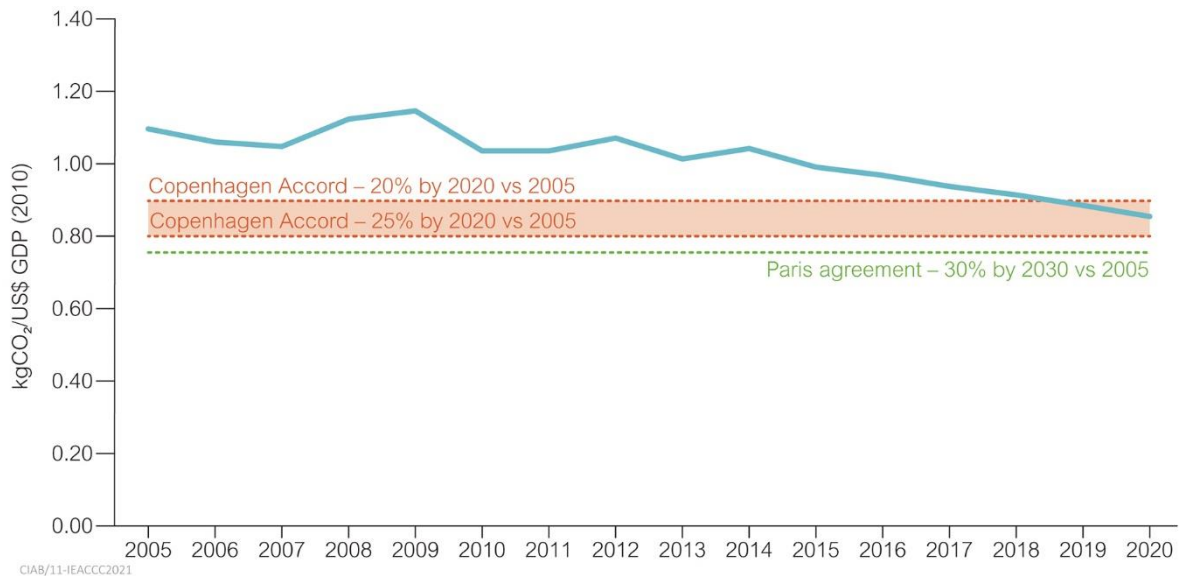


Figure 11 CO₂ intensity of GDP in India 2005-20 compared with climate targets (authors' estimates based on WorldBank, 2020; ICOS, 2018; Levin and Lebling, 2019; IEA, 2020a; Economic Times, 2020a; Orr, 2019)

India has also been a partial success story in meeting its Paris Agreement targets pledged at the 2015 Conference of the Parties (COP21). The Nationally Determined Contribution (NDC) includes a reduction in the emissions intensity of GDP by 30–35% by 2030 from 2005 levels (*see* Table 4). The NDC also stipulates a broader strategy to innovate and develop energy technologies and manufacturing in India and to create a carbon sink of 2.5–3.0 billion tonnes of CO₂ equivalent (GtCO₂-e). By 2030, the intention is also for 40% of installed generating capacity to be non-fossil sources. Although this target was made conditional on international support and funding, it will soon be significantly surpassed if the current renewable expansion targets are met (*refer back to* Figure 10, page 41).

While India appears to be on a pathway to lower emissions intensity, the CEA remains tasked with transforming the Indian power sector into a flexible system that can accommodate 160 GW of variable renewable energy sources on the grid by 2022, and over 400 GW by 2030 (CEA, 2019a). India's commitment to building an efficient, flexible, and clean coal fleet is evident in its NDC, and is being pursued through a wide range of government programmes and initiatives for power plant improvement. These are described in more detail in the following chapters.

2.6 KEY MESSAGES

- There is a clear trend in Indian energy policy towards promoting more efficient power generation.
- Deployment of clean coal technologies is increasingly highlighted in recent energy policies in India.
- Energy policies aim to make India relatively more self-sufficient with regards to energy supplies, making greater use of indigenous coal and renewable power.

- Electricity access for all is mostly successful, but per capita consumption remains low, and supply reliability is a challenge. Affordable and reliable power will remain key objectives for the GoI.
- India is a success story in many respects; power station developments have meant that there is abundant generating capacity which is catching up with peak demand. Grid losses, unmetered use, and free electricity made available to deprived households could pose a continuing financial challenge for distribution companies.
- Real GDP growth is rising faster than CO₂ emissions which fosters a lower carbon intensive pathway for the economy. Targets for the Copenhagen Accord are already met, but lower CO₂ per GDP is required to meet the Paris Agreement goals.
- The role of coal power will remain significant with a dual role of providing baseload and flexible load to balance the increased amount of renewable power on the grid.

3 RAISING THE EFFICIENCY OF THE COAL FLEET

3.1 THE POTENTIAL FOR CO₂ REDUCTION

The significant increase in India’s SC plant capacity over the last decade has led to a clear increase in the average efficiency of the coal fleet, although such estimates are based on various assumptions, and should be treated with some caution. The IEA efficiency data shown in Figure 12 indicates India’s average coal power efficiency reaching the level of the USA in 2016, before it appears to be corrected slightly downwards in 2018. For major coal-using countries such as India, increases in coal fleet efficiency can represent a significant reduction in CO₂ emissions, and there remains considerable room for further gains through the adoption of existing high-efficiency technologies. Figure 13 (on the following page) shows how the CO₂ intensity of a typical hard coal-fired plant reduces with increasing thermal efficiency. The improvement in India’s coal fleet efficiency from 2010 to 2018, corresponding with a period of rapid growth in coal generation, has avoided over 100 Mt of CO₂, or roughly a 10% reduction in India’s total emissions from coal. If the fleet efficiency could continue to climb to the level achieved by Japan, a further 180 Mt of CO₂ could be avoided (based on 2018 generation levels). Such a high-efficiency pathway is explored in more detail in Chapter 6.

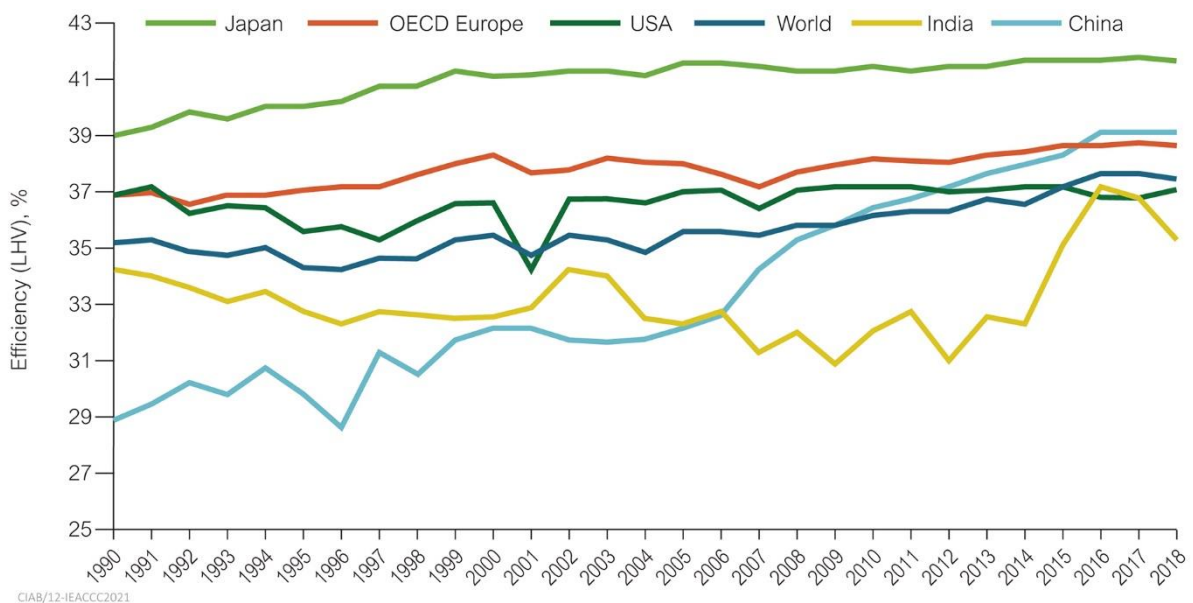


Figure 12 Efficiency improvement of India’s coal fleet since 2000, with other countries for comparison (IEA, 2020b)

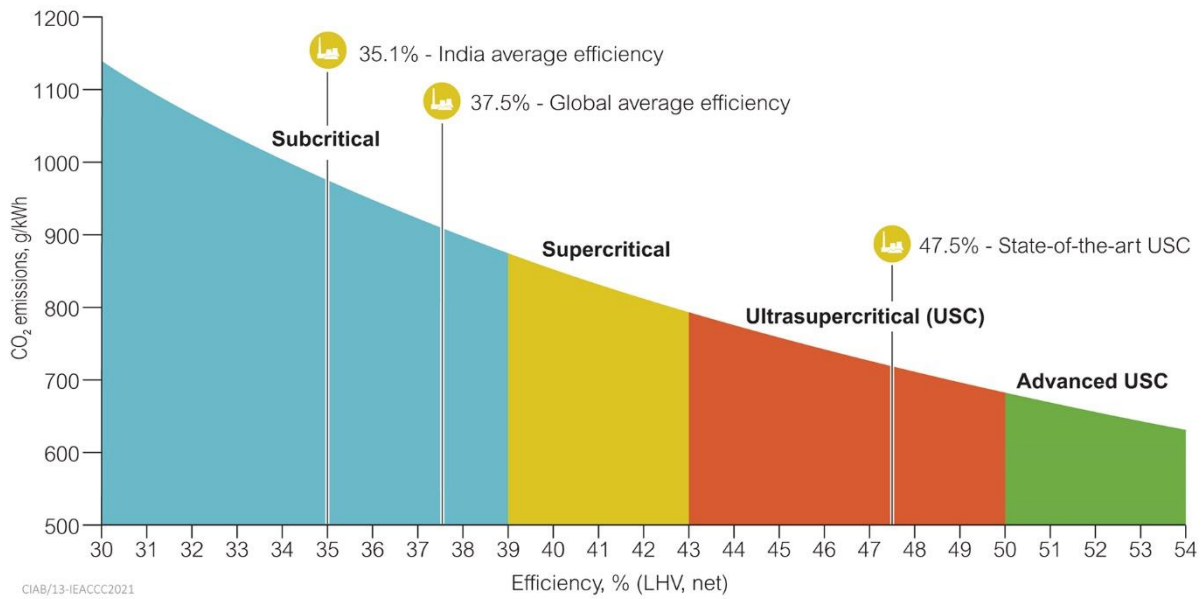


Figure 13 CO₂ reductions achievable with increasing coal plant efficiency (IEACCC, 2020)

There are two distinct approaches to raising the efficiency of the coal fleet. Firstly, existing units can be upgraded with the best available efficiency saving technologies, of which the most effective available options are outlined in Section 3.4. Secondly, new capacity can make use of the most efficient plant designs, including USC and integrated gasification combined cycle (IGCC) technologies. State-of-the-art USC units are currently able to achieve over 47% efficiency (LHV, net) depending on factors such as coal type and ambient conditions, while new IGCC units under construction in Japan are designed to achieve 48%. Lastly, the role played by high-efficiency new plant can be enhanced by accelerating the retirement of ageing subcritical units. As shown in Section 2.3, India has a significant proportion of subcritical capacity built within the last 15 years (48% of the total fleet). A key factor in coal plant modernisation is therefore the balance between choosing to upgrade this capacity or to accelerate its early retirement and replacement.

In recent years, India has actively pursued unit upgrading, retiring of subcritical units, and deployment of high efficiency plant in order to raise the efficiency of its fleet. This chapter describes current policy and market drivers behind these trends in detail, lays out potential strategies for more ambitious efficiency improvements, and briefly outlines the high-efficiency technologies available for both new and existing plants. As India rapidly expands its wind and solar capacity in the next decade, the role of coal plants is increasingly changing from baseload generation to providing flexible back-up and enhancing energy security – this new challenge to maintaining high efficiency operation is also addressed.

3.2 DRIVERS FOR EFFICIENCY IMPROVEMENTS

3.2.1 Market factors

For coal plant owners and developers, more efficient technologies represent an opportunity to maximise revenue, as less coal is consumed for every unit of power generated. In a fully competitive market with merit order dispatch, reduced power generation costs should also directly translate to increased operating hours. The additional capital cost of unit upgrades or SC technology should therefore be paid back over a given period of time. However, in India's highly regulated and cost-based market, the value of efficiency improvements is less straight-forward. For the majority of units operating under the system of regulated tariffs (most public sector units and some IPPs), the energy charge component of the tariff is based on fuel cost and benchmark heat rate 'norms' for various unit categories based on size and technology. Units can therefore gain additional revenue from operating at above their benchmark efficiency. However, the benchmark heat rates have not been tightened for most categories in recent years, and they are based on historical operating experience rather than global technology benchmarks, so are not currently a strong driver of efficiency improvements (Sinha, 2020a). A lack of transparency around actual unit heat rates is often criticised as preventing the setting of ambitious efficiency benchmarks, as only overall power plant data must be disclosed to the regulator (CSE, 2020a).

Coal plants with lower energy charges should generally gain more operating hours, as discoms preferentially dispatch the plants with which they have long-term contracts according to their energy charges, establishing a form of merit order. Just as in fully liberalised markets, however, this system does not necessarily favour more efficient plants, as there are many mine-mouth units which easily offset their low efficiency with low coal costs. Many newer SC plants are located further from coal fields and closer to demand centres and, combined with the high costs of coal transportation in India, this can result in high-efficiency plants having a low utilisation rate. This effect is also seen in Germany, where inefficient mine-mouth lignite units can run as baseload, while efficient hard coal units located closer to demand centres are obliged to load cycle. In India, true merit order dispatch is also disrupted by plants with power purchase agreements (PPAs) which require discoms to purchase a given quantity of generation. Furthermore, due to the state-oriented dispatch system, there is potential for more efficient plants in neighbouring states to be under-utilised while less efficient in-state plants are used. The 2019 implementation of security-constrained economic (day-ahead) dispatch has helped reduce this issue for interstate generating stations (ISGS) under CERC jurisdiction, but it remains for state-regulated plants.

Despite the muted impact of market forces in the Indian power sector, they have helped drive the shift towards SC technology over the last decade, as targeted by the Ministry of Power (see Section 2.5.1). The majority of plants deployed in this period have had to compete for PPAs or power sale agreements (PSAs) through a bidding process based on a levelised, single-part tariff (including capital and

operating costs). There has therefore been a growing incentive to maximise plant efficiency to obtain these long-term contracts (Sinha, 2020a).

The ongoing shift towards a more liberalised market structure, including the phase-out of regulated tariffs and implementation of more nationwide, merit-order dispatch, should work to encourage efficiency improvements in existing plant and support the ongoing predominance of SC or USC technology for new plants. However, in order to ensure efficient plant is favoured over less efficient plant, regardless of fuel costs, some stakeholders have suggested a form of merit order based on plant efficiency could be introduced (CSE, 2020a; Kendhe, 2020).

3.2.2 Plant upgrading incentives

The Renovation & Modernisation (R&M) programme and the Life Extension (LE) programme for existing thermal power plants were initiated in 1984 as a centrally sponsored programme during the 7th FYP and they continue to this day. The objective of the R&M programme is to support the upgrade and retrofit of existing power plants with modern technologies to improve their performance in terms of output, efficiency, reliability and availability, and to comply with stricter environmental standards. The aim of the LE is to extend the operation of the old plants beyond their original designed life. Providing an application for a plant to conduct R&M or LE work is accepted by CERC and the purchasing discom, the capital costs of the upgrades can be passed onto the regulated tariff (through additional capitalisation). Alternatively, units can opt for a ‘special allowance’ to cover general component replacements and upgrades, received either as a one-time payment or at a rate of Rs 9.5 lakh per MW (12,800 US\$/MW) on the wholesale tariff (set for 2019-24) (CERC, 2019). These schemes are therefore not available for newer plants under the competitively determined tariffs. These plants must price potential upgrades into their tariff bids, or invest based on the revenue associated with reduced coal consumption.

The number of plants targeted to undergo R&M or LE are specified in each FYP and National Electricity Plan (NEP). In the 2018 NEP, the CEA identified 35 thermal generating units with a total capacity of 7570 MW for LE works and 37 units with a capacity of 7359 MW for R&M works for the period 2017-22 (CEA, 2018a). In recently proposed CERC regulations, units reaching 25 years of operational life must choose to either undergo R&M, receive the special allowance for upgrades, or adopt a single-part tariff which includes fixed and variable costs (this is regarded as less profitable than the two-part tariff should the plant load factor (PLF) be lower than benchmark values) (CERC, 2019).

3.2.3 Retirement of inefficient units

As discussed in Chapter 2, in recent years the CEA has raised its ambitions for retiring ageing, inefficient coal units, with a strong focus on suppressing any units which have reached over 25 years of operation. While less than 4 GW of capacity was phased out in the 12th FYP period to 2017, over 22 GW is considered in the period to 2022. Of this, only 5.9 GW is based on age criteria, with a further 16.8 GW assessed to have insufficient space for installation of the flue gas desulphurisation (FGD)

equipment required by the 2015 emissions standards (see Chapter 4). From 2022 to 2027, a further 25.8 GW could be decommissioned, if the 25-year age limit is applied rigorously (CEA, 2018a).

In practice, retiring old units can be challenging, particularly in regions where all existing capacity is required to meet peak demand, making a transition period of reduced supply highly undesirable. Furthermore, as inefficient units are often located at the pit-head and have low fuel costs, they can represent strong sources of revenue for generating companies, who may be reluctant to close them while they continue to operate profitably. Older, fully depreciated plants (over 25 years) also represent good value for discoms, as the fixed cost component of the tariff no longer covers the capital cost of the plant. Even if a generating company is motivated to decommission an old unit and replace with new SC capacity, there may be space restrictions at the existing site, challenges with permitting for a new plant in the vicinity (particularly if a heavily industrialised area), and issues with maintaining a coal linkage agreement for the new capacity. Indeed, engagement with generating companies suggests that, while most companies favour a policy of high-efficiency replacements rather than upgrading and life extension, the former presents greater regulatory challenges.

Some measures have recently been adopted or proposed to encourage retirement of ageing units, including a MoC policy on the automatic transfer of coal linkages from scrapped units to their SC replacements (CEA, 2018a). This policy requires the retired capacity to represent at least half of the new capacity.

3.2.4 Perform Achieve and Trade

As part of the National Mission on Enhanced Energy Efficiency, the Perform Achieve and Trade (PAT) is a programme launched by the Bureau of Energy Efficiency to reduce energy consumption and promote enhanced energy efficiency among energy intensive industries, including the power sector. PAT uses a cap-and-trade mechanism whereby plants are assigned an energy consumption target. If a plant beats its target over the three-year compliance period, it receives Energy Savings Certificates (ESCerts) for excess savings which can be traded or banked for the next cycle. The CERC approved the trading of ESCerts in February 2017 (Mathur, 2017; NITI Aayog, 2017b). PAT cycle I ran from 2012 to 2015 and involved 478 designated consumers (DCs) in eight energy intensive sectors, accounting for 35% of the total energy use in India. 144 of the DCs were thermal power plants, including 97 coal or lignite plants. BEE (nd) claimed that PAT cycle I achieved energy savings of 8.67 Mtoe, which was 30% higher than the targeted 6.886 Mtoe in energy saving and equivalent to CO₂ emissions reduction of 31 Mt. However, the scheme also attracted criticism as the price of ESCerts collapsed, resulting in non-compliant emitters spending less than those which had invested in more energy efficient technology (Kujol and others, 2018). Analysis by CSE suggested that PAT Cycle I required a small average heat rate reduction of around 4–5% in participating thermal power plants, but the sector still contributed around half of the total emissions reductions achieved (CSE, 2020a).

PAT cycle II ran from 2016 to 2019 covering 621 DCs from 11 sectors (adding three new sectors) and targeted energy savings of 8.869 Mtoe (BEE, nd). The results from this cycle are not yet available, but it is thought that the level of efficiency improvement in the power sector will be similar to the first cycle (CSE, 2020a). It is proposed that PAT cycle III be implemented on a rolling basis (that is, new DCs will be included annually). In total, there would be 737 DCs (621 DCs from PAT Cycle II plus 116 new DCs of PAT cycle III) participating under PAT scheme. These 116 DCs consume about 35 Mtoe energy while they have been assigned an energy saving target of 1.06 Mtoe at the end of the cycle. In the draft National Energy Policy, NITI Aayog recommended expansion of the PAT scheme to cover 80% of all industrial consumption, and raising the efficiency targets in line with technological advances of processes. The scheme has the potential to play an important role in driving power plant upgrading, if sufficiently ambitious efficiency targets are set, and properly enforced.

3.2.5 Efficiency standards

Some countries have employed clear targets or regulatory standards for the efficiencies at which new or existing coal units are permitted to operate. Most notably, Japan set standards in 2014 which required all new units to have a thermal efficiency of more than 42.0% (HHV), while China has regulations effectively requiring USC technology for large units, as well as setting an average efficiency target for the whole fleet (Zhu, 2020a).

In October 2020, India's Ministry of Power indicated that it is considering applying a heat rate cap of 2600 kcal/kWh (10.9 MJ/kWh), which equates to an efficiency of 33.1% (HHV). Although this target is eminently achievable for subcritical units, up to 10 GW of capacity is currently thought to be operating at higher heat rates. Further tightening of this cap could represent an effective regulatory approach to driving efficiency improvement of the fleet (Singh, 2020).

Although the GoI has placed a strong focus on transitioning to large SC and USC and IGCC technologies for coal power, both in the Paris Agreement NDC and other long-term strategy documents, it is still legally possible to deploy less efficient technologies in the country. Nevertheless, as generating companies have become more familiar with commissioning and operating SC plants, and the economic competitiveness of such units has grown as capital costs are optimised, new subcritical capacity in the utility sector is highly unlikely. However, subcritical captive units may still be built by some industrial consumers (Kendhe, 2020).

3.2.6 Carbon pricing

Forms of carbon pricing have been widely implemented around the world, including cap-and-trade systems such as the EU Emissions Trading System and direct carbon taxes on industrial emissions. In practice, carbon pricing is not proven to be effective in driving reductions in the emissions intensity of coal power; it more leads to coal-to-gas switching, as observed in the UK and more recently, Germany. China's CO₂ emissions trading system, expected to come into force for the power sector in 2021, will allocate CO₂ allowances on the basis of benchmark efficiencies for various generator

categories (such as coal unit size). This kind of system is more likely to lead to efficiency improvements within each category, although it could also have the undesirable outcome of favouring higher-performing units in lower efficiency categories (Metzger, 2020).

While there is no explicit carbon pricing in India, a tax on coal producers introduced in 2010 and known as the ‘coal cess’ (originally the clean energy cess) is often described as a form of shadow carbon tax. A cess is a tax in India which is charged over and above the base tax liability and is usually imposed to raise funds for a specific purpose. At the current rate of 400 Rs/t of coal, the coal cess equates to just over 3 US\$/tCO₂ (Tongia and others, 2020). Although the revenues from this tax were originally intended to be channelled into clean energy projects, it is currently used for compensating state budget deficits associated with the 2017 goods and services tax (GST). Owing to coal’s prevalence as an energy source in India, the coal cess covers 70% of the country’s emissions. While there is limited scope for an augmented coal cess to drive efficiency improvements, there is considerable industry stakeholder support for using its revenues to assist with efficiency improvements or pollutant controls.

3.2.7 Case study – Ultra Mega Power Projects

India has issued policies to encourage investment in power generation which can also act as drivers for HELE deployment. For example, the Mega Power Policy was introduced in 1995 to accelerate investment in power generation and it provides incentives to those building power plants with a capacity of 1000 MWe or more. The Power Trading Company was formed to act as an intermediary between the private investors in mega power plants and the SEBs.

In 2005, the Ultra Mega Power Projects (UMPP) was launched to accelerate power capacity expansion. UMPPs are coal-fired SC power plant projects with a capacity of ≥ 4000 MWe that are inter-state power projects for either minemouth power plants using domestic coal, or coastal projects based on imported coal. The most distinct aspect of UMPPs is that many statutory/administrative clearances are obtained prior to award of the project. To shorten the project time, a Special Purpose Vehicle (SPV) was created and designated for each UMPP to take charge of completing the necessary activities such as acquisition of land, obtaining coal blocks, receiving environmental permissions and arranging the PPA. Once the competitive bidding process was completed, the CERC would approve the award of the UMPP and the tariff (IEA, 2012). However, although a total of 16 UMPPs were envisaged, only two have been built and are now operational (CEA, 2019b). They are the 6 x 660 MW Sasan UMPP and the 5 x 800 MW Mundra UMPP. The rest have either been cancelled or shelved.

The UMPP programme was not a widespread success for various reasons. A key one is that the early bidding guidelines based on a design, build, finance, operate and transfer model, failed to encourage lenders to fund the expensive capital investment required for 4000 MW power projects if the developer did not have ownership of the asset (Mukul, 2015; Sharda and Buckley, 2016). The guidelines mandated that ownership of the plant be transferred to the government after the concession period, a stipulation that limited potential bidders from obtaining finance. Developers were also

restricted in the amount of fuel cost increases they could pass onto consumers. This limitation would expose the plants' operator to financial risks resulting from rising fuel costs.

A key feature of the UMPP plan was to reduce pre-construction risks by completing activities such as land acquisition, obtaining coal blocks, receiving environmental permissions and arranging the PPA before inviting competitive bids. However, issues related to these pre-construction risks had been major roadblocks for private investors trying to raise finance for the projects. Problems arose as the risks remained, such as land acquisition and securing coal supply, which weakened the confidence of lenders and investors (CEA, 2013; Mukul, 2015; Malik, 2017). For example, Reliance Power was awarded the Tilaiya UMPP in 2009 but the company divested its holding in Tilaiya UMPP in 2018 due to severe delays in land acquisition and transfer by the Jharkhand government (Jai, 2018b).

Delays were common in the UMPP bidding and developing process, leading to increased costs. The estimated capital cost of UMPPs increased by 35% from Rs 20,000 crore (US\$3 billion) in 2013-14 to Rs 27,000 crore (US\$4 billion) in 2015-16 (Sharda and Buckley, 2016).

The bidding guidelines were revised in 2015 to address the concerns of investors and lenders and covered areas of risk such as fuel price variation, fixed charge quote, ownership of asset, incentives for performance, land acquisition and termination of contract (Mukul, 2015). However, by this time, a significant amount of new generation capacity had been added and there had also been a rapid expansion of renewable power. As described in Section 2.3.2, new capacity additions outpaced the demand for electricity. As a result, utilisation of the coal fleet in India fell from around 78% in 2007-08 to just under 60% by 2016-17 which undermined the financial performance of generating companies (CEA, 2016; Zhu, 2020a). The sluggish electricity market made large projects like UMPPs unattractive.

Another factor is that the Indian power sector has become highly leveraged since 2007 when the first UMPPs were awarded. The average debt-to-equity ratio of six of the top publicly listed power companies increased by 80% from 1.5 in 2010-11 to 2.7 in 2015-16 (Sharda and Buckley, 2016). The power companies thus lost interest in UMPPs as they could not take on more capital expenditure. Also at this time, Indian domestic banks were beset by problems associated with bad debts which prompted them to take a cautious approach towards lending, especially to the already stressed power sector (Sharda and Buckley, 2016). This increased the difficulty for the proposed UMPPs to raise debt financing.

The revised UMPP guidelines addressed some of the roadblock problems but new issues were generated. In particular, the new guidelines did not fully address the key issue of land acquisition. The revised land acquisition guidelines segregate operating and infrastructure assets into two separate SPVs. Thus the land for the coal block and the power plant would be housed under one SPV, while the plant would be developed under another operating SPV. The result would lead to separate mortgages for the land and the power plant, which would be a challenge when selling the asset (Mukul, 2015; Malik, 2017).

Furthermore, the viability of UMPPs was also reduced by the creation of a coal tax in 2010 and then doubling of the coal tax three times in four years between 2014-15 and 2016-17 (Sharda and Buckley, 2016). The possibility of future rises in the coal tax discouraged investment in UMPPs.

The two UMPP plants that have been built and are operational have financial difficulties and have been marred by serious environmental and social concerns. Tata Power, which operates the Mundra UMPP in Gujarat which came online in 2012-13, has operated at a loss from the beginning due to the rising price of imported coal on which it relies. Within six months of starting operation, the company had lost around Rs 3,000 crore of equity investment in the Mundra project (Economic Times, 2012). Tata Power demanded an increase in the tariff for electricity generated from its Mundra UMPP to make up for the losses due to higher coal costs (Malik, 2017) and in January 2020, threatened to shut the power plant (CFA, 2020). In March 2020, Tata Power and the five states that purchase power from the Mundra UMPP agreed to find a solution to the tariff problem. Tata Power moved one step closer to tariff revision when the Maharashtra State Electricity Distribution Company received the go-ahead from the state government to revise tariffs for Mundra UMPP (Pillay, 2020).

The Mundra UMPP has also received environmental complaints and a court battle continues (CFA, 2020).

Sasan UMPP, owned and operated by Reliance Power, consists of six 660 MW SC coal-fired units and had two government-allocated coal mines (Patel, 2016). The developer had to overcome several hurdles to raise debt financing and the project incurred a construction cost overrun of US\$1.45 billion, nearly 32% of the original project cost. Costs for land acquisition for the coal mine also increased, and the project suffered when a custom duty exemption for coal mining equipment was lost unexpectedly. The Chhatrasal coal block was removed from Reliance Power's allocation by the GoI which caused further problems leading to Reliance Power wanting the state-owned Power Finance Corporation to acquire the entire stake of Sasan UMPP (Mukul, 2015). Finally, the project developers were accused of various actions including forced moving with inadequate compensation of the locals, a poor health and safety record for employees and causing pollution (Patel, 2016).

Thus, the financial stress, litigation and other issues faced by the two UMPP operators would likely discourage potential investors in future UMPP schemes, as would the decline in capacity expansion.

The lack of success of UMPPs highlights the lack of confidence in investors due to inconsistent government policies, ambiguous land acquisition rules, difficulties raising debt financing and certain litigation. They are also unlikely to proceed as the demand for expansion of capacity has waned.

3.2.8 Summary

As India transitions to a more competitive power market, more efficient coal units will increasingly be favoured in merit order dispatch, providing a market-based incentive for unit upgrades and increasingly favouring SC and USC for new builds. However, it is clear that additional policy

instruments will be required to accelerate the retirement of ageing, inefficient capacity (which often remains profitable), encourage the uptake of newer technologies, and prevent plants with access to low-cost coal from out-competing more efficient units near demand centres. Existing policies such as the PAT efficiency credit scheme and the recently proposed heat rate cap are promising options which can be progressively made more ambitious. In future, a form of carbon pricing on power sector emissions may also play a role in modernising the sector, especially given the limited scope for coal-to-gas switching in India. Revenues from carbon pricing initiatives (such as the sale of allowances), or from the existing coal cess, can also be used to support direct government support for activities such as efficiency R&D and demonstration, and technical capacity building. In addition to these incentives, regulatory reforms are required to help ease the process of unit retirement and replacement.

3.3 CHALLENGES TO INCREASING EFFICIENCY

3.3.1 Financial and institutional challenges

The financial difficulties facing India's distribution and generating companies, as outlined in Chapter 2 present a challenging environment for modernisation of the coal fleet. The prevailing low operating hours for coal units, shortage of financing and liquidity in the sector, and limited prospects for new PPAs with discoms are some of the principal challenges facing generators wishing to invest in new, high-efficiency capacity.

Most finance for investment in the coal power sector comes from public banks and government-owned financial institutions, including the State Bank of India and the Power Finance Corporation. While a significant proportion of coal power financing was still associated with domestic commercial banks (~35%) in 2018, there is declining interest from this sector, which is primarily lending to renewable-based projects (CFA, 2019). Coal projects in the state and central generating sectors are generally self-financed or able to obtain public finance, in contrast to IPPs, which have struggled to obtain backing for new plants or necessary equipment upgrades. International finance has tended to play a less significant role than in other developing countries, although Japanese banks and export credit agencies have backed several projects based on technology supplied from Japan, with the Japan Bank of International Commerce (JBIC) forming a strategic partnership with India's ICICI bank in 2009 (Baruya, 2017; Ranamurthy and Singh, 2019). In 2020, NTPC raised its largest ever foreign currency loan in the form of a syndicated loan of Japanese yen worth US\$750 million, aimed at financing hydro projects, USC plant, and the installation of flue gas desulphurisation (FGD) (see Chapter 4) (ET Energy World, 2020). Later in the same year, the company obtained another £482 million loan (roughly US\$650 million) from JBIC and Japanese commercial banks, for which FGD was also considered a key target (Shukla, 2020). Financing from Chinese export and development banks has also been obtained for several IPP-led projects using Chinese equipment suppliers, including those of CLP India, Lanco, and Reliance Power (GEM, 2020).

3.3.2 Technical challenges

Most Indian power plants burn domestic coal with a high ash content which is also very abrasive due to the presence of alpha-quartz. The high ash content of Indian coal means that a longer residence time in the furnace is needed for the carbon to burn out, so the boilers are around 20% larger than those running on lower ash coal (Cornot-Gandolphe, 2016). When high-ash coal is burnt, the temperature in the burner near-field decreases, leading to a lower yield of volatile matter, which translates to less stable combustion than lower ash coals (Daury, 2018). The abrasive nature of the ash also causes erosion of handling, milling, and pulverised fuel feed equipment. Additionally, there are other issues associated with the quality and consistency of coal supplies which can be alleviated by better sampling and monitoring of the coal quality throughout the supply chain. It is not uncommon for power plant operators to experience coal supply shortages, where stocks have been run down to only a few days. Water constraints are a broader challenge faced by plant operators, coal producers and coal washing facilities. As the deployment of intermittent renewable capacity progresses, increasingly flexible operation of coal plants can exaggerate existing challenges and bring additional problems such as flame stability at lower loads, increased life consumption of components, challenges for pollution control technologies and decreased plant efficiency (Storm, 2020; Wiatros-Motyka 2019).

Benefits of coal washing

Washed thermal coals may still contain around 34% ash, but a 40–45% content in unwashed coal means the reductions in mineral matter can be significant.

Commercial trials to demonstrate the benefits of using washed coal took place at the 250 MW Satpura power plant of the Madhya Pradesh State Electricity Board using washed coal from the beneficiation plant at the Piparwar mine. The resulting improvements in plant performance included better plant availability and higher utilisation, improved coal consumption, the elimination of the need for fuel oil, and improved coal mill efficiency; the results are shown in Table 5 (CPSI, 2020).

TABLE 5 PERFORMANCE IMPROVEMENT AT SATPURA POWER PLANT (CPSI, 2020)	
Parameter	Plant Improvement
Plant utilisation	Increase from 73% to 96%
Coal consumption per kWh	Fall of 0.77 kg/kWh to 0.553 kg/kWh
Reduced fuel oil	From 5 ml per kWh to 0.0 ml
Coal mill operation	Reduction in units required from 5 to 4
Coal mill rejects	Reduced from 0.35% to 0.031%
Particulate emissions	Reduced from 29.78 mg/m ³ to 17.23 mg/m ³
Alpha quartz content	Reduced from 14.5% to 11%
Detrimental performance to boiler performance, slagging, boiler tube leakage, clinker formation, abnormal erosion	None detected

APGENCO (2019a,b) also quantified the environmental benefits of using washed domestic coal (34% ash, 0.62% S) compared with a blend of domestic raw coal (38% ash, 0.62% S) and imported coal (16% ash, 0.8% S) for a proposed 800 MW Vijayawada coal plant. Fuel consumption (t/d) and SO₂ emissions (g/s) fell by 14.6%, ash production (t/d) fell by 23.4%, while NO_x emissions (g/s) declined by 41.9%. The CEA (2019a) has also reported that coal throughput is 36% higher in plants designed for domestic coal compared to those designed for imported coals. Plants designed for Indian coals used 0.654 kg coal/kWh, compared with 0.48 kg coal/kWh for those firing imported coals. The difference in throughput, compounded by the higher mineral matter content of domestic products adds a considerable burden of mass to the storage and handling systems, and as mentioned throughout this report, increases wear on the coal milling and fuel feed systems as well as the downstream PM pollution controls after combustion.

Domestic coal quality is part of the wider agenda of the GoI to reduce the cost of thermal power generation and solve various other challenges such as making wholesale power supplies affordable for the financially stressed discoms (GoI, 2018). Thus, in 2016, the GoI introduced third-party sampling by the Central Institute of Mining and Fuel Research (CIMFR), among other measures. The CIMFR, Coal India Ltd and the NTPC entered a tripartite agreement to improve the quality of coal through more thorough sampling and testing at a national level. The scheme has met with some success. For example in 2017, test results for coal supplies from the CIL subsidiary, South Eastern Coalfields Ltd (SECL), showed that 90% of coal samples between September 2016 and January 2017 were found to be substandard by the CIMFR (Patel, 2017). Generators can now raise concerns regarding the oversizing of coal, as well as substandard coal quality. In addition, the average specific coal consumption at power stations has improved by 6–8% (GoI, 2018). However, it is not clear how much of this improvement is due to better coal quality and how much is attributed to the rising efficiency of the fleet.

As evidence shows, coal preparation alleviates many of the problems associated with raw coal, including sizing and meeting quality criteria demanded by the buyer. Sizing coal correctly provides a more uniform product that is better for coal handling, storage, blending, and allows a more effective operation of coal mills at the power plant.

3.4 UPGRADING EXISTING PLANTS

The efficiencies of coal-fired plants normally decrease over time as components deteriorate with age and use, but some plants are also operated without ensuring ideal conditions for maximising longevity and performance. They may also suffer from inadequate maintenance and missed opportunities for retrofitting with modern systems, and so on, as noted by Henderson (2020). Additionally, a growing number of plants run in flexible mode to balance the increasing amount of intermittent renewable sources such as wind and solar supplied to the grid. This is challenging for many reasons and impacts the plant efficiency. There are several near-term solutions to increase coal-fired plant efficiencies such

as improvement of O&M practices, instrumentation and control upgrades, ensuring correct coal fineness and mill performance, combustion optimisation, modification of the turbine or more substantial changes, which are usually needed in older plant and include retrofits of the boiler and the turbine. These issues and solutions are subjects of IEACCC reports by Henderson (2013), Wiatros-Motyka (2016, 2019, 2020) and Zhu (2020a).

3.4.1 Optimising combustion

Many methods to increase power plant efficiency are interconnected and need to be applied in synergy. For example, combustion optimisation which involves attention to mill performance, trimming of excess oxygen in the furnace, adjusting the air/fuel ratio and all air flows can improve plant efficiency by 1–2 percentage points. Such optimisation is usually achieved with advanced system controls and extensive use of sensors for improved data collection. More on combustion optimisation and how it can reduce emissions, especially those of NO_x is given in the Appendix.

3.4.2 Flue gas heat recovery and low pressure economisers

Flue gas heat recovery is a standard way to minimise heat loss from a coal-fired plant and increase efficiency; it can be effectively achieved using various forms of economiser. There are several different economisers currently in use globally, including high temperature and low pressure (low temperature) ones. Low pressure economisers can increase plant efficiency by up to 1.5-2.0 percentage points. They can be placed in different locations. Those which are located just upstream of the FGD achieve greater efficiency improvement as they extract heat from the low temperature flue gas (Wang and others, 2012). Such devices were designed with post-combustion CO₂ capture in mind and are increasingly popular on coal-fired plants, especially in China (Electrical4U, 2020).

3.4.3 Turbine retrofits

The turbine is ‘the weakest link’ in the steam cycle as its performance can decline significantly with time. Hence turbine upgrades and retrofits are well established means to increase the efficiency of a coal plant.

An important aspect of reliable, safe, efficient and flexible operation of the turbine is ensuring that the very small clearances between stationary and moving parts stay almost constant during variations in output. This requires careful design, smart seals and taking adequate measures to ensure uniform thermal loading (Žbik, 2017; Henderson, 2014; Lech, 2019). This is especially important for flexible operation; frequent start-stops of the unit increase wear on the turbine seals, but they are most prone to thermal deformation during cold start-ups (Henderson, 2014, 2018). Several smart seals such as retractable, anti-swirl and brush seals are available on the market. They are less prone to damage and allow the necessary clearances to remain almost the same during variations in load. As smart seals increase the turbine efficiency, they also result in decreased emissions of CO₂ from the power plant. For example, a 200 MW unit using such seals can save approximately 20,000 tCO₂/y (Lech, 2019).

Apart from replacing seals, utilities often retrofit new rotors and blades, inlet valves and the inner high-pressure intermediate-pressure (HP-IP) turbine casing. Such retrofits, depending on the initial condition and specific measures introduced, can increase plant efficiency by 4–5 percentage points.

For older units, turbine retrofits are accompanied by various additional efficiency improvement measures, including retrofitting boiler parts, condenser optimisation and new instrumentation and controls. Such upgrades not only increase efficiency but prolong the operating life of the plant.

Examples of turbine retrofits of subcritical units in India

Examples of modernisation and renovation work on two 200 MW class units in Ukai and Wanakbori are presented in Table 6. The work was carried out by GE and included retrofit of the steam turbine shaft line. Additionally, the owner, GSECL, decided to add an additional economiser bank to improve efficiency of the boiler. Together, this work resulted in significant gains, including:

- 14.43% improvement in heat rate;
- 5.3 percentage point increase in efficiency;
- coal savings of 110,000 t/y (US\$7 million) in Ukai unit 4 and 128,000 t/y in Wanakbori unit 3;
- reduced CO₂ emissions of 165,000 t/y (Ukai) and 192,000 t/y (Wanakbori);
- units running at 84% PLF (September to December 2017) due to raised efficiency;
- reduction in start-up time;
- 5% extra load can be generated if needed;
- unit life extended by 20–25 years; and
- return on investment in less than 2 years (Kendhe, 2020).

Details of the main performance parameters before and after the modernisation are given in Table 6.

Particulars	Ukai unit 4		Wanakbori unit 3	
	Before R&M	After R&M	Before R&M	After R&M
Capacity, MW	200	200	210	210
Boiler efficiency, %	83	87.32	83	87.32
Turbine heat rate, kcal/kWh	2265 (9477*)	1939 (8113)	2265 (9477*)	1950 (8159)
Unit heat rate (kcal/kWh)	2721 (11385*)	2320 (9707*)	2718 (11,372*)	2320 (9707*)
Variable cost, Rs/unit	3.28	2.88	3.62	3.10
Coal factor, kg/kWh	0.680	0.597	0.678	0.580
Coal consumption, t/h	136	119	142	122
Coal consumption per year, at 70% PLF, t	833,952	732,160	973,074	744,831
Amount of coal saved, t/y	101, 792		128,243	
Landed cost of coal	Rs 4350/Mt		Rs 4865/Mt	
Savings in fuel cost per year	Rs 44.28 crores		Rs 62.39 crores	
(* kJ/kWh)				

Similar renovation and modernisation work is being carried out by NTPC and GE in a joint venture on three 200 MW units at Ramagundam power station, owned by NTPC. All three units are over 30 years old and are expected to achieve similar improvements to those made at the Ukai and Wanakbori units.

3.4.4 Digitalisation

A suite of digital technologies such as Big data, Analytics and Artificial Intelligence (AI), Digital Twins, advanced monitoring and control have been developed and are being applied in power plants. These digital tools enable the automated collection, analysis and optimisation of power plant operations. They allow operators to visualise and simulate individual equipment, processes and an entire plant's operation, and to keep track of performance, operation and maintenance (O&M) needs. Advanced analytics using AI and machine learning can identify or predict any issues and determine the appropriate actions with real-time responses to prevent or resolve the problems. In general, digitalising a power plant can increase its efficiency by up to around 2–3 percentage points, while also lowering emissions of air pollutants and CO₂ (Lockwood, 2015; Zhu, 2020b). Digital power plants also have reduced maintenance requirements and lower generation costs. Therefore, digitalising power plants can maximise the potential performance and profitability of assets, power plants and fleets to achieve the best possible outcomes, which leads to increased efficiency, affordability, reliability, and sustainability. Digitalisation will transform power generation enabling future power plants to operate largely autonomously with economic and environmental benefits. Details on the latest developments in this field and some case studies of digitalising power plants are available in a recent report from the IEACCC by Zhu (2020b).

3.4.5 Other approaches

Other approaches to increase the efficiency of coal power plants include reducing auxiliary power consumption and optimisation of the condenser. The first can be achieved by deployment of variable frequency drives (VFD) for motor-driven auxiliaries such as feed-water pumps and induced draught (ID) fans. Condenser optimisation measures may include simply cleaning deposits, reconfiguring the existing tubes, or complete condenser replacement. These and more solutions are described in an IEACCC report by Henderson (2013).

3.4.6 Focus on China: high temperature retrofits

The greatest efficiency gains for existing subcritical or supercritical plants can be obtained by significantly raising the steam temperature of the unit. Such an approach has been recently demonstrated in China. It is described in detail here as China is an example of a country where the energy sector has undergone a rapid transformation to significantly increase the efficiency of the coal fleet and lower its emissions within a relatively short time. The average coal fleet efficiency increased by a total of 7.57 percentage points between 2003 and 2018, as a result of a series of supportive policies and investment in technological solutions (Zhu, 2020a).

In China, there are about 880 subcritical units of 300 MW and about 140 subcritical units of 600 MW amounting to 350 GW, which account for about a third of the total capacity (Feng and Li, 2019). As these units have an average service life of less than 20 years and are quite flexible due to their size and technical features, shutting them all down has been ruled out as a waste of investment and resources. Instead, it has been decided to increase their efficiency to the levels set in the Action Plan on Upgrade and Reconstruction outlined in 2014. Figure 14 shows the actual and required efficiency for subcritical units, with that required in the Action Plan for 300 and 600 MW units given in the first two columns. The other columns show the actual efficiencies found for 1000 MW, 600 and 300 MW units.

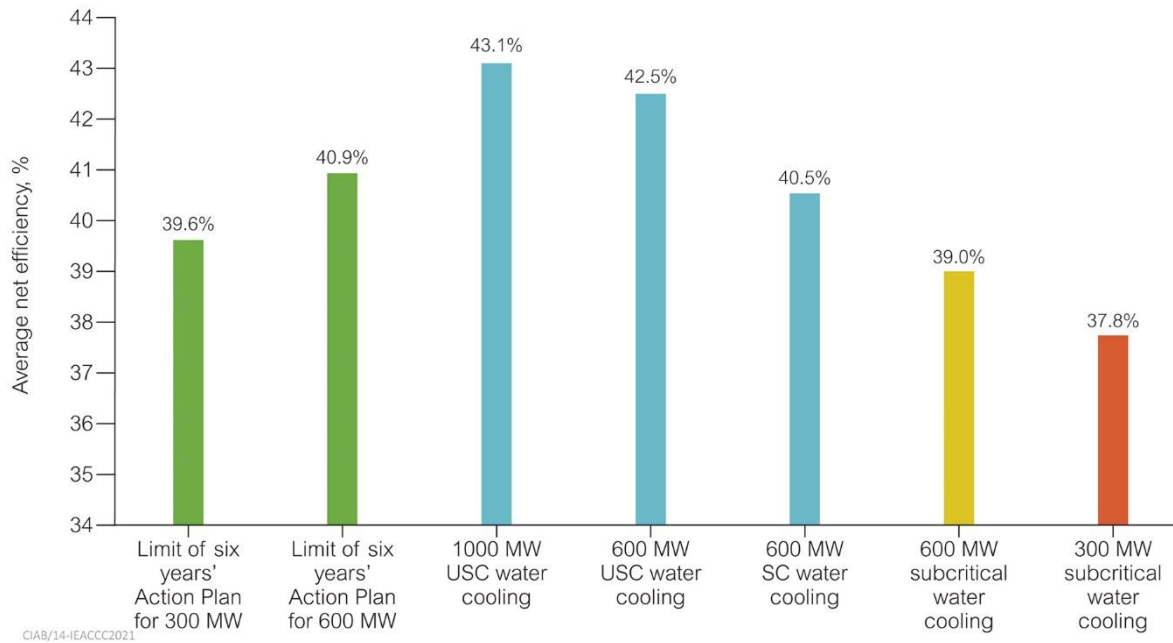


Figure 14 The efficiency requirements set by China’s Six Years’ Action Plan compared with the actual efficiencies of various coal-fired unit types (Feng and Li, 2019)

The Action Plan requires the 300 MW units to increase their efficiency from around 37% or less to 39.6%. Cost-benefit analyses were carried out on several options to establish the best way to achieve the efficiency increase. The options examined included modification of the turbine path, upgrading to double reheat, increasing the main and reheat steam temperature to 566°C, and increasing steam temperature to 600°C. A comparison of the costs and benefits of these retrofit options is shown in Table 7. This analysis illustrates that increasing the steam temperature to 600°C, while retaining the existing pressure, allows the greatest increase in efficiency while keeping costs at an acceptable level.

TABLE 7 COMPARISON OF COSTS AND BENEFITS OF SOME RETROFIT OPTIONS FOR SUBCRITICAL UNITS (FENG AND LI, 2019)

Items compared	Typical modification of turbine flow paths	Upgrade to double reheat	Slight increase of temperature to 566°C	High temperature retrofit (600°C)
Expected UNE under rated condition	About 39.6%, 2.4% lower than needed	About 41.6%, 0.4% lower than needed	About 40.3%, 1.7% lower than needed	>42.3% (Xuzhou project >42.8%)
Efficiency improvement	1.2%, usually declines over time	3.2%	1.9%	>4%
Cost per unit (in China)	US\$8 million	More than US\$123 million	US\$36 million	US\$47 million
Cost/benefit	≈US\$10 million per 1% UNE	>US\$38 million per 1% UNE	US\$19 million per 1% UNE	<US\$12 million per 1% UNE
UNE = unit net efficiency				

Unit 3 of China Resources Power Xuzhou Company Ltd in Xuzhou, which has a capacity of 320 MW was chosen to demonstrate increasing the steam temperature from 538°C to 600°C. Commissioned in 2004, the unit is relatively young. It has a two-pass drum boiler manufactured by Dongfang Boiler and a turbine made by Shanghai Turbine. Although it had undergone high pressure-intermediate pressure turbine flow path modifications in 2012, the turbine efficiency under turbine heat acceptance (THA) conditions declined by 2016 to about 38.6%. The aim of the retrofit project, started in 2017, was to keep the same turbine back pressure but achieve an efficiency of 42.8% (LHV) – a level that surpasses all SC units and some early USC units (Li, 2020).

Retrofit of the boiler concentrated on the heating surfaces: mainly reheaters and radiation superheaters, but pipes were also retrofitted. Austenitic steels Super 304H and Sanicro 25 were used for superheater tubes. A special start-up system was developed so that the boiler can be preheated without firing the oil burners, which saves oil and power. In addition, the new start-up system can effectively prevent the overheating of boiler tubes and therefore prevent oxide exfoliation and solid particle erosion problems in the turbine (Li, 2020).

High pressure and intermediate pressure turbines were retrofitted with a new rotor and blades. All sealings, inlet valves and the inner high pressure and intermediate pressure turbine casings were replaced too. Additionally, the low pressure casing exhaust area was optimised. The turbine remained in its governing stage, and the boiler drum also remained. This was to enhance the flexibility of the unit (Feng and Li, 2019).

Apart from the turbine and boiler retrofit some of the energy-saving solutions known as Feng's 5E technologies (Energy saving, Efficiency preservation, Environmental protection, Ensuring safety, and Elevated turbine-generator) were applied. These included the flue gas heat recovery system and generalised regeneration technologies which were developed at Waigaoqiao unit 3 and which aim to

reduce the heat loss within the power plant, including the use of the turbine exhaust for feedwater heating (Feng and Li, 2019).

The retrofit of the unit was completed in 2019, after which a 168 hour trial operation was carried out by Siemens and GE. It showed that the net efficiency under the rated load was around 43.5%, which was higher than the guaranteed 42.8%. This corresponds to 281.8 g/kWh coal consumption and about 94% boiler efficiency, while the efficiency at 50% load was just over 40% (see Table 8).

Unit load, %	100		75		50	
Boiler efficiency, %	94.32	94.07	93.92	93.95	93.34	93.25
Turbine heat rate, kJ/kWh	7463.3	7456.5	7573.6	7540.3	7886.6	7887.5
Total unit power, MW	320.8	319.6	233.1	243.0	160.7	162.4
Auxiliary power, MW	13.9	13.8	11.5	11.8	9.5	9.4
Net unit power, MW	307.0	305.8	221.6	231.3	151.1	153.1
Net coal consumption, g/kWh	281.8	282.1	288.7	287.0	304.6	304.3
Net efficiency, %	43.59	43.54	42.55	42.79	40.32	40.36

Additional tests showed that the unit can operate safely with the minimum load just under 20% and is much more flexible while maintaining low emission levels (Li, 2020).

There are plans to apply these solutions to the remaining subcritical units to improve fleet efficiency (Li, 2020). A similar approach may be applicable to some of the younger subcritical units in India. Subcritical units are the most likely to be cycled to balance increasing solar and wind generation. Hence keeping the subcritical units, but raising their operating temperature while maintaining the pressure and keeping the boiler drum will facilitate their flexibility and ensure lower emission factors. However, the suitability of any solution needs to be assessed on a plant by plant basis.

3.5 BEYOND STATE-OF-THE-ART EFFICIENCIES

3.5.1 Advanced ultrasupercritical power plant

Although there are numerous ways to increase the design efficiency of a coal plant, the greatest results are achieved by increasing the temperature and pressure of the steam cycle, known as the steam parameters. State-of-the-art plants currently use steam at 600°C to 620°C, but pushing beyond these temperatures has occupied researchers for almost two decades. A massive increase in steam temperature to 700°C (760°C in the USA) is targeted to create advanced ultrasupercritical (AUSC) power plants, and R&D programmes on this topic are ongoing in China, India, Japan and the USA and to a lesser extent in Europe. However, despite intensive research around the world since the late 1990s, the first AUSC plant is yet to be built. There are various reasons for this. Some are technical – to push steam parameters higher requires new materials such as nickel (Ni)-based superalloys for the

hottest areas of the plant and improved steels for less demanding ones. These are expensive, need to be fabricated in new ways and tested before they can be used in a commercial plant. Other reasons include a lack of relevant government policies and funding.

Like China, the EU, Japan, and the USA, India has an R&D programme on AUSC plant. The main objective of the project is to establish indigenous AUSC technology including the design and demonstration of an 800 MW AUSC plant with 710°C main steam and 720°C reheat temperature, 31 MPa pressure, and an efficiency of 46% (HHV, gross) (Kumar and Chetal, 2019). The plant is supposed to fire Indian coal with a gross calorific value (GCV) of 3700 kcal/kg (15,481 kJ/kg) (Pande and Dahiya, 2019). Although the Indian programme is relatively young, it is using the wealth of experience from other R&D initiatives. Many activities, including operating component test facilities and work on water chemistry protocols, are underway. If these are successful, and India remains committed to developing AUSC technology, it may commission the first plant within a decade (Pande and Dahiya, 2019).

3.5.2 Double reheat

Deploying a double reheat steam cycle, which is well-proven technology and in use since the late 1950s, is another way to increase coal plant efficiency to around 50%. Although double reheat units fell out of favour in the 1970s, mainly due to the introduction of nuclear power, combined cycle gas turbines, and persistently low oil prices, they are experiencing a revival in China, where more than 12 units of 600 MW or more have been built in the last decade.

An excellent example of double reheat deployment is the 415 MW Nordjylland unit 3 in Denmark, which was commissioned in 1998 and remains one of the most efficient coal units in the world, achieving 47.2% (LHV) efficiency. The unit operates with a steam temperature of 582°C/580°C/580°C and 29 MPa pressure and can run in either of the two modes: power only or combined heat and power (CHP). The combination of low temperature seawater cooling (10°C), high superheat steam (580°C) and double reheat contributes to its excellent performance. Additionally, the unit can operate with 20% low load, meaning it can serve as back up to intermittent renewable sources. At 415 MW, almost half the size of the largest German and Japanese units at the time, such high efficiency proves that increasing unit size is not essential for increased electrical efficiency.

Double reheat requires an additional intermediate pressure turbine and additional main and reheat steam pipes. In order to reduce the cost of piping and minimise pressure drop and heat loss, novel turbine configurations with reduced pipe length are being developed in China. These include elevating the high pressure and intermediate pressure turbines to the level of the boiler reheater outlet, as in the 1350 MW Pingshan Phase 2 unit (currently under construction), where the efficiency is expected to reach 49.6% (LHV). In the similar 660 MW Fuyang 2 project, the whole turbine train will be elevated. This project is also under construction and expected to surpass the design efficiency of Pingshan Phase 2.

Application of advanced Ni-alloys in double reheat units is under consideration by the Japanese and Chinese R&D programmes and has the potential to increase efficiency to 54% or more.

Besides efficiency gains, use of a double reheat steam cycle may also prevent low pressure turbine blade erosion (Kjaer, 2020). Some single reheat cycles have low condenser pressure which gives rise to relatively high moisture content, or wetness, in the low pressure turbine. This moisture can cause severe erosion, particularly to the low pressure turbine blades (Kjaer, 2020). Double reheat reduces the steam moisture content by almost 50% compared with single reheat. Hence double reheat units experience less erosion in the low pressure turbine (Kjaer, 2020). Also, as the moisture content is so low, the steam extracted for feedwater preheating can be increased to an optimum level, as noted by Nicol (2015).

Double reheat plants, the innovative Master Cycle and novel configurations are reviewed in depth in the recent IEA CCC report (in draft) by Wiatros-Motyka (2020).

3.6 MAXIMISING COAL PLANT FLEXIBILITY

As discussed in Chapter 2, India has an ambitious goal to integrate around 100 GW of solar and 60 GW of wind into its electricity grid by 2022. As solar and wind are intermittent sources, they require back up from thermal plants. Hence to balance generation from VRE, coal plants have to adapt to new operating regimes, and units which were built to run predominantly as baseload must operate at off-design conditions. This requires new skills, new or improved operation and maintenance strategies and in many cases, modern equipment and some investment.

There is no ‘one-size-fits-all’ solution to make a coal-fired power plant flexible. This is because the flexibility requirements vary between different power plants, depending on grid characteristics, electricity market design and cost factors. For some, achieving low minimum load is important while, for others, it is about fast start-up and rapid load ramp rates and load following. All this is known as plant cycling.

Flexible plant operation can have a significant impact on all areas of a coal-fired power plant due to the increase in thermal and mechanical fatigue stresses in various parts which, together with other effects, often occurring in synergy, reduce the lifetime of many components. Unit heat rate reduction is another detrimental effect, along with higher auxiliary power consumption and corresponding specific CO₂ emissions. Additionally, when there is a high penetration of VRE to the electricity grid, the operating costs for fossil fuel-fired plants can increase by 2–5% on average.

The flexibility of existing power plants can be improved in various ways, including: retrofitting new technologies, modifying existing, or adopting new, operating procedures and staff training. Usually, improvements start with upgrading the instrumentation and control systems as they behave differently during full load and part load operation. These upgrades improve accuracy, reliability and speed of control, and, as the most cost-effective way to increase plant flexibility, should be a

precondition for other measures. However, for older power plants with a limited remaining service life, it may not be viable to retrofit new systems, so their flexibility can be improved by plant management strategies.

One flexibility requirement is the ability of a power plant to operate at low minimum load (the lowest possible load without the use of supporting fuel), as this can minimise the number of shut-downs required, which in turn reduces the impact on plant component life and lowers operating costs. A minimum load of only 10–15% with various measures implemented, has been demonstrated by some plants in Germany. A minimum load of around 20% has been achieved in other countries including China. Ensuring stable combustion is key to achieving low minimum load. It requires the deployment of measures including optimisation of coal fineness and air/fuel flow; indirect firing; changing the size and number of mills; and reliable flame monitoring.

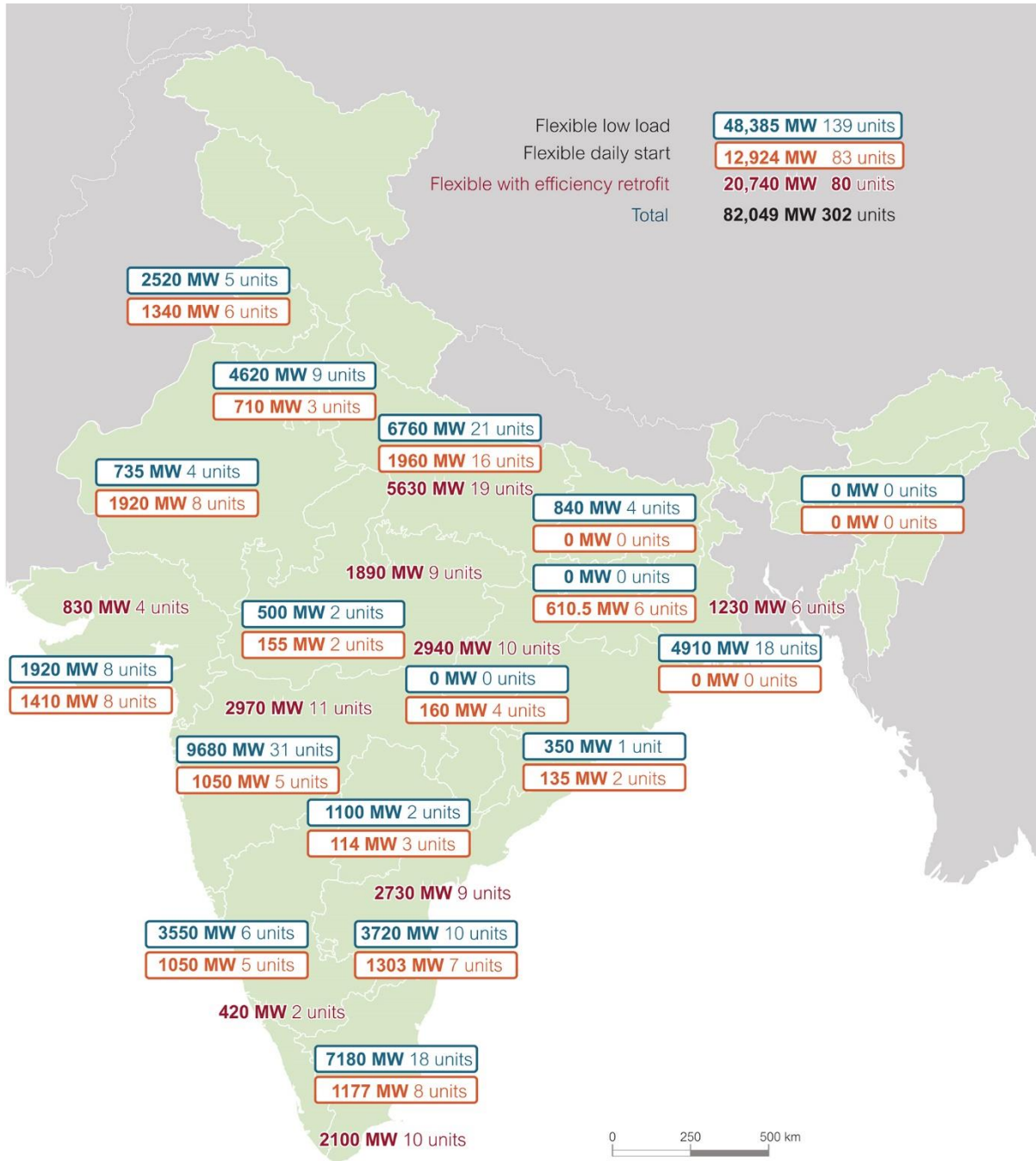
Start-up procedures are complex and expensive as they usually require auxiliary fuel during ignition of the burners. Shortening start-up time and the ability to ramp up rapidly ensure a quick response to changes in market conditions. This can be achieved by several measures including: reliable ignition, integration of a gas turbine, reducing the diameter of thick wall boiler components such as headers, or including more headers, cleaning deposits from the boiler and turbine, advanced sealings, turbine bypass and internal cooling. Many of these improvements aid high ramp up rates. Other measures include exploring mill storage capacity, condensate throttling, and the use of an additional turbine valve.

The performance of emission controls can also be affected by flexible operation, mainly due to the temperature of the flue gas which changes with the cycling regime. Hence it must be maintained at the required level, particularly for NO_x controls. This can be achieved in several ways. For example, by using an additional heater for the flue gas prior to the selective catalytic reduction (SCR) inlet. In selective non-catalytic reduction (SNCR), the use of multiple zones of injection and the ability to take injectors in and out of service as needed, ensures the required performance. For flue gas desulphurisation (FGD), the number of shut-downs and start-ups needs to be minimised to avoid slurry solidification and accumulation of start-up fuel oil residues on linings, as well as averting long warm-up periods. Particulate matter (PM) controls usually cope well with flexible operation conditions providing that the flue gas temperature does not fall below 90°C. A high proportion of on-load failures originate from preventable damage caused during off-load periods. The risks are higher for cycling units as frequent start-ups/shut-downs and standby periods disrupt the physical and chemical conditions within the water/steam circuit, leading to corrosion and other damage during standby. Thus, proper preservation of the all water-steam circuits is essential and can be achieved by various methods, which should be selected based on the power plant's individual characteristics.

In India, the low volatile, high ash coal impacts flame stability at low load so it will not be possible to achieve the same results as those obtained in Germany, for example. Recognising this, various analyses

have been carried out to manage the integration of wind and solar energy in India, and thus ensure the lowest possible curtailment of VRE.

It has been established that around 300 units, which equates to 82 GW of the coal fleet, will have to run in some kind of flexible mode (see Figure 15).



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Figure 15 Country-wide flexibility potential based on universal metrics (USAID GTG-RISE, 2020)

Consequently, several initiatives and international collaborations have formed and pilot tests have been conducted to establish the best solutions for power plants firing Indian high-ash coal. For example, under the USAID Greening the Grid - Renewable Integration and Sustainable Energy (USAID GTG-RISE) programme, which is a joint initiative of USAID and the Indian Ministry of Power, four pilot tests were conducted with the aim of setting a benchmark for other coal plants. One of the main outcomes was devising the appropriate procedures to run a plant with 40% minimum load and 3% ramp rates. Overall, the initiative resulted in establishing key recommendations for the following: load following operation; compensation for the capital expenditure (Capex) of installing the necessary equipment, as well as the operating expenditure (Opex) of running plant in a flexible mode; a fleet-wide strategy for implementation; and procedures for low load and high ramp rates. The tests have given confidence to some Indian utilities that plants firing high-ash coal can operate flexibly with a relatively low initial investment. However, as plants will cycle more, damage will increase, and it is important that appropriate policies and compensation mechanisms are in place. This remains a major concern for the utilities. All the findings from the four year trials and the recommendations made are summarised in a new (October 2020) publication: 'Transition towards flexible operation in India' by GTG-RISE (2020).

Additionally, the recently published 'The Recipe Book for Flexibilization of Coal Based Power Plants' by Sinha (2020b) considers the unique Indian conditions for power plant operation and is recommended to the interested reader. The book highlights O&M practices for flexible operation with safety, emission reductions, improvement in part load efficiency, reduced damage to equipment and cost reduction, all based on established techniques and best practices worldwide. Also, as noted by Sinha (2020b), the book was prepared based on the experience gained from a series of pilot studies, test runs and operational experience in Indian coal power stations as well as a survey of power plant operators and data collected from more than 24 coal-based power stations in India.

Useful tools have been developed to help generators prepare their plants for flexible operation. For example, GE has developed an AIM – Asset Insights and Merit Management tool, which allows plant owners to match the performance of the best plants in their class and prepare for future flexibility challenges. The AIM tool analyses the main areas of plant operation such as boiler efficiency, turbine heat rate, unit gross efficiency and variable costs, compares them with the best plant in the class, and suggests areas on which to focus optimisation, as well as providing estimated cost savings for suggested improvements. Figure 16 shows an example of the AIM tool – dashboard results (Kendhe, 2020).

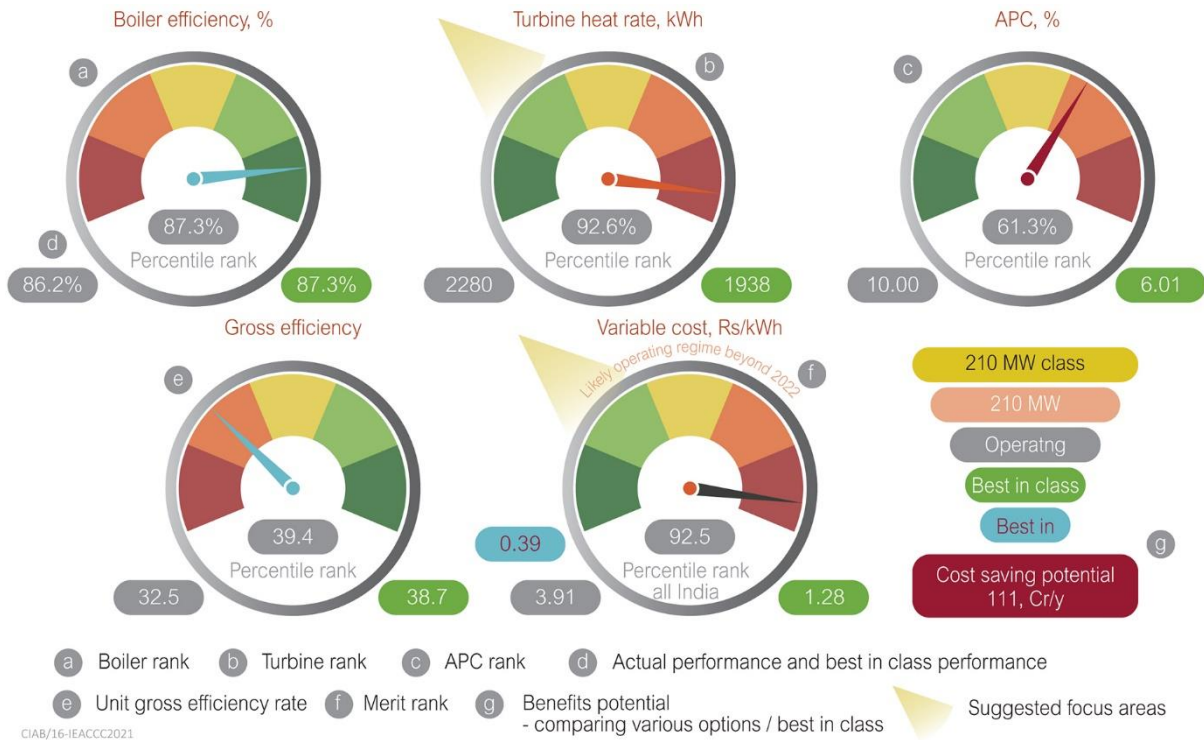


Figure 16 GE AIM tool – dashboard results explained (Kendhe, 2020)

Another useful tool is the recently launched ‘High level flexibility assessment and benchmarking tool’ from EPRI, which was developed in collaboration with NTPC. The tool allows utilities to assess their assets and asset management practices with the aim of helping mitigate potentially costly equipment damage and to promote safe, efficient and event-free operations. It has integrated templates that provide an assessment process for identifying gaps in flexibility performance. These templates allow assessment of the following:

- equipment operating modes;
- pressure part management;
- operations;
- maintenance;
- combustion and boiler performance;
- instrumentation, controls and automation;
- environmental controls;
- cycle chemistry;
- turbine/generator; and
- balance of plant.

Completing such assessments will facilitate management of the flexible operation of the power plant (EPRI, 2020).

More detail on different flexibility initiatives in India and worldwide solutions for power plant flexible operation can be found in several publications including an IEACCC report by Wiatros-Motyka (2019) and the VGB toolbox for flexible plant operation (VGB, 2018).

Financial incentives for flexible plant

Operating coal power plant more flexibly presents some significant economic challenges to generating companies. As noted, there is likely to be accelerated deterioration of components in cycling units, as well as an impact on average efficiency and increased consumption of start-up fuel. Most significantly, plants with lower operating hours will face reduced revenues and potential shortfalls in recovery of fixed and variable costs. Some strategies for compensating operators of flexible plant are set out by the GTG-RISE programme, applicable within the structure of India's regulated tariff system, such as the addition of increased O&M costs to the tariff for operation below a specified load (Sinha and Sinha, 2020).

As India moves towards a more competitive power market, the value of flexible operation will be increasingly represented in the market price of power, which will rise in times of scarcity. However, experience in liberalised power markets with high renewable penetration (chiefly in the USA and Western Europe) has shown that the value of thermal plants to the grid is usually still insufficiently expressed in wholesale power prices, resulting in generators struggling to achieve financial viability. In particular, there are often weak signals to invest in new generating capacity. For this reason, several markets in the USA, Europe, and Japan, have implemented forms of capacity market, in which generating units are awarded fixed payments for their availability during periods of peak demand. These capacity contracts are usually awarded through an auction process, based on an offered price per MW of available capacity. A 2015 report by the Indo-German Energy Programme outlined some steps for India to take prior to potential implementation of a capacity market, including linking the existing fixed charge to availability (rather than PLF) and further development of energy spot markets (Bose and others, 2015).

The value of flexible thermal plant to the grid can also be compensated through markets for ancillary services, such as frequency balancing, reactive power, and fast ramping products. In the last few years, CERC has begun to introduce compensation mechanisms for forms of frequency control, and this trend is expected to continue. A comprehensive review of ancillary service market developments in India and internationally can be found in the IEACCC report by Lockwood (2020a).

3.7 RECOMMENDATIONS

Improving the efficiency of India's huge and growing coal fleet will play a key role in lowering the country's CO₂ emissions while maintaining economic growth and reliable access to electricity. In the last decade India has already begun the transition to higher efficiency technologies through various policy measures, including more competitive tariff bidding, domestic development and promotion of SC, USC, and AUSC technologies, renovation and modernisation programmes for existing units, and

encouraging the retirement of ageing units. However, there is still considerable scope to accelerate this transition through more targeted policy action, including:

- Continue the transition towards economic-based merit-order dispatch in order to provide market incentives to more efficient, flexible units;
- Introduce a complementary mechanism to penalise less efficient units with competitive fuel costs, such as ‘first run’ status for the most efficient units, or a form of carbon pricing;
- For units that continue to operate under regulated ‘cost-plus’ tariffs, heat rate norms should be tightened according to global technology benchmarks;
- Tighten the efficiency saving targets required under the next cycle of the PAT scheme;
- Introduce efficiency standards to ensure that all new units must be SC as a minimum, and USC from 2025;
- Existing subcritical units must also be required to meet an efficiency standard based on levels technically achievable through upgrading, or encouraged to retire;
- Ease the regulatory process for retirement of inefficient units and replacement with new units;
- Encourage the adoption of digital tools to allow efficient operation of flexible plant, and develop mechanisms to compensate the accelerated degradation of these units;
- Further develop domestic capability with high-efficiency plant designs such as USC and AUSC; and
- Provide Government support for technical capacity building and international knowledge sharing in the manufacture and operation of high-efficiency, flexible units.

4 IMPROVING AIR QUALITY

Ambient air pollution is a serious risk to health in many countries, and can shorten lives, especially through cardiovascular diseases. India experiences some of the highest air pollution levels worldwide and consequent impacts on human health.

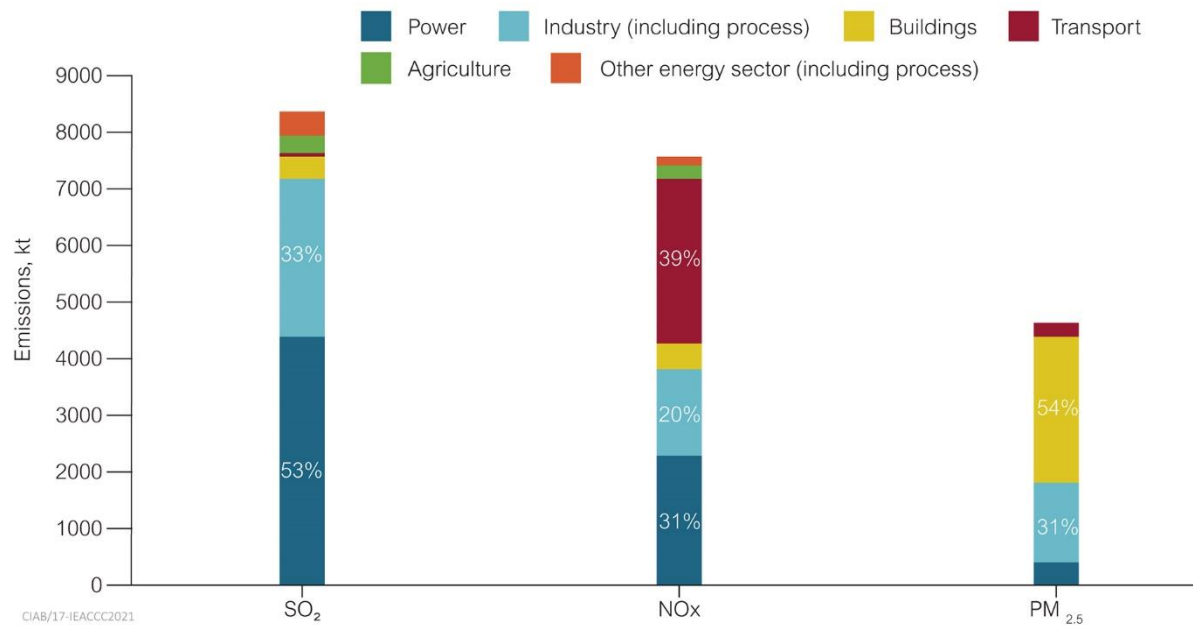


Figure 17 India's SO_x, NO_x, and PM_{2.5} emissions by source (IEA, 2019a)

In 2018, the power sector was responsible for 53% of India's SO₂ emissions, 31% of NO_x emissions and a small proportion of PM_{2.5} (see Figure 17) (IEA, 2019a). However, relevant control technologies for these pollutants have yet to be widely implemented, despite the introduction of emissions standards in 2015 (CSE, 2020b). Consequently, India has the potential to markedly improve the health and livelihoods of many of its citizens by prompt installation of pollution controls on its coal-fired plants.

4.1 AIR POLLUTION STANDARDS

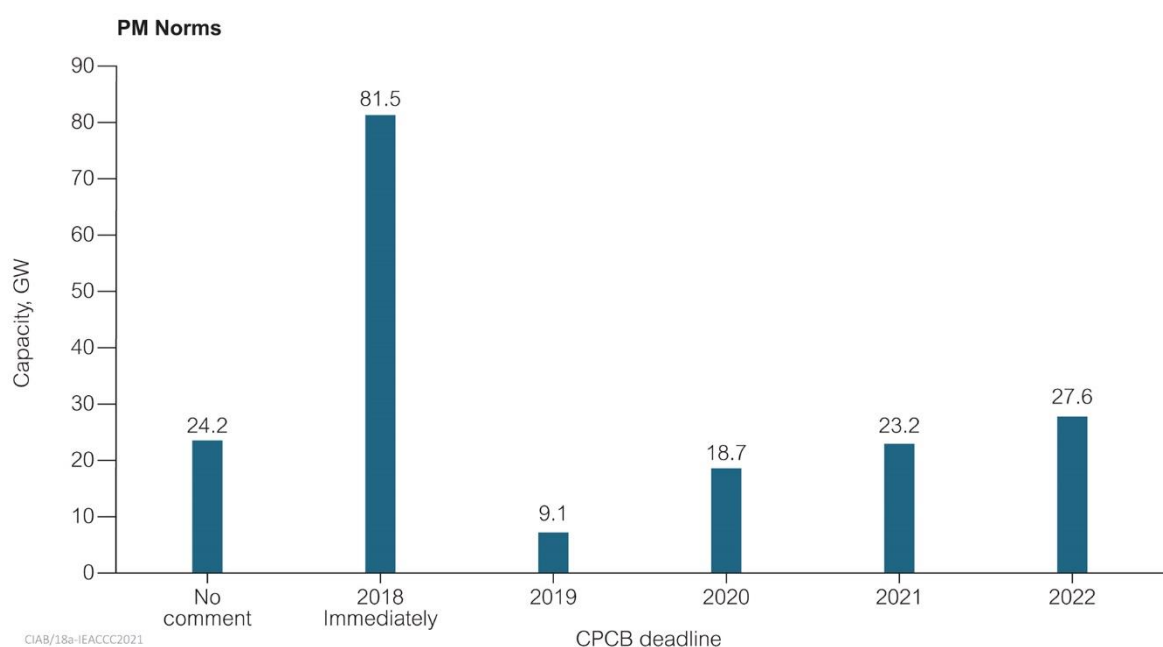
Since the 1970s various technologies to control emissions of nitrogen oxides (NO_x) and sulphur oxides (SO_x) have been used in countries with relevant emission standards. But in India, there were no limits for these pollutants until December 2015. Instead, National Ambient Air Quality Standards were in place, and minimum stack heights were specified to disperse emissions of SO₂ and NO_x. There were standards (or norms) for the control of particulate matter (PM) before 2015, but they were relatively lenient at 150 and 350 mg/m³ depending on the size and age of the plant. However, they resulted in most coal-fired plants having relevant PM controls in place (Sloss, 2015a; Nalbandian-Sugden, 2015).

The standards introduced in 2015 are similar to those in the EU and USA for existing plants, and relatively ambitious for new units. However, progress in installing the required pollution control technologies has been relatively slow. Since the announcement of the new norms, the initial 2017

deadline for implementing the technologies has been put back to 2022, although some plants have earlier deadlines, as shown in Figure 18 and some limits on NO_x emissions and water use have been relaxed.

Table 9 shows the current (October 2020) emission standards while Figure 18 shows the deadlines for PM, SO_x and NO_x for different plants issued by the Central Pollution Control Board (CPCB) in 2017.

TABLE 9 CURRENT EMISSION STANDARDS FOR COAL-FIRED POWER PLANTS IN INDIA					
	PM mg/m ³	SO ₂ mg/m ³	NO _x mg/m ³	Water mg/MW	Mercury mg/m ³
Old standard	150–350	None	None	None	None
2015 norms					
Units installed before 31 December 2003	100	600 (<500 MW) 200 (≥500 MW)	600	3.5	0.03
Units installed between 2004-16	50	600 (<500 MW) 200 (≥500 MW)	300 450*	3.5	0.03
Units installed from 1 January 2017	30	100	100	3.0	0.03
* Relaxed in 2020					



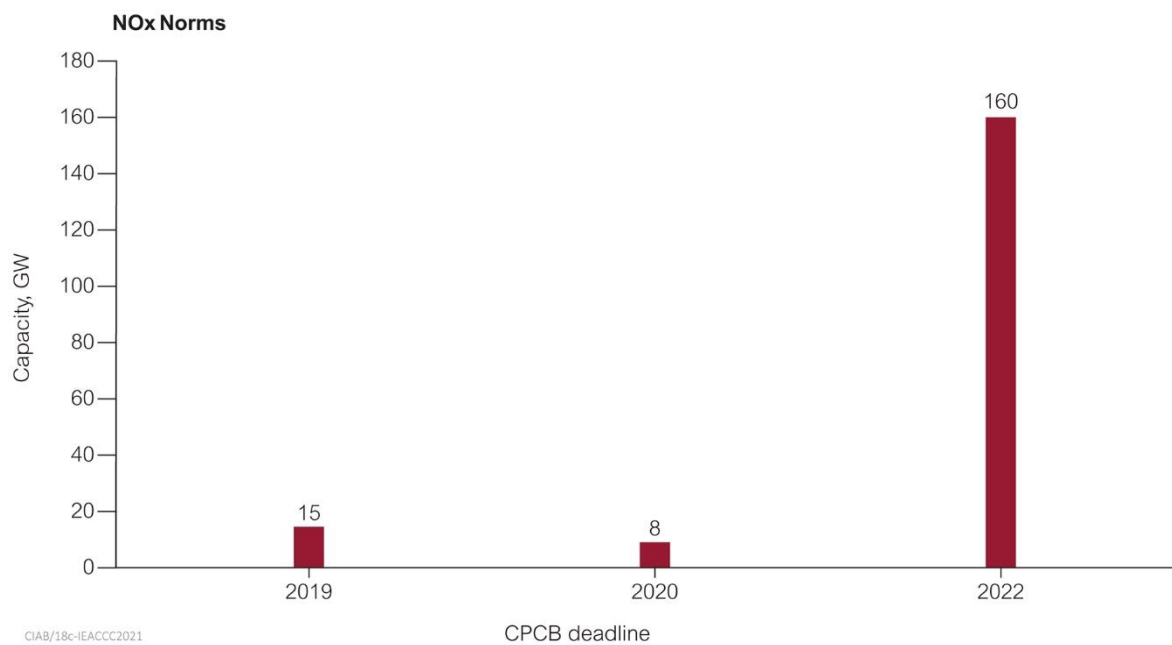
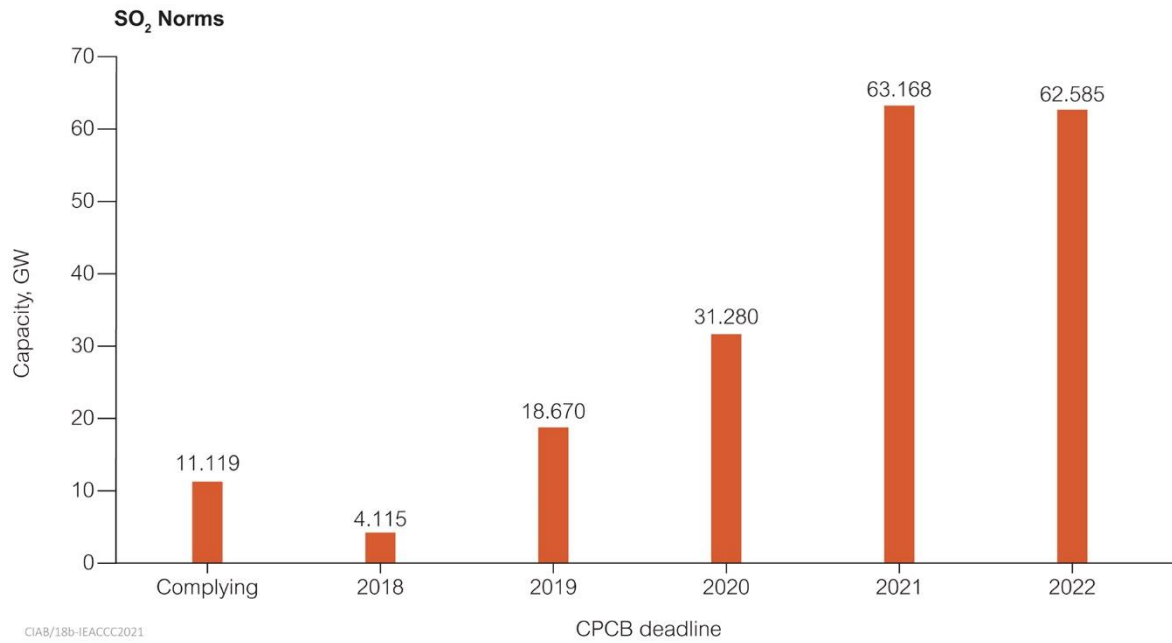


Figure 18 Deadlines for compliance with emission standards from CPCB (CSE, 2020b)

The next sections explore how the emissions standards can be met.

4.2 PARTICULATE MATTER

Due to the prior existence of norms for PM, most existing units already have PM controls in place, either in the form of electrostatic precipitators (ESP) and/or fabric filters or cyclones as shown in Figure 19.

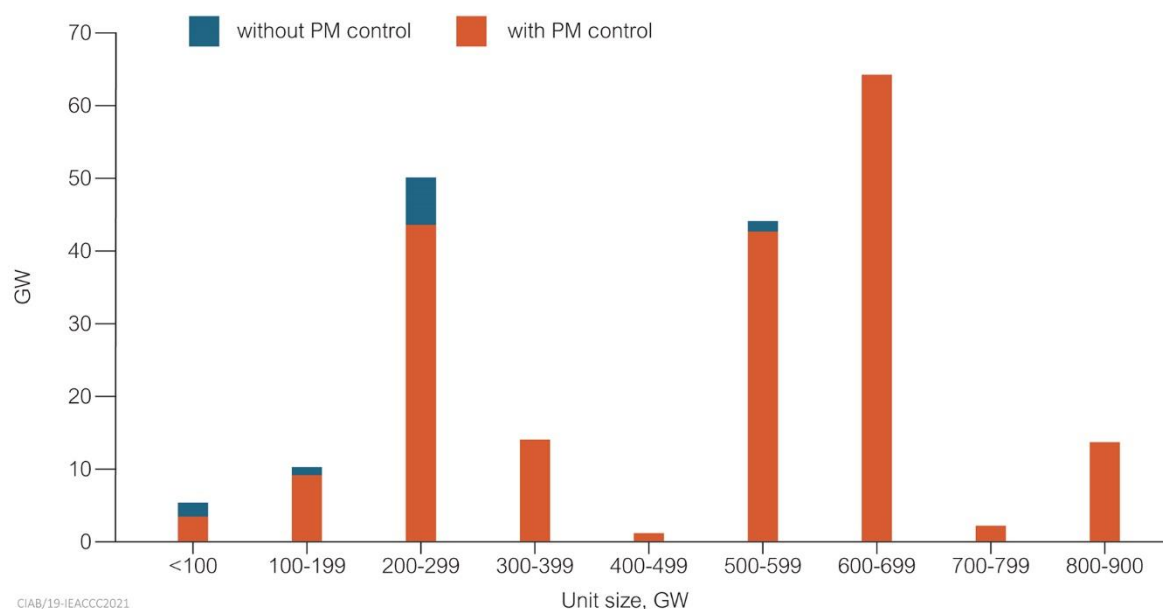


Figure 19 PM control fitted by unit size (total = 193 GW, utilities only as of March 2020) (adapted from S&P Global, 2020)

The Centre for Science and Environment (CSE) analysis from August 2020 shows that 56% of coal units already comply with the new norms for PM, but it is likely that this will only increase to 73% for the 2022 deadline (CSE, 2020b). Most units will only need to fine-tune or upgrade their ESP to comply with the new limits and the estimated cost for upgrading ESP is Rs 15–20 lakhs/MW (US\$20,000-27,000).

The problem with emissions of PM is two-fold:

1. particles are released to the atmosphere from the flue gas and cause adverse health effects in people; and
2. fly ash collected from ESPs and fabric filters has a low rate of utilisation and currently requires large tracts of land for disposal, while also leading to significant pollution to air, land and water.

The first problem can be solved easily by fine-tuning or upgrading existing PM controls and capturing more of the pollutant.

The problem of fly ash disposal and utilisation while currently serious, can also be resolved. Fly ash production from Indian coal power plants has increased with coal consumption, growing from 124 Mt/y in 2009-10 to 217 Mt/y in 2018-19 – an increase of almost 76%, as shown in Figure 20. The result is the accumulation of 1647 Mt of ash from coal combustion (as on 31 March 2019). Piles of ash in the wet form as slurry in ash ponds and in the dry form in open fields cause significant health and environmental risks which should be resolved promptly (Arora, 2020).

A recent report by CSE (Arora, 2020) on fly ash in India highlights the issue of ash management by power plants and recommends some policy measures, monitoring frameworks and practices to tackle the problem and clear the huge stockpiles of ash.

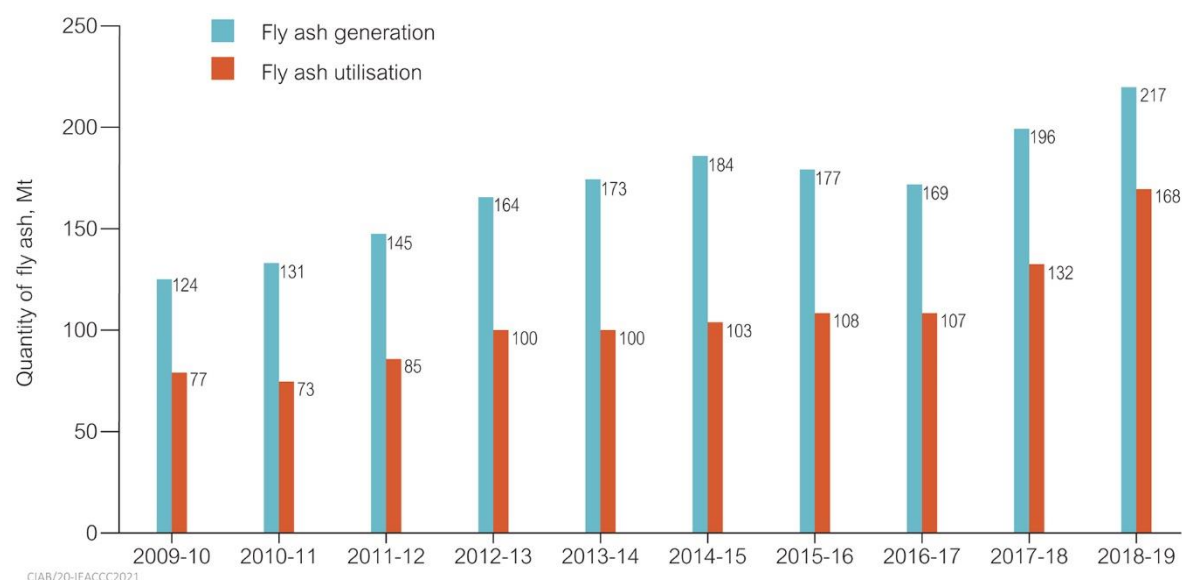


Figure 20 CSE analysis of fly ash generation versus utilisation (Arora, 2020)

There are many uses for coal fly ash (CFA) and it is now an internationally traded commodity. The dominant use of CFA is in the construction industry where it can substitute for cement clinker, replace cement in production of flowable fill and foamed concrete; and form low density manufactured aggregates, bricks, cement, and geopolymers. Rapid urbanisation in India is creating a huge increase in demand for construction materials and the production of cement is the largest industrial emitter of greenhouse gases globally. CFA substitution for cement is one way to reduce the environmental impact of the construction industry. Using 20% ash in cement reduces the energy requirement by 25%, and thus CO₂ emissions could also be reduced significantly. A proportion of CFA in concrete can also improve its construction properties.

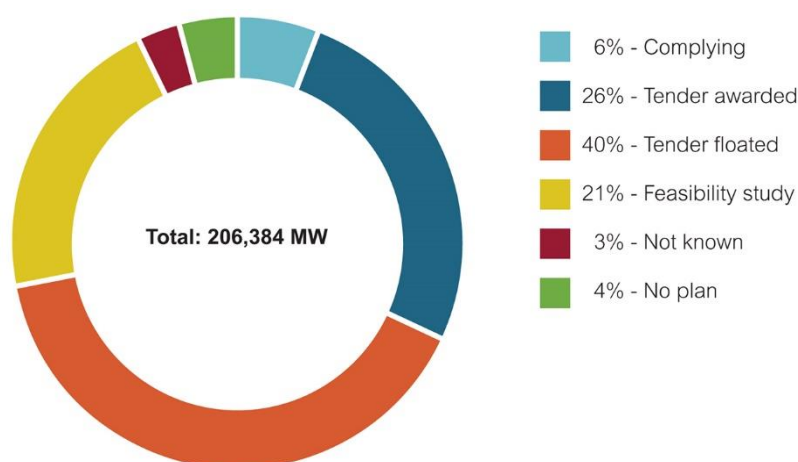
The Indian clay brick industry consists of about 100,000 kilns which operate 24 hours a day with associated emissions, consuming around 400 Mt of fertile clay soil each year. Substitution by CFA bricks would largely eliminate the pollution of this industry, allowing that some cement is needed. It would also preserve the agricultural land for feeding a growing population (Reid, 2020).

CFA can also be used in agriculture and as a source of rare earth elements (REE), which are critical materials for many new technologies. Uses for CFA are described in detail in an IEACCC report by Reid (2020).

4.3 SULPHUR DIOXIDE

Indian coal has a sulphur content in the range of 0.2–0.7 wt%, which equates to emissions of 800–1600 mg/m³ SO₂ if there are no controls in place. Thus, most plants must employ some form of

flue gas desulphurisation (FGD) to capture the SO₂ to comply with the new standards. Deadlines for compliance have been set by the CPCB for the bulk of the coal-fired capacity, totalling about 192 GW. Most of these plants will have to install wet limestone FGD which can limit SO₂ emissions by over 90%. As it takes up to two years to build and install this type of FGD, plants which have deadlines set for 2021-22 should have initiated construction in 2019. However, CSE analysis shows that most of these units are in the early stages of their compliance strategy – either carrying out feasibility studies (43 GW) or floating tenders (83 GW) (*see* Figure 21). Another 8 GW of units have no plans yet to install FGD and the status of compliance is not known for a further 6 GW. Combined, this constitutes 140 GW (70%) of capacity which is highly unlikely to meet the emission standard deadline of 2022, even if they awarded tenders now (late 2020) (*see* Figure 21) (CSE, 2020b). In addition, about 41 smaller units with a maximum capacity of 250 MW and generally more than 25 years old have no plans to implement controls.



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Figure 21 Compliance of the Indian coal fleet with SO_x norms, as of October 2019 (CSE, 2020c)

Of the 206 GW capacity which has to comply with the SO₂ norms, the centrally owned plants, notably those of NTPC, have a higher rate of implementation as about 68% of capacity (35.4 GW) has awarded tenders, and a further 26% capacity (13.6 GW) has floated tenders (as of June 2020) (CSE, 2020c).

The cost of installing wet limestone FGD in India is estimated to be Rs 50 lakhs/MW (68,000 US\$/MW). But some of this cost can be offset by the income to be gained from selling gypsum, a by-product of the process widely used in the construction sector. As only a handful of units in India currently operate wet FGD, gypsum prices from their operation are not well established. However, analysis by CSE indicates that it could be a significant source of revenue (*see* Table 10) (Trivedi, 2020).

TABLE 10 ANNUAL REVENUE FROM GYPSUM SALE FOR A 500 MW UNIT FITTED WITH FGD (TRIVEDI, 2020)

	Limestone consumed, t/y	Gypsum generated, t/y	Sold to cement	Sold for gypsum board manufacturing	Sold to other industries/ agriculture	Disposal, 25%	Revenues, Rs
Conservative estimates*	32,000	54,400	21,760 (40% of total)	10,800 (20% of total)	8,160 (15% of total)	136,000	2.61 crores
Optimistic estimates†	32,000	54,000		544,000 (100%)			5.44 crores

* Based on price from RSMML mines; † Considering 100% is sold to wallboard and plasterboard manufacturers

Dry or semi-dry sorbent injection has a SO₂ removal rate of 50–60% and is usually the chosen approach for older and smaller units.

Delays to the installation of SO_x control measures and compliance with the norms are now inevitable. It is recommended that meeting the SO₂ norms is not delayed further and appropriate mechanisms are devised by the government to encourage plants to invest in the technologies. Further, it is advised to keep the current norms country wide as both SO_x and NO_x can bond to particulate matter and travel hundreds of kilometres, affecting the health of people and the environment at large distances from the emission source. It is also important that the utilities can pass on, or recover, some of the cost of installation. Hence an appropriate financial framework is needed.

4.4 NITROGEN OXIDES

NO_x controls are well proven, mature technologies and used for many decades in Europe, Japan, and the USA and more recently in China. They are deployed widely both on hard coal and lignite which can have an ash content comparable to that of Indian coals. NO_x controls can be broadly divided into primary and secondary measures and are usually used in combination. Primary measures include:

- low NO_x burners (LNBS);
- air staging which includes the use of overfire air (OFA);
- fuel staging;
- low excess air;
- fuel biasing;
- recirculation of flue gases (FGR); and
- water or steam injection.

Secondary measures include:

- selective catalytic reduction (SCR);
- selective non-catalytic reduction (SNCR);
- a combination of both; and
- multipollutant control technologies (Wiatros-Motyka and Nalbandian-Sugden, 2018).

Of all the pollutant emission standards, the Indian energy sector perceives compliance with the one for NO_x as the most problematic. This is partly because of the limited experience of using NO_x controls in India, and concerns about the impact of high ash and low volatile coal on the controls. Recent experience with lower capacity factors in India has resulted in flame stability challenges which are exacerbated under low NO_x firing scenarios (primary measures). Other concerns relate to the potential challenges including the need to handle and store new reagents for secondary measures (ammonia or urea), the space required for retrofitting NO_x control technologies, the lack of local suppliers and the necessary skill set and a resulting need to import technologies, and of course, the associated costs.

Flexible operation of power plants is also seen as difficult for NO_x control as emissions can be a few hundred (100-300) mg/m³ higher during low load operation than when running as baseload. Also, coal quality can have an impact on NO_x emissions of 100–150 mg/m³ (Fortum eNext, 2020). Additionally, some NO_x controls (SCR and SNCR) operate in a specific temperature window. This means that it may be necessary to deploy additional means to keep flue gas at the required temperature, by using an economiser bypass, for example, for SCR and additional injection ports for SNCR (Wiatros-Motyka, 2019). However, evidence shows that although the ash content of Indian coal is challenging it has no impact on the majority of NO_x emission controls. Most units could achieve emissions of around 300 mg/m³ at all loads while deploying only primary controls, which are relatively inexpensive solutions.

Table 11 shows NO_x control technologies and their potential to reduce emissions versus the cost of installation. Although current prices, especially in India, may vary considerably from those given, the table illustrates the variation in cost between the technologies.

TABLE 11 NO _x REDUCTION TECHNOLOGIES: CAPABILITY VERSUS COST* (XU AND OTHERS, 2015)				
	Nominal NO _x reduction, %		Estimated installed cost, US\$/kW	
	Low	High	Low	High
Baseline	0		0	
LNB	30	50	5	10
OFA	20	45	5	10
Reburn	15	30	5	10
FGR	10	20	3	5
SNCR	25	50	10	20
LNB + OFA	44	73	10	20
LNB + FGR	37	60	8	15
LNB + SNCR	48	75	15	30
LNB + OFA + FGR	50	78	13	25
LNB + OFA + reburn	52	81	15	30
LNB + OFA + SNCR	58	86	20	40
LNB + OFA + FGR + SNCR	62	89	23	45
LNB + OFA +Reburn + SNCR	64	90	25	50
SCR	80	90	100 (32)*	200 (40)*

* The price in brackets is for SCR for Indian utilities based on CSE (2016)

Figure 22 shows the amount of NO_x emissions controlled depending on the technology, and in relation to the evolving EU environmental regulations.

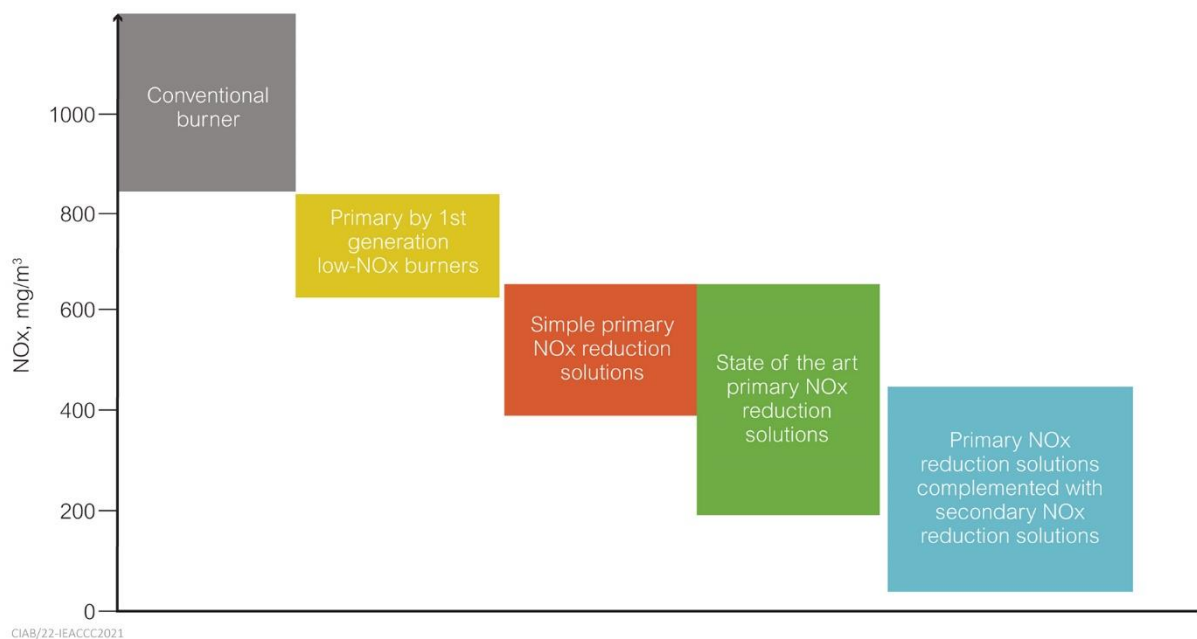


Figure 22 NO_x reduction levels depending on NO_x control technologies and in relation to the evolving environmental regulations in EU (Fortum eNext, nd)

There are three types of NO_x formation during coal combustion: fuel, thermal and prompt NO_x (see Figure 23 and Table 12). The fuel NO_x is the most important as nitrogen in coal is the source of approximately 80% of the total NO_x formed during coal combustion. This is assuming low NO_x combustion with furnace temperatures below the thermal NO_x formation thresholds (Storm, 2020).

However, the mechanisms of fuel NO_x formation are not currently fully understood. What is known, though, is that during a normal combustion process, only 20–30% of the fuel nitrogen content is converted to NO_x. The conversion of fuel nitrogen is weakly temperature-dependent but depends strongly on local burner stoichiometry (Innovative Combustion Technologies, nd). Therefore, fuel NO_x formation can be reduced by controlling the mixing of fuel and air and the availability of oxygen (Fortum eNext, nd).

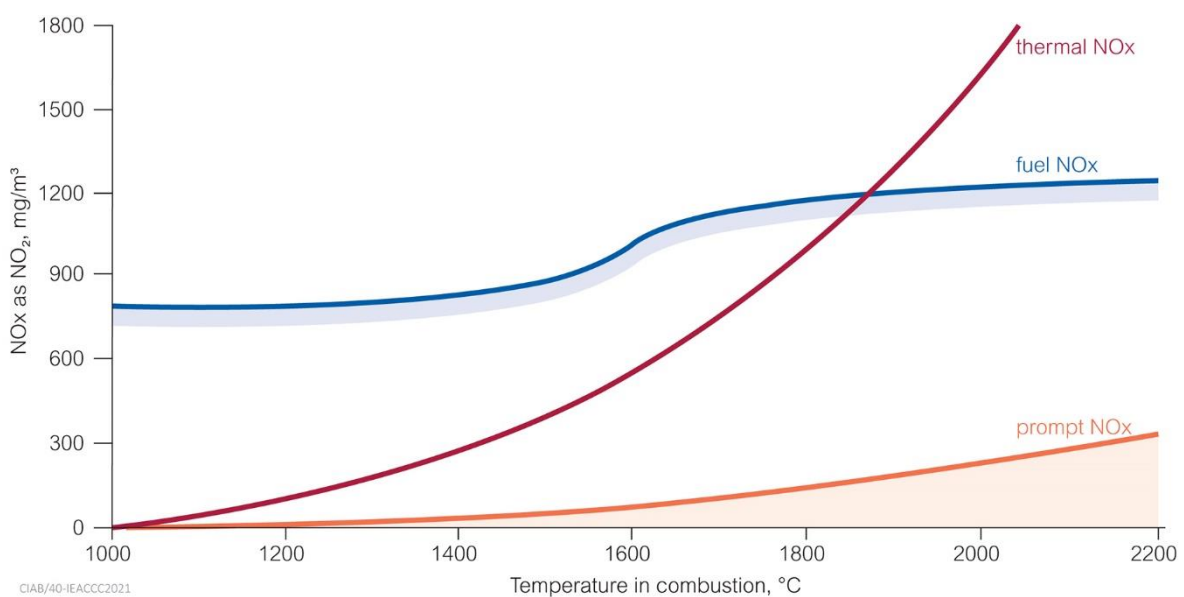


Figure 23 Influence of combustion temperature on the amount of NO_x produced from the three NO_x formation mechanisms (OECD, 1993)

TABLE 12 TYPES OF NO _x FORMATION DURING COAL COMBUSTION (FORTUM eNEXT, ND)		
Fuel NO _x	Thermal NO _x	Prompt NO _x
Oxidation of nitrogen contained in the fuel	Oxidation of nitrogen in the air through a direct reaction with oxygen	Oxidation of nitrogen in the air through reactions with hydrocarbons contained in the fuel
The dominant mechanism of NO _x formation in a boiler fired with pulverised coal	Less important in big furnaces	Typically not important in the combustion of pulverised coal
Can be reduced by controlling the mixing of fuel and air (flame stoichiometry, availability of oxygen)	Can be reduced by controlling the peak temperatures in the furnace	

The level of NO_x reduction achieved by primary measures depends on several factors, including:

- coal properties;
- coal fineness;
- air/fuel ratio and distribution to each burner;
- all air flows (primary, secondary, tertiary, OFA);
- burner level and mills in use (difference in NO_x levels when using top- or low-level burners is typically in the range of 100 mg/m³);
- boiler load (the difference between baseload and part load might be several hundred mg/m³);
- boiler dimensions and geometry (there must be sufficient space between burners and OFA so the complete combustion of coal can take place); and
- bulk furnace temperature, which can vary with boiler cleanliness and/or load (Holappa, 2020b; Fortum eNext, nd; Storm, 2020).

The properties of coal most relevant for primary measures are the nitrogen content and fixed carbon to volatile matter ratio (fuel ratio, FR), whereas the ash content and calorific value of the coal are less important. However, although the fuel ratio and nitrogen have a strong influence on NO_x formation, they should be considered together with the other factors listed (including air/fuel ratio, boiler geometry and the possibility of controlling oxygen levels in the boiler).

Analysis by Fortum eNext of more than 70 coals (domestic and imported) used for power generation in India showed that the nitrogen content varies between 0.55–1.98% and FR from 1.04 to 3.14. The following guidelines could be used to make ‘quick and dirty’ checks to assess if coals with the following properties can meet the NO_x emission levels of 300 mg/m³ using primary controls alone:

- If FR is <1.5 and the fuel nitrogen content is <1.5% then 300 mg/m³ should be possible using only primary controls;
- If FR is >2, a 300 mg/m³ emission limit may still be possible in cases where the fuel nitrogen content is very small (<0.6%);
- If the nitrogen content is >1.5%, a 300 mg/m³ emission limit may still be possible if the FR is <1.5; and
- If FR >1.5 is in combination with N >1.5%, then reducing NO_x emissions below 300mg/m³ may be difficult using only primary measures.

Some companies in India use the following correction factors regarding the influence of FR and nitrogen on NO_x levels:

- Every 0.1 change in FR changes NO_x emissions by 26 mg/m³; and
- Every 0.1% (abs) change in nitrogen content changes NO_x emissions by 12 mg/m³.

However, it is worth noting that correction factors based on FR and fuel nitrogen content do not take into account other influencing factors and might lead to unrealistic outcomes. Further, many power plants in India blend coals to achieve a higher calorific value. This means that the properties of an individual coal should not be taken as a definite indication of what can be achieved, but NO_x targets could be taken into account when coal blending in addition to current blending criteria (Holappa, 2020b).

4.4.1 Achieving NO_x emissions of 200–300 mg/m³ with advanced primary measures

Key combustion parameters such as the boiler efficiency, NO_x, oxygen, carbon monoxide (CO), loss on ignition (LOI) or carbon in ash (CIA) and furnace exit gas temperature (FEGT) depend strongly on the air/fuel ratio (see Figure 24). Thus, optimum combustion within a boiler with lower emissions of NO_x can be achieved by careful control of the fuel and air to the individual burners.

As noted in Chapter 3, maintaining the correct air/fuel ratio can also increase plant efficiency by up to 1–2% and can be achieved by the use of accurate, ideally digital, measurements of the coal and air flows. Such instruments can cost up to €1 million (Rs 8.7 crores) for both coal and air but the saving on coal combusted means that the payback time is often less than 1 year.

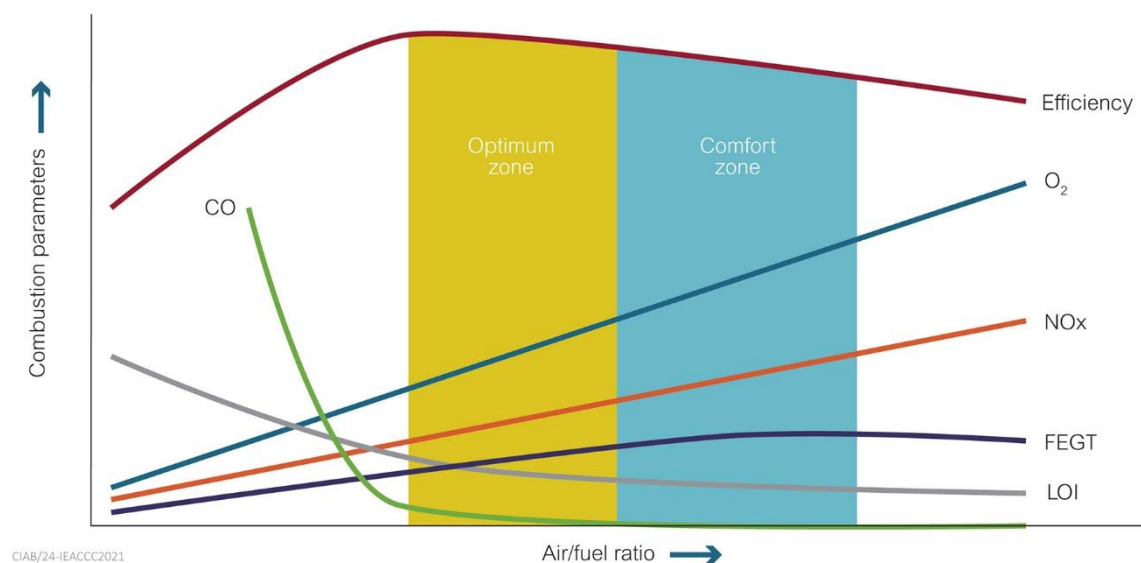


Figure 24 The variation of key combustion parameters with air/fuel ratio (Widmer and Marquez, 2012)

The air/fuel ratio is also dependent on various other factors including mill performance and coal fineness, and the geometry of the pipes to the burners. Extensive detail on optimising combustion, mill performance, fuel fineness, coal flow and air flow measurements and how they influence NO_x emissions and control can be found in the Appendix at the end of this report.

Investing in the latest primary controls makes financial sense

In countries where more stringent NO_x emission regulations have been introduced over time it has been standard practice to start with primary measures such as LNBS and OFA and then add an SCR or

SNCR or a combination of both. For new units, primary and secondary NOx controls are installed in combination from the beginning. Investing in the latest primary NOx controls lowers emissions further and also ensures minimum Capex and Opex spend on secondary technologies. This is because the reduction of every 100 mg/m³ of NOx comes with an operating cost, so if less NOx is left to be removed the plant will have a lower Opex. For example, units which choose older, basic NOx controls and then add SNCR to achieve emissions of 300 mg/m³ will have to spend around 4 million €/y (Rs 34.8 crores) on the reagent (see Figure 25). However, a typical 500 MW unit using SCR spends a total of 1–2 million €/y (Rs 8.7–17.4 crores) on ammonia (average <€0.5 million, Rs 4.3 crores) and changing the catalyst (average 1 million €/y, Rs 7.7 crores). So the units which use the latest primary NOx controls and SCR will consume less ammonia and need fewer layers of catalyst and can thus save around 1.5 million €/y (Rs 13 crores) (on Opex compared with the units which have basic primary NOx controls (see Figure 26) (Holappa, 2020a).

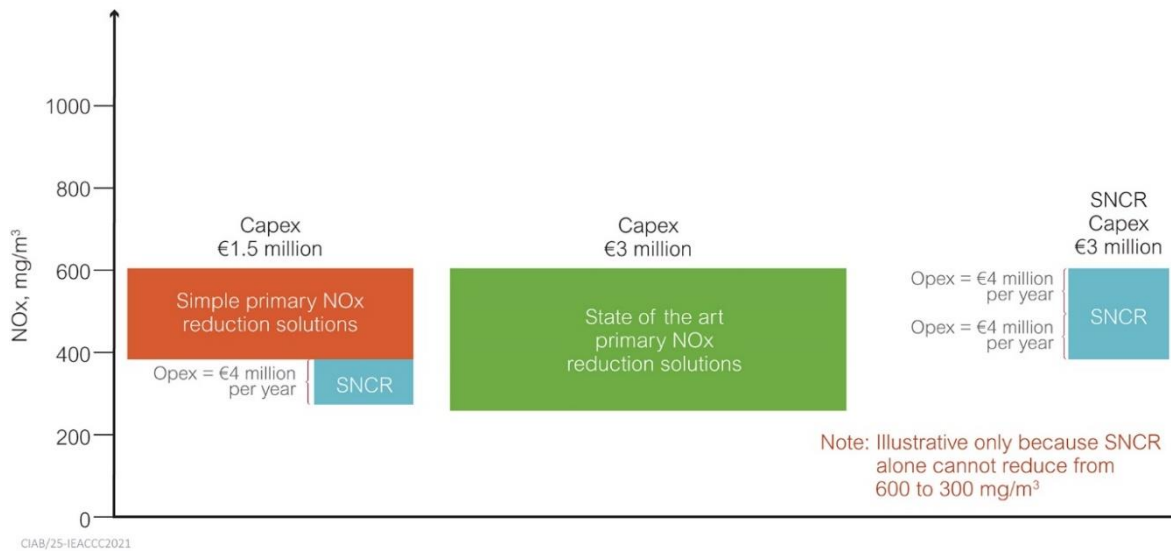


Figure 25 Capex and Opex of SNCR performance for a 500 MW unit, illustrative (Holappa, 2020a)

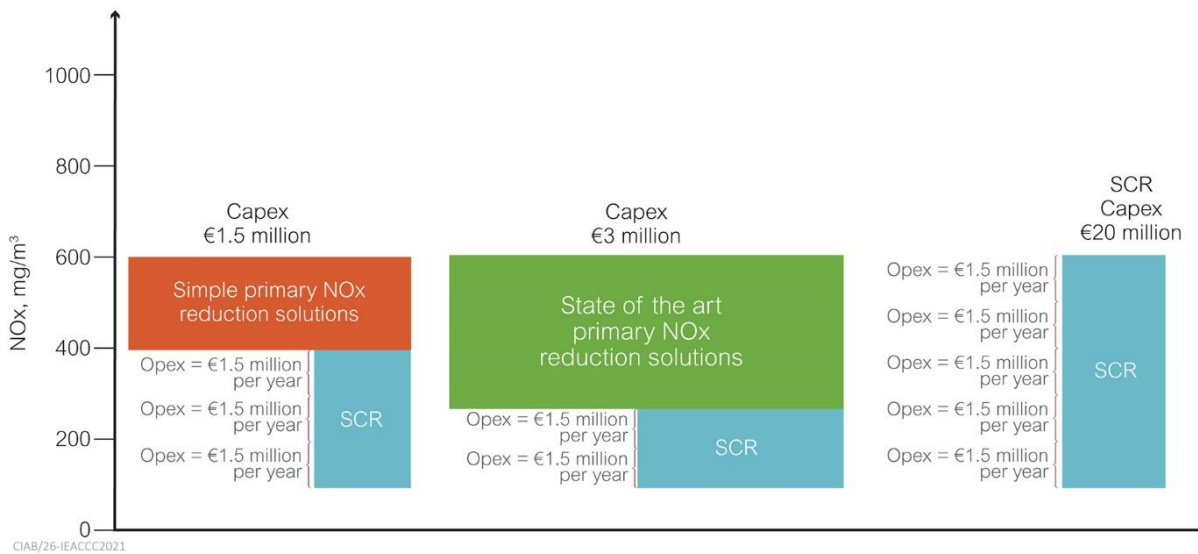


Figure 26 Capex and Opex of SCR performance for a 500 MW unit, illustrative (Holappa, 2020a)

Table 13 lists example costs for primary and secondary NO_x control measures recommended for Indian power plants. It should be noted that the cost will always vary between individual power plants.

TABLE 13 COMPARISON OF COST AND BENEFITS OF USING DIFFERENT NO_x CONTROLS (MODIFIED FROM FORTUM eNEXT, ND; CONRADS, 2020)				
	Advanced fuel & air measurement	Primary NO _x solutions by Fortum eNext* (LNBS+SOFA) + some optimisation	SNCR*	SCR*
Initial investment	€0.2–1.0 million	€3–6 million	€2–3 million	€10–20 million
Opex	NA	NA	€6–15 million depending on the reagent consumption and cost	Approximately €6 million depending on the amount of reagent and catalyst replacement
NO _x reduction	10% by better fuel and air tuning	Up to 70%	20–60%	80–90%
Additional benefits such as increased efficiency, decreased CIA etc	Reduced CIA, reduced slagging, increased efficiency	Lower cost for secondary measures		
* Based on 500 MW unit, operating at full load, 8000 h/y (Fortum eNext, nd) CIA = carbon in ash				

4.4.2 Examples of primary NO_x control success stories from India

CLP Jhajjar, Haryana – two 660 MW units reducing NO_x level to below 300mg/m³

Units 1 and 2 of the CLP Jhajjar plant were both commissioned in 2012. Each has a Harbin boiler, tilting tangentially fired burners, one level of separated overfire air (SOFA) and fires domestic coal with the characteristics shown in Table 14.

TABLE 14 COAL COMPOSITION FOR CLP JHAJJAR HARYANA POWER PLANT (HOLAPPA, 2020B)	
Ash, % dry	39.54
Volatile, % dry	22.48
Fixed carbon, % dry	34.89
Fuel ratio	1.55
N-content in coal, daf	1.805

Fortum eNext, a consultancy based in Finland, carried out a project in 2018-19 with the following main objectives:

- to minimise NO_x emissions to below 300 mg/m³ most of the time without requiring any new hardware or hardware modification; and

- to achieve NO_x reduction under all loads and mill combinations.

The work included:

- computational fluid dynamics (CFD) simulation of hot flame and oxygen streams;
- implementation of new secondary air damper control (SADC) and SOFA damper curves; and
- tuning individual coal burners and coal auxiliary air dampers.

Optimisation work did not impact boiler performance and steam/metal flue gas temperature changes were kept within the design ranges.

Compliance	Before		After	
	Part load, %	Full load, %	Part load, %	Full load, %
Unit 1	38	95	83	98
Unit 2	2.5	34	81	93

The optimisation work resulted in NO_x emissions being below 300 mg/m³ most of the time for different loads (see Table 15). It would be possible to secure 300 mg/m³ at all loads if a second level of SOFA were introduced, and the burners were modified or new ones installed (Holappa and Heinolainen, 2020).

There are various SOFA system designs and they can contain more than one stage. Each stage can have 1 to 4 compartments, each of which has one OFA nozzle. The number of SOFA compartments and stages needed depends on the NO_x emission reduction required and is always determined on a plant by plant basis, using CFD modelling (Holappa, 2020). For example, ROFA (Rotated Overfire Air), a type of SOFA, from Mobotec and SBB Energy, has been installed in two stages in about 100 boilers worldwide (Žmuda, 2020). Successful installations of SOFA in two stages have also been carried out by Fortum eNext. SOFA can be installed both in new boilers and in existing ones, at different size ranges including those below 100 MW and for other firing systems (wall, tangential).

Following SOFA installation, burner modifications or new burners are always required to sustain a stable flame and reach the target emission levels with the best possible efficiency during both low and full load operation. Keeping the correct air/fuel ratio, air flows, even fuel flow distribution between burners and ensuring no air ingress into the boiler is key to achieving the guaranteed performance.

Globally, as environmental standards have tightened over time, LNBS and OFA installation optimisation and combustion modifications have been carried out on different boiler makes and sizes, both new and old (Žmuda, 2020, Holappa, 2020). Installation of combinations of primary measures such as LNBS, OFA and combustion optimisation requires about 4–6 weeks outage, on average. Installation of LNBS alone takes about three weeks, although installation time is plant-specific.

HIL Mahan Aluminium coal power plant – reducing NO_x below 300 mg /m³ at all loads

The plant consists of six subcritical 150 MW units. Unit 3 was selected for combustion optimisation work. It was commissioned in 2013, has a BHEL boiler with tilting tangential burners and coupled overfire air (COFA). The main objective of the project was to reduce NO_x emissions below 290mg/m³ at all loads and with different mill combinations and high ash content domestic coals.

Performance tests have been successfully completed and the NO_x emissions were below the guaranteed values of 290 mg/m³ of NO_x (at 6% oxygen reference) in all mill combinations and load conditions (60, 80 and 100%). The lowest NO_x values reached were well below 200 mg/m³.

Lowering NO_x emissions to 400 mg/m³ by GE SOFA installation in 19 NTPC units

GE has a contract with NTPC to improve NO_x emissions in 19 units, equating to almost 10 GW. Work is ongoing and involves the installation of SOFA. The performance guarantee for all 19 units is 400 mg/m³ at 6% O₂ at the ID fan outlet. So far (late 2020), GE has finished installation of SOFA in Dadri and the Performance Guarantee (PG) test has been completed. The NTPC-Vindhyachal project is implemented and the PG test is expected to be performed soon. Work on a unit at Sipat is also being implemented.

Coal analysis from the Dadri unit is shown in Table 16. Coal and air measurements are taken from the DCS data for that unit. Coal measurement is performed at individual burners while air measurement takes place at each coal mill. No specific modern techniques are used. There possibility remains of lowering NO_x emissions further. This could be achieved by installing another SOFA layer, for example.

TABLE 16 ANALYSIS OF COAL USED AT THE DADRI UNIT			
	Design value	Worst coal*	Best coal*
Ash	41.0	45.0	30.0
Volatile matter	21.0	18.0	26.0
Fixed carbon	25.0	22.0	34.0
FR	0.84	0.82	0.74
Nitrogen	1.4	0.60	1.70
Total moisture	13.0	15.0	10.0
GCV, as given (kcal/kg)	3500	3200	4500
HGI	55	50	60
Ash components			
Silica (SiO ₂)	58.85	59.00	58.20
Alumina (Al ₂ O ₃)	28.80	28.00	29.50
* Table is from the NTPC specification and the terminology 'Worst coal' and 'Best coal' does not necessarily mean this meets GE definition of 'Worst' and 'Best' for NO _x emissions.			

4.4.3 Recommendations for reducing NO_x to around 300 mg/m³ and below

Optimising combustion should be the first action taken to reduce any emissions as it increases plant efficiency and reduces coal consumption per MW generated. Subsequently, primary NO_x control measures should be introduced. The following actions are recommended:

1. Start with a balance of the plant and identify plant-specific areas for improvement.
2. Design and optimise the mill operation. This includes taking care of fuel fineness.
3. Fine-tune the combustion – ideally this should be achieved by the use of advanced online sensors which monitor oxygen and carbon monoxide. The air/fuel ratio and all air streams can then be adjusted accordingly.
4. Ensure the correct air/fuel ratio and fuel distribution between individual burners. This requires using advanced coal flow measurements, ideally those which are drift-free and do not require calibration. There will be a negative impact on the air/fuel ratio in boilers with excessive air ingress; it is important to understand ingress locations and develop a remedial action plan, especially for boilers which deploy LNBS and OFA systems. Subsequent fuel flow control and flow distribution devices are needed to ensure even distribution between individual burners.
5. All air flows (primary, secondary, tertiary and OFA) should be measured, ideally with state-of-the-art digital systems, and subsequently controlled.
6. Install SOFA and modify the existing burners or install new ones. OFA installation must always go in tandem with optimising or modifying burners. The second level of SOFA may be required in some boilers to achieve NO_x emissions below 300 mg/m³ at all loads.

4.4.4 Recommendations for reducing NO_x to 100 mg/m³ and below

Both primary and secondary controls must be employed to achieve NO_x emissions of around 100 mg/m³. Secondary controls include SCR, SNCR or a combination of both. It is important to remember that greater use of advanced primary measures will lower the cost of secondary controls.

In India, full-scale SCR installation has only been implemented at the Harduaganj 660 MW unit which is currently under commissioning, while smaller scale SCR trials, on the slipstream only, have been conducted in the NTPC units (Kumar and Bhagchandani, 2018; Reuters, 2019; Tripathi, 2020). Although secondary measures have not yet been used commercially in India, there is much experience in other countries for operation at both full and part load, including under high-ash conditions. Bearing in mind that plants firing Indian coal typically have particulate (dust) levels of around 50–70 g/m³, Table 17 gives examples of SCR used in similarly high-ash applications in China.

TABLE 17 EXAMPLE OF SCR USE ON HIGH ASH COAL PLANTS IN CHINA (COURTESY OF LABORELEC, 2020)

No	Customer	Application type	Capacity	Dust content, g/m ³	Inlet NO _x , mg/m ³	Outlet NO _x , mg/m ³	Commissioning year
1	Chiping Xinfra Aluminium Oxide Co, Ltd	Aluminium oxide roasting oven	4 x 1350 t/d	150–200	300	80	2018
2	Hunchun Power plant	Coal-fired power plant	2 x 330 MW	73	350	88	2013
3	Huayin Jinzhushanpower plant	Coal-fired power plant	2 x 330 MW	65	1300	150	2013
4	Guizhou Fa'er power plant	Coal-fired power plant	4 x 600 MW	60	550	88	2013

Lessons to learn from tests of SCR on NTPC units

All NTPC tests were performed on a slipstream, not at full scale, and in a 'high-dust', hot-side location, between an economiser and an air heater. Although NO_x removal rates were significant, NTPC noticed problems with erosion of the catalyst and maintaining the temperature in the correct range during part-load operation. NTPC also had other concerns, including the lifetime and replacement cost of the catalyst, and space to retrofit SCR in the existing plants (Reuters, 2019; Tripathi, 2020). The following observations and recommendations are offered for power plants firing Indian coal:

1. A slipstream test is cheaper than a full-scale one, but it cannot mimic the real conditions. Only a full-scale test allows the best operational parameters to be determined and a catalyst to be designed correctly. There are many reasons for this, including that the high-velocity and low-velocity areas of flue gas and their impact on the catalyst cannot be predicted from the slipstream. Also, in comparison to slipstream tests, a full-scale test allows greater scope for modifications to be made to optimise performance. So it is strongly recommended that full-scale SCR installation is implemented.
2. Maintaining temperature at the correct level for the SCR has been achieved worldwide by using well proven solutions such as an economiser bypass, a waterside bypass, or a split economiser. The latter means moving some or all of the economiser banks and placing them after the SCR and is a solution commonly used with SCR retrofits in Poland. Some economisers have also been developed especially to maintain the flue gas temperature at the required level during part load operation and can be used to maintain the required flue gas temperature, such as the B&W V-Temp™ economiser system (B&W, 2020). If this is not possible, chemical injections of magnesium hydroxide are an option.

3. There are various ways to mitigate the erosion and plugging of the catalyst. These include using a wider catalyst pitch and reinforced catalyst walls but also using mechanical methods to remove some of the ash upstream of the SCR reactor.
4. Manufacturers generally guarantee initial catalyst loadings for 8,000 to 24,000 operating hours depending on the design and operating conditions; hence the 8,000–16,000 h achieved during NTPC trials meet these requirements. A proper catalyst management plan, as well as regeneration methods, will prolong the catalyst life (ICAC, 2009).
5. SCR can be placed in a location other than high-dust, hot-side, including after the ESP and before the FGD, when it is known as hot-side, low-dust SCR, or after the FGD which is called tail-end SCR. Both require reheating the flue gas to keep the temperature within the right range for maximum NO_x removal. Placing an SCR in the tail-end location has been well proven in many power plants worldwide including in Poland, Germany and the USA (see Table 18). The advantage of this location is that the catalyst will not be affected by ammonium bisulphate formation and there is no ash present in the flue gas at this point. So, the catalyst will last for a much longer time. It is recommended that tail-end SCR is tested in Indian power plants, especially for those which do not have the space to retrofit traditional SCR.

TABLE 18 EXAMPLES OF POWER PLANTS WITH THE SCR LOCATED IN THE TAIL-END

Plant	Size, MW	Number of SCRs	Fuel	Utility/IPP	Catalyst Supplier	Country	Remarks
KW West (unit 1 and 2)	700	2	Bituminous coal	STEAG	KWH*	Germany	CHP
KW Lunen (unit 10/11)	527	2	Bituminous coal	STEAG	KWH*	Germany	CHP
KW Herne (unit 1–3)	700	2	Bituminous coal	STEAG	KWH*	Germany	CHP
HKW West 1 & 2	2x280	2	Bituminous coal	Volkswagen	Siemens	Germany	CHP
KW Lausward	6x200	12	Bituminous coal	Stadtwerke Duesseldorf	KWH	Germany	CHP
KW Ibbenbüren	770	2	Bituminous coal	RWE	Siemens	Germany	
HKW Hannover	2x280	2	Bituminous coal	Stadtwerke Hannover	Siemens	Germany	CHP
KW Siersdorf	175	1	Bituminous coal	EBV	Siemens	Germany	CHP
KW Reuter (unit 1, 2)	230	2	Bituminous coal	BEWAG	Siemens	Germany	CHP
Mercer 1&2	2x325	2	Bituminous coal	PSE&G	CERAM	USA	
South Oak Creek	2x600	4	PRB	WE Energies	Cormetech	USA	
Skawina	5x70	2			SBB Energy	Poland	CHP
Total		35					

Lessons to learn from SNCR trials on NTPC units

Short trials of SNCR were carried out on two 500 MW NTPC stations: unit 4 of Rihand plant by GE and unit 12 of Vindhyachal plant by Yara.

NTPC concluded that the SNCR was not effective enough, the use of reagent would be problematic and there were also concerns about lowering unit efficiency, increasing CO₂ emissions, water use, impact on pressure parts (in case of incorrect injection of urea and the wrong location), formation of nitrous oxide, fly ash contamination (in case ammonia slip is more than 5 ppm), air preheater fouling due to formation of ammonium bisulphate and plume formation. Other concerns included the use of the technology on larger boilers.

Based on these trials and other experience with SNCR, the following observations are made:

1. The efficiency of SNCR depends largely on where the reagent is injected. The right temperature window depends on CO, oxygen and temperature, which change with the plant load (as seen in Figure 27). So they must be monitored and subsequent adjustments made to the injection location. Using the existing openings for soot blowers as ports for SNCR lances is not ideal. When reagent is injected in the appropriate temperature window, NO_x can be reduced by up to 60%. The maximum reduction achieved of 35% is not surprising as the necessary modifications were not carried out.

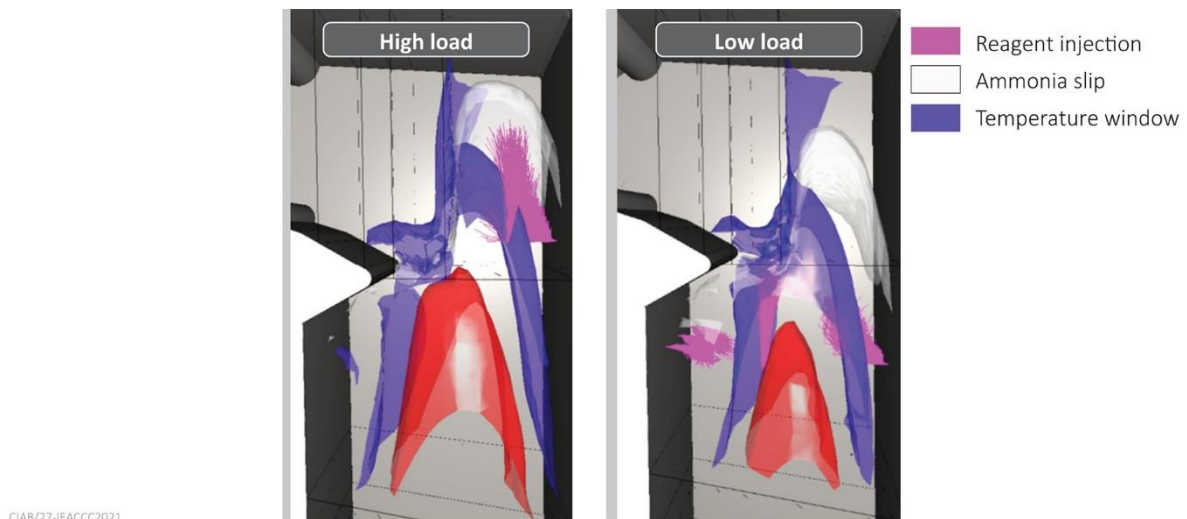


Figure 27 SNCR temperature window during part-load and full-load operation (pink – the reagent injection, white – ammonia slip, purple – temperature window) (Image courtesy of Fuel Tech srl, 2019)

2. Systems which inject reagent with air in contrast to those which use water as a carrier are recommended for regions with concerns about water availability.
3. Installation on larger boilers can be problematic but recent advances in monitoring of key combustion parameters make it possible. There is experience with SNCR on larger boilers, (up

to 660 MW) in China, for example. The online, accurate monitoring of combustion parameters and state-of-the-art systems are required in such cases.

4. SNCR is applied in tandem with primary measures worldwide; it is unusual for it to operate as the only method of NO_x control.
5. Overall, on larger, new boilers, SCR is a more effective option than SNCR, or both systems can be applied in tandem. This allows for a smaller SCR reactor, and SNCR can be used alone during part load, for example, or with SCR during full-load operation.

4.5 OVERALL RECOMMENDATIONS FOR LOWERING AIR POLLUTION IN INDIA

The only possible trend in emission standards for coal-fired power plants worldwide is for them to be tightened further. This has already happened in many countries. India has a great opportunity to reduce emissions significantly from the coal power sector. This would benefit the health of many Indian people and thus the economy as well. It is considered important to implement the norms uniformly across the country, as both SO_x and NO_x can bond to particulate matter and travel many hundreds of kilometres, causing negative impacts over an extensive area.

In India, the implementation of SO_x controls and the upgrading of PM controls are behind schedule to comply with the deadlines, but some progress is being made. However there seems to be more doubt about the suitability of NO_x control technologies for Indian coal which are needed to meet the standards for new coal and existing power plants. Technologies for NO_x emissions control are effective and proven even with high ash coals. Generally primary NO_x controls are not affected by high-ash coal. Further, high ash coal does not impact SNCR. While there is some impact on SCR, there are solutions available which can mitigate the impact of high-ash coal and the abrasive nature of alpha quartz in particular. The following steps are recommended:

1. The human, environmental, and economic cost of not reducing pollution and delaying the implementation of emission controls should be weighed against the cost of installing and running the control technologies.
2. Strong incentives to comply with the norms should be considered, such as placing the cleaner and more efficient plants higher in the merit order or issuing stronger penalties for those who do not take action to mitigate pollutant emissions.
3. The NO_x emission reduction strategy should start with the basics as significant NO_x reduction, of approximately 10%, can be achieved through fundamental optimisation of power plant processes, including combustion optimisation. This must include the monitoring and fine tuning of parameters such as air/fuel ratio, mill performance and coal fineness, excess oxygen, and air and coal flow rates.

4. The installation of effective primary NO_x controls such as separated overfire air and low NO_x burners will be facilitated by savings on fuel due to combustion optimisation. Appropriate measurement and control systems are essential as these systems require precise control of combustion parameters (including all combustion air streams, oxygen level, air/fuel ratio and particle fineness).
5. More trials of SCR, but on a full scale, are recommended. These should include trying different locations for SCR such as after the FGD, where there is no ash present in the flue gas. Both SCR and SNCR should always be installed in tandem with primary measures such as OFA and LNBS.
6. Spikes in emissions occur naturally during start-up, for example, and are not representative of standard operation. It is recommended that emission norms should be met on an average basis over a specified period. This would mean that the lower emission standards such as 300 mg/m³ could be met with primary measures alone at most of the units built between January 2004 and January 2017. Such an approach has been taken in Europe and other countries where plants have to comply with the average daily and yearly norms.
7. It is important that clear guidance on how to measure and report emissions should be in place.
8. Those plants commissioned before 31 December 2003 which are not very different from those commissioned after January 2004 could meet the 450 mg/m³ on an average basis, and revision of their 600 mg/m³ standard is recommended.
9. The limit of 100 mg/m³ for plants built after January 2017 is advised to be upheld. This level of reduction can be met with a combination of advanced primary methods, appropriate operating and maintenance practice and SCR or SCR/SNCR.
10. Following successful implementation of the current emission standards and when industry has confidence in operating the control systems, future tightening of the norms should be considered.

5 CARBON CAPTURE, UTILISATION AND STORAGE IN INDIA

5.1 BACKGROUND TO CCUS IN COAL POWER

Carbon capture, utilisation and storage (CCUS) describes the process of separating the CO₂ emitted by combustion or other industrial processes, before converting the gas to useful products or sequestering it in suitable geological formations. Application of this technology to enhanced oil recovery (EOR), in which the CO₂ is injected into mature oil wells to boost production, has been established in North America since the 1970s. Large-scale dedicated CO₂ storage for the purpose of avoiding greenhouse gas emissions was first demonstrated at Norway's Sleipner offshore gas platform in 1996, where CO₂ is removed from the natural gas itself and stored in a saline aquifer formation beneath the North Sea (IEA, 2016). This began a period of growing international interest in CCS as a climate change mitigation solution, with a strong focus on application of the technology to coal-fired power plants. Despite several unsuccessful initiatives to demonstrate the technology at large-scale, particularly in Europe, 28 commercial CCS facilities have been realised on various industrial processes around the world (GCCSI, 2020). However, only two of these are associated with coal power plant: Boundary Dam 3 in Saskatchewan, Canada, which started in 2014, and Petra Nova in Texas, USA, commissioned in 2017. Like most current projects, both these facilities rely on revenues from CO₂ use for EOR. In fact, the Petra Nova capture facility is currently mothballed as the low price of oil renders the EOR process uneconomic (Lockwood, 2020b).

In the past few years, there has been a marked resurgence in efforts to advance CCUS, driven by more ambitious climate targets associated with the Paris Agreement and national pledges to achieve 'net-zero' emissions. This renewed interest has featured a growing focus on the application of CCUS to industrial processes such as steel, cement, and chemicals production rather than the power sector (IEA, 2020c). While there remains uncertainty over how best to generate revenue streams for CO₂ storage without EOR, a significant tax credit incentive for CO₂ storage introduced in the USA in 2017 is a key development in this regard (Legal Information Institute, 2017). This initiative is driving several new projects, including five associated with full-scale capture from coal power plants which have also received US Department of Energy (DOE) support for FEED studies (US DOE, 2019; Kelsall, 2020). In China, a few medium-scale (0.2–1 MtCO₂/y) CCS projects have been realised in the natural gas and coal-to-chemicals sectors, but ongoing plans for power sector projects have tended to move slowly (Lockwood, 2018).

In general, there is a growing trend towards the development of CCUS 'clusters', where shared CO₂ transport (pipeline or shipping) and storage infrastructure is established in regions with a high density of emitting industries (IEA, 2020c). CO₂ storage would then likely be operated as a regulated service with fixed returns – reducing the investment risk on both the storage and capture side. This model is most advanced in Europe, with several planned clusters including those associated with the Port of

Rotterdam (Porthos) in the Netherlands, Teesside in the UK (Net Zero Teesside), and Norway's Longship project (Porthos, 2020; Net Zero Teesside 2020; CCS Norway, 2020). The Oil and Gas Climate Initiative (OGCI) have also identified and invested in several 'kickstarter' CCS clusters in promising locations around the world (OGCI, 2019).

5.2 CCUS RESEARCH AND DEVELOPMENT IN INDIA

The Government of India has supported CCUS R&D since the early 2000s, when the technology was first attracting international interest. For example, in 2003, India became a founding member of the Carbon Sequestration Leadership Forum and the Global CCS Institute. In 2007, the Department of Science and Technology (DST) launched a National Programme on Carbon Sequestration, which included research funding for microalgae-based capture, other capture processes, and policy development, as well as covering the promotion of natural carbon sinks through forestry and agriculture. In the same year, the Indian CO₂ Sequestration Applied Research (ICOSAR) network was established to help coordinate researchers in this field (Kapila and Haszeldine, 2008; Viebahn and others, 2011; Sood and Vyas, 2017; Chase India, 2019).

Some major state-owned companies have also undertaken CO₂ capture R&D, though at a relatively small scale. NTPC's research institute NETRA (NTPC Energy Technology Research Alliance) has supported research into solvent and sorbent-based capture approaches in collaboration with several technical institutes, but this work has remained at the laboratory and bench scale. At a larger scale, NETRA developed an open-pond algae-based capture facility at NTPC's Faridabad gas power plant in 2013, with the aim of converting the micro-algae into biofuels such as biomethane and bio-diesel (Srivastava, 2018). However, the company has concluded that such algae-based initiatives are ultimately not sufficiently economic to pursue further. A similar open-pond algae facility was established in 2013 by aluminium producer Nalco, using flue gas from a captive coal plant (Zhang, 2015). In 2010, power plant equipment manufacturer BHEL investigated oxyfuel combustion of coal, in which coal is fired in a mix of oxygen and recycled flue gases as a means of producing a purer stream of CO₂ (Goel and Verma, 2009). Other significant capture research in India includes a solvent-based pilot unit operated at RGPV University, which captures up to 500 kg/d of CO₂ from a small gas-fired boiler and a biomass gasifier (Sethi and others, 2018). In August 2020, NTPC put out a public tender for the construction of a 20 tCO₂/d pilot capture plant at the Vindhyachal coal-fired power plant in Madhya Pradesh (NTPC, 2020).

In 2015, India joined 23 other countries in the Mission Innovation initiative, which is centred on commitments to raise public funding for clean energy research and promoting collaboration between the members. As part of efforts under the initiative's Innovation Challenge on carbon capture (known as IC3), the DST launched a research call in 2018, and has supported 19 projects to date with around €2 million (US\$2.4 million) of funding. In general, India retains a strong interest in CO₂ conversion to

fuels (utilisation), which represents 39% of the total funding and features to some extent in 12 of the projects (see Figure 28) (DST, 2020).

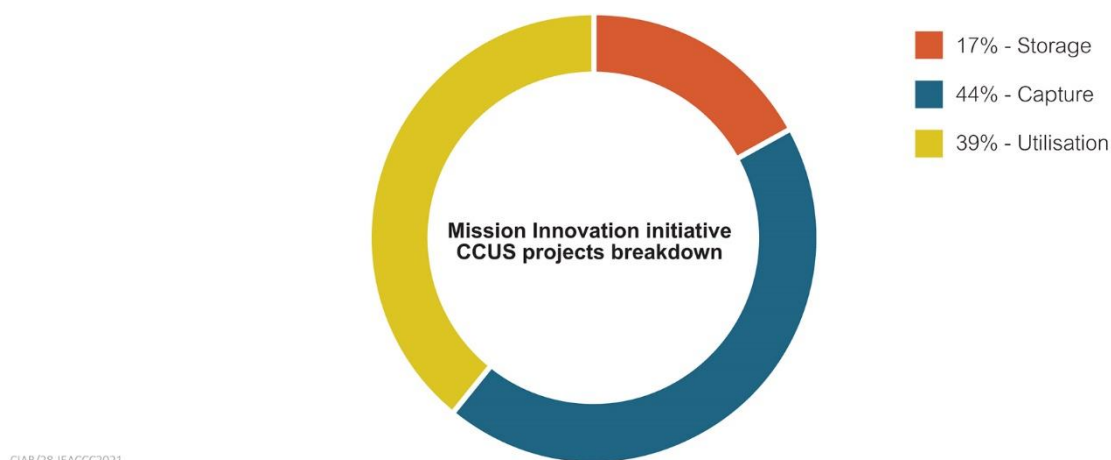


Figure 28 Breakdown of DST funding for CCUS projects under Mission Innovation IC3

In July 2020, India joined the EU-based research programme Accelerating CCS Technologies ‘ACT’, and has contributed €1 million to the initiative’s 3rd call for research projects (ACT-3). This call for proposals was open until November 2020, with projects expected to start in September 2021. Also in 2020, the DST set up two centres of excellence in CCUS: one at IIT Bombay focused on storage research, and one at JNCASR devoted to utilisation research; both institutes are already well-established centres of academic expertise in these fields (DST, 2020)

5.2.1 Industrial CCUS activity

India is the world’s second largest producer of cement, steel, and fertilisers after China, and non-power industrial emissions amounted to nearly 600 MtCO₂ in 2018 (compared to 1100 Mt from coal power) (IEA, 2019a). In recent years, interest in these sectors in CCUS has grown, as there is often no alternative route to decarbonisation, and stronger revenue streams (relative to the power sector) may be more able to absorb the additional cost of the process. As a driver for the development of a general CCUS infrastructure in India, such developments remain relevant to the power sector, particularly regarding the potential for industrial clusters with shared CO₂ networks, as currently planned in various European locations.

India’s large fertiliser industry has a high demand for CO₂ as a feedstock for the production of urea, much of which is supplied from the concurrent production of ammonia, which is also needed in urea synthesis. Several large urea plants have applied Mitsubishi’s CO₂ capture technology to the natural gas reformers used in ammonia production, including the Phulpur and Aonla urea plants commissioned in 2006, which each produce up to 450 tCO₂/d (Gupta and Paul, 2018). While this kind of process cannot strictly be considered a CO₂ abatement activity, it highlights established experience with capture technology and a demand for CO₂ which could potentially be served with abated emissions.

In 2016, India's first truly industrial-scale CCU process was launched when Carbon Clean Solutions (now Carbon Clean) commissioned a 174 tCO₂/d unit at a plant belonging to Tuticorin Alkali Chemicals and Fertilisers in Tamil Nadu, using CO₂ captured from a small, captive coal-fired boiler (Carbon Clean, 2016). This commercial venture provided CO₂ for the production of soda ash (sodium carbonate – also used as a fertiliser), and served as the first industrial demonstration of Carbon Clean's novel solvent-based capture process, which claims to achieve a highly competitive capture cost of 30 US\$/tCO₂ in this context. Although headquartered in the UK, Carbon Clean was founded by two Indian engineering graduates and retains a strong interest in developing CCUS in India. In 2019, the technology provider signed a Memorandum of Understanding (MoU) with Dalmia Cement, which has signalled its intention to develop a 0.5 MtCO₂/y facility at its cement plant in Tamil Nadu (Carbon Clean, 2019).

In the oil industry, some CO₂ capture research has been conducted by Reliance Industries at the Jamnagar refinery in Gujarat (the world's largest), where a pilot facility using Algenol's reactor-based algae technology was deployed in 2015 (Biofuels International, 2015). Reliance Industries have declared a target to turn net-zero by 2035, with a strong interest in CO₂ conversion into pharmaceuticals, fuels, and advanced materials (Economic Times, 2020d). Despite leaving the OGCI in 2018, the company has also invested in Canadian capture technology provider Inventys and Solidia® – a US-based company using captured CO₂ in concrete production (Rathi, 2018). Public sector undertakings in the oil and gas industry, including the Oil and Natural Gas Corporation (ONGC), Oil India, and Indian Oil, have shown growing interest in CO₂ capture for enhanced oil recovery, described in Section 5.3.2.

In 2018, India's largest steel producer, Tata Steel, committed to make its European operations (Tata Steel Europe) carbon neutral by 2050, with a strong focus on CCUS (World Steel Association, 2019). To this end, the company joined Gasunie, EBN, and the Port of Amsterdam to conduct a feasibility study on developing a shared CO₂ network in the Amsterdam region, close to Tata's Ijmuiden blast furnace. The Ijmuiden plant also hosts a pilot plant for HIsarna blast furnace technology, which is considered more compatible with CO₂ capture (Hall and others, 2020). However, there are currently no plans for CO₂ capture deployment at Tata's Indian locations, and the country's other major steel producers (JSW, Steel Authority of India) have yet to express an interest in the technology. Given the location of most major steel plants in the coal-producing states, the steel sector potentially has the greatest potential for forming CCUS clusters with coal power plants (Garg and others, 2017).

5.3 GEOLOGICAL STORAGE ASSESSMENT

A detailed survey of suitable formations for CO₂ storage is a prerequisite for the development of geological CO₂ storage in any region. The most promising geology for CCUS is the porous rock found in sedimentary basins, which include deep saline aquifers or oil and gas reservoirs. A 'cap rock' of less permeable rock is required above the porous storage region to prevent upwards migration of the

injected CO₂. Assessments for CO₂ storage capacity can be carried out at varying levels of detail, starting with a broad appraisal of a whole sedimentary basin, down to investigation (through geophysical measurements and test drilling) of an individual formation, such as an appropriate saline aquifer (Bachu and others, 2007; Ajayi and others, 2019). Regions with comprehensive storage capacity assessments, including Europe's North Sea or parts of the USA, have often benefited from surveys associated with oil and gas exploration which are released into the public domain.

5.3.1 Storage capacity overview

There is currently very limited knowledge of India's CO₂ storage potential, and several current estimates are based on a study conducted by the British Geological Survey for IEAGHG in 2008 (IEAGHG, 2008). This work provided a qualitative assessment of the suitability of the major sedimentary basins in India and the rest of the sub-continent, as well as suggesting a rough approximation of the potential capacity of suitable basins. As shown in Figure 29, a basin was broadly categorised as 'good' if currently producing hydrocarbons, as this indicates the presence of a suitable cap rock layer. These regions include the Cambay Basin in Gujarat and Mumbai Basin in offshore Maharashtra, the Cauvery Basin along the south-east coast (Tamil Nadu and Andhra Pradesh), and the Assam Basin in North-East India. Basins categorised as 'fair' were those expected to have some hydrocarbon resources, while those labelled 'limited' have no hydrocarbon production and less promising geology for CO₂ injection.

The inland sedimentary basins close to the major coal-producing (and coal power cluster) states of Jharkhand, Chhattisgarh, and Madhya Pradesh were considered limited in the 2008 study, due to various factors, including the expected absence of good caprock, or the risk of contaminating freshwater aquifers (in the case of the large and densely populated Ganga basin). However, it should be noted that the Damodar Valley basin, which covers a major coal producing area in northern Jharkhand, is considered potentially favourable, subject to further investigation. The Vindhyan and Satpura basins in eastern Madhya Pradesh, and the Indian part of the Bengal Basin (gas fields are present on the Bangladesh side) are also thought to be worthy of further study for suitable formations. Another promising option for storage for the eastern coalfield and power plant cluster areas appears to be the coastal Mahanadi basin, for which the deep offshore section is actually considered 'good' (IEAGHG, 2008).

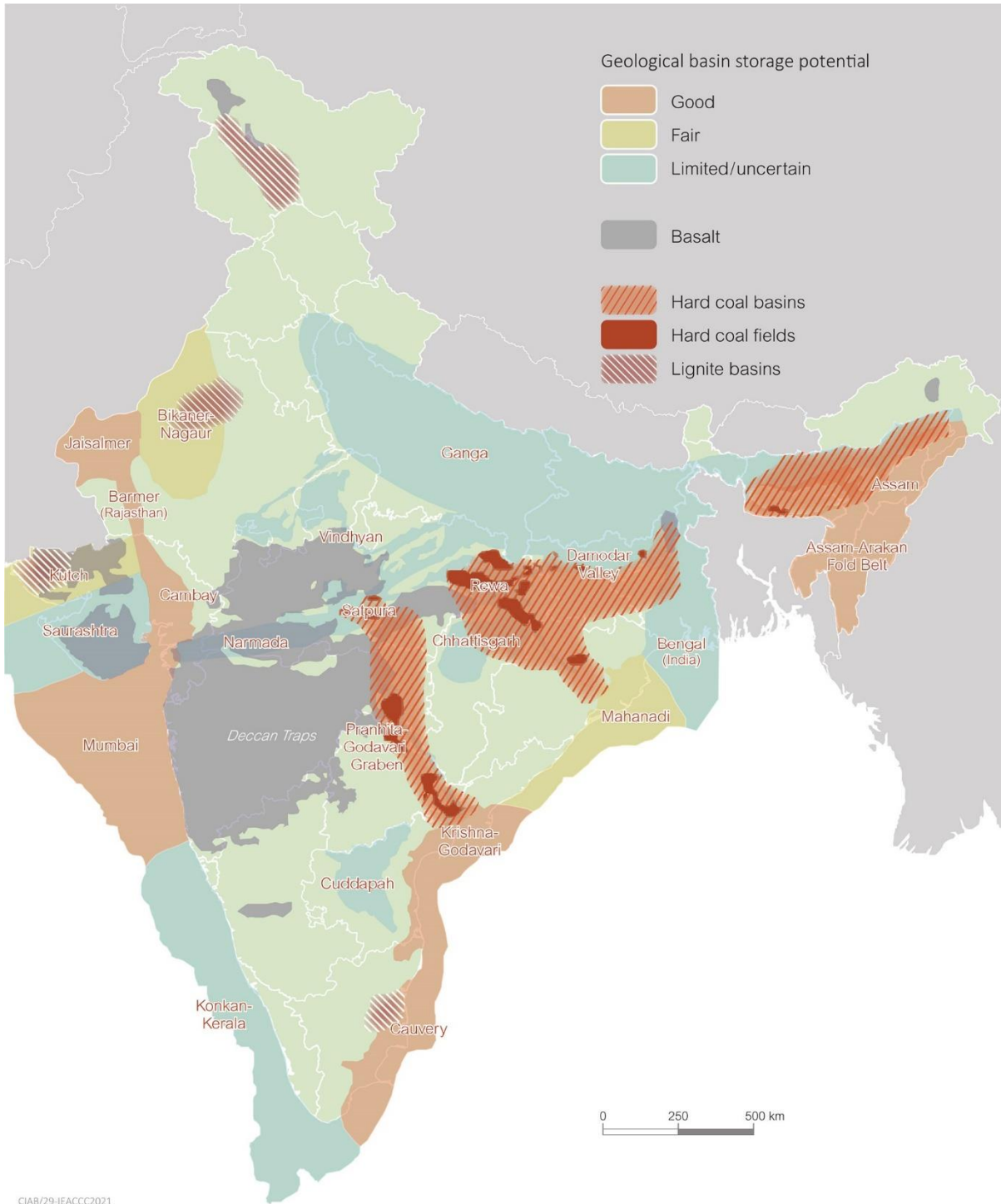


Figure 29 Potential CO₂ storage locations in India, showing sedimentary basins (assessed for CO₂ storage suitability), basalt, and coal fields (IEAGHG, 2008)

Table 19 reviews various estimates for India’s overall storage capacity, differentiated by the type of geological formation or reservoir. It is clear that the potential capacity associated with saline aquifers is the most significant, however, these figures all represent rough approximations based on the area of the sedimentary basins alone. In the case of the IEAGHG assessment, this follows a method in which 50% of the basin area is assumed to contain suitable saline aquifers and a CO₂ capacity of 0.2 MtCO₂/km² is applied to the resulting area. The lower estimate provided by this study is due to the

further vetting of basins according to their geological suitability, with only basins ranked as ‘good’ or ‘fair’ potential considered in the total (Singh and others, 2006; IEAGHG, 2008). A global assessment of CO₂ storage capacity by Kearns and others, 2017, used a similar method, but also took into account actual basin thickness data to calculate the available volume of sedimentary basins. A CO₂ storage efficiency of 0.037 MtCO₂/km³ was taken as a lower bound and 0.26 MtCO₂/km³ as an upper bound, with offshore sites restricted to those within 200 miles of shore and at water depths below 300 m. This approach obtains a lower bound estimate of 99 Gt of storage capacity for India (including 25 Gt offshore), which is further cited in IEA, 2020d. As the lower bound assumptions become comparable to the IEAGHG method at a formation thickness of around 100 m, which is fairly typical, the increased estimate can be largely attributed to the inclusion of all onshore basins (despite consideration of a slightly reduced offshore area).

The IEAGHG lower estimate of saline aquifer and oil and gas reservoir capacity would still represent the ability to store over 20 years of India’s total 2018 CO₂ emissions, or 46 years of coal power emissions (at 2018 levels). Furthermore, the saline storage potential of the non-hydrocarbon producing basins should not be disregarded; the true potential of these regions will only be conclusively determined by drilling exploratory wells for more detailed characterisation (Singh U, 2020).

Storage, Gt	Dooley and others, 2005	Singh and others, 2006	IEAGHG, 2008	Singh and Mohanty, 2018	Kearns and others, 2017
Oil fields	–	7	1–1.1	–	–
Gas fields	2		2.7–3.5	–	–
Saline aquifers	102	360	47 (good) 63 (good and fair)	–	99 (lower) 697 (upper)
Basalt	–	200	–	–	–
Coal seams	2	5	0.345	4.5	–

5.3.2 Opportunities for enhanced oil recovery

The most active area of CO₂ storage development in India is in enhanced oil recovery (EOR). While proposals for CO₂-based EOR have existed since around 2010, a recent surge in interest has been driven by draft legislation known as the ‘Policy framework to promote and incentivise enhanced recovery methods for oil and gas’, introduced by the Directorate General of Hydrocarbons in 2018. Aimed at increasing India’s oil production and reducing reliance on imports, the draft document suggested incentives such as a waiver in the oil cess (a production tax) and an up to 10% increase in the price at the wellhead over a ten-year period (Ministry of Petroleum and Natural Gas, 2018). This

would cover enhanced production using water, CO₂, or polymer injection, all of which can act to displace oil through increasing reservoir pressure and reducing oil viscosity.

Most CO₂-EOR plans have been initiated by the ONGC and are associated with onshore oil production in the Cambay basin region in Gujarat (see Figure 30). As early as 2010, ONGC conducted an investigation into the use of CO₂ from its Hazira gas plant to boost production in the Ankleshwar oil field, but these plans did not progress (Ganguli, 2017). In 2019, ONGC entered into an MoU with NTPC with a view to using CO₂ from NTPC's Jhanor Gandhar gas power plant, and a further MoU with Tamil Nadu's IL&FS power company related to capture from a coal plant and EOR in the Cauvery Basin (ONGC, 2019a). Currently most likely to proceed, however, is a proposal between ONGC and Indian Oil Corporation Ltd (IOCL), aimed at capture from IOCL's Koyali Refinery, with the CO₂ used to boost production at ONGC's Gandhar field on the Gulf of Cambay coast (ONGC, 2019b). Another promising project is located on the other side of the country in Assam, where IOCL and Oil India have signed an MoU relating to capture from the Digboi oil refinery for EOR in the Nahorkatiya and Dikam fields, 50–60 km away (Hindu Business Line, 2020). In general, early interest in EOR has focused on using CO₂ emissions from oil and gas industry sources, rather than the coal power sector.

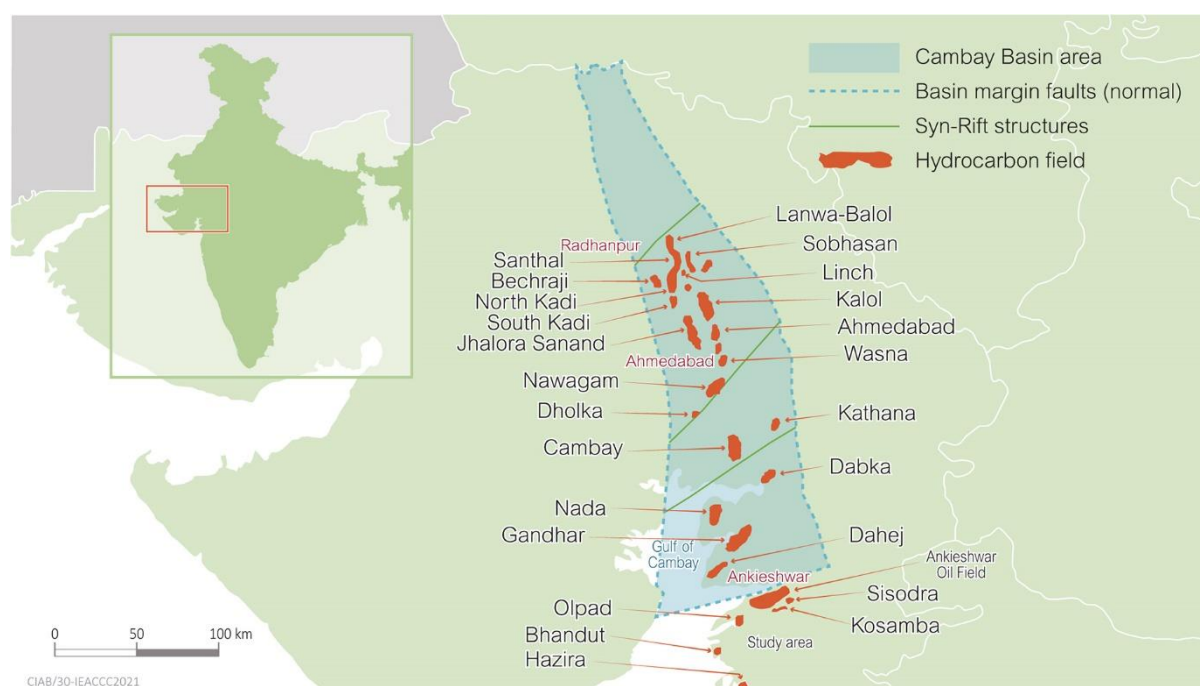


Figure 30 Oil fields in the Cambay Basin (Ganguli, 2017)

5.3.3 Other forms of geological storage

India also possesses a large central region of basalt rock (shown in blue in Figure 30) known as the Deccan Traps, as well as some smaller basalt regions in other parts of the country (Shukla and others, 2020). Basalt is thought to have potential for CO₂ storage as, owing to the manner of its formation from lava flows, it often consists of alternating layers of porous and less permeable rock (IEAGHG, 2017). Large-scale trials on CO₂ storage in basalt have been conducted by the Wallula Project, Washington

State, USA (started 2013) and by CarbFix in Iceland (started 2012), yielding good results for CO₂ retention. Basalt storage has attracted particularly positive interest due to the relatively rapid conversion of CO₂ to solid carbonates within the rock (mineralisation), although this also depends on the injection method. At CarbFix, where CO₂ is dissolved in water during the injection process, mineralisation is accelerated and over 80% of the CO₂ injected formed carbonates within a year (Gislason and Oelkers, 2014). However, a potential drawback with this method, particularly for application to India, is the large quantities of water required – only 5% of the injected mass is CO₂ (IEAGHG, 2017). In 2007, a collaborative research project to investigate the CO₂ storage potential of Deccan basalt was proposed by NTPC, India's National Geophysical Research Institute, and the Pacific North-West National Laboratory in the USA, but it failed to progress beyond laboratory sample analysis. The British Geological Survey is currently conducting a relatively small research project into CO₂ storage in Indian basalt (Pearce, 2020).

There is also potential for CO₂ to be stored in deep coal seams, due to the molecule's tendency to adsorb onto the coal surface (Vishal, 2017). As this adsorption usually displaces coal-bed methane (CBM), there has been considerable research interest (in India and globally) in enhanced CBM, in which CO₂ storage is coupled with greater production of methane. The Government of India has actively promoted conventional CBM since the mid-1990s, leading to several large-scale production sites, primarily in the Damodar Valley (DGH, 2018). Although CO₂ injection has been found to cause the coal mass to swell, to some extent inhibiting methane production from the seam, there is still potential for enhanced CBM to act as CO₂ storage at lower injection rates (Sloss, 2015b). Furthermore, coal fields with good characteristics for CBM production, such as high permeability and porosity, are also most suitable for CO₂ storage (Singh and Hajra, 2018). Existing estimates for the CO₂ storage capacity of Indian coal fields are often low due to ambitious assumptions for the quantity of coal which could be mined in future (IEAGHG, 2008; Singh and Mohanty, 2018). Based on India's current production targets, and the slow development of underground mining, recent work by Singh U (2020) and others suggests that the coal seam capacity could be increased by an order of magnitude. Most promisingly, coal seam storage is well located for existing coal power plant clusters, with the Raniganj, Jharia, and Bokaro coal fields in the Damodar Valley area showing particularly high potential (Das and Datta, 2017; Singh and Mohanty, 2018; Singh U, 2020).

5.3.4 Current research activity

As part of the projects funded under Mission Innovation IC3, IITB is leading a project 'A systematic large-scale assessment for potential of CO₂ enhanced oil and natural gas recovery in key sedimentary basins in India', involving the identification of suitable geological formations for CO₂ storage close to large point sources, physical studies of a selected mature oil reservoir and CBM reservoir, and evaluation of reservoir integrity (DST, 2019). The British Geological Survey is leading a smaller, complementary project funded by the UK government looking at 'containment risk mitigation in Indian CO₂ storage' (COMICS) (UKRI, 2019). This initiative will work with researchers from IITB and

the National Geophysical Research Institute (India), as well as several industrial partners, to develop recommendations for secure CO₂ storage in the Cambay Basin region.

5.4 CO₂ UTILISATION

The conversion of CO₂ into useful products, such as hydrocarbon fuels, chemicals, or cement, has enduring appeal as a means of providing a revenue stream for carbon capture. As CO₂ is a relatively stable, oxidised molecule, conversion processes involving a reduction reaction can be challenging in terms of their cost and demand for energy or hydrogen. These challenges have given rise to an active field of research, and a host of novel processes have been developed for the more efficient conversion of CO₂ (Figure 31) (Zhu, 2018). Notable research programmes include the DOE Office of Fossil Energy CO₂ utilisation programme and the Carbon Recycling initiative in Japan, as well as competition-based funding such as the NRG Cosia Carbon XPrize and the ERA Grand Challenge (US DOE, 2020; NEDO, 2020; Carbon XPrize, 2020; ERA, 2020)

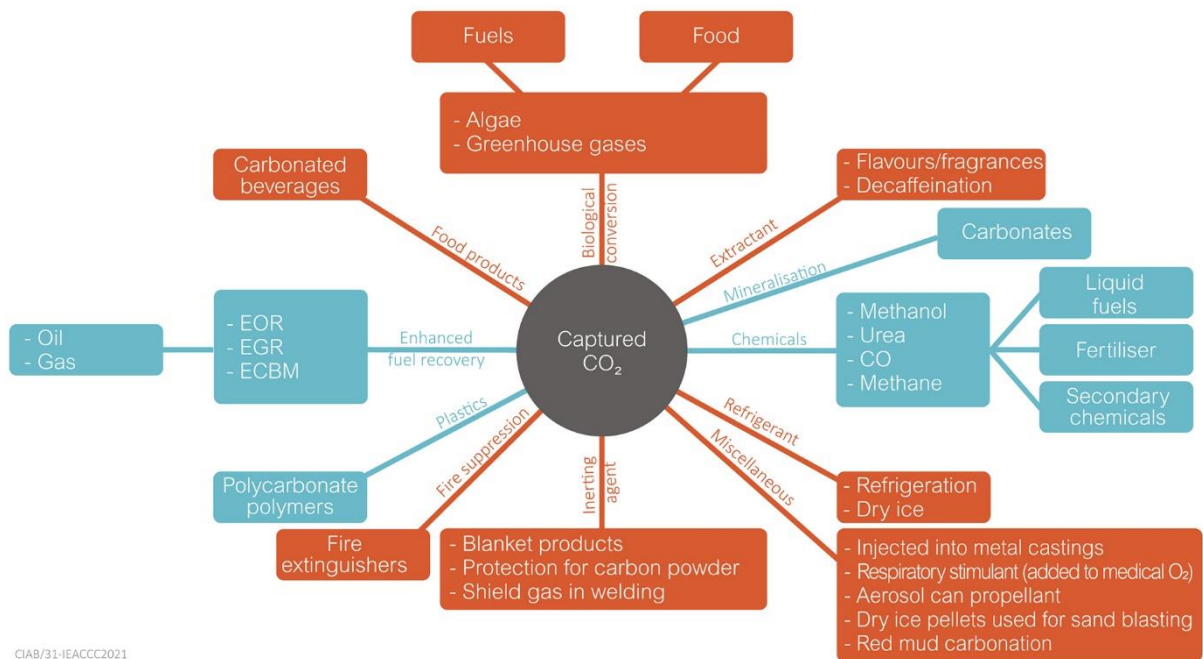


Figure 31 Potential uses for CO₂ (Zhu, 2018)

However, the carbon abatement potential of CO₂ conversion technologies is contentious and the subject of ongoing discourse. While applications in long-term products such as cement and (to a lesser extent) plastics can be considered stable carbon sinks, the effect of short-lived uses in fuels or fertilisers requires complex analysis of life cycle emissions relative to a reference scenario in which conventional hydrocarbon feedstocks are used (IEAGHG, 2018; Bobeck and others, 2019). The scale of emissions which can be tackled through conversion technologies is also thought to be small relative to geological storage capacity (IEA, 2020c). Nevertheless, this approach is widely seen as an effective means of driving early carbon capture developments.

India's CCUS R&D efforts have maintained a strong focus on CO₂ conversion technologies, as they represent both a means of reducing India's reliance on imported oil and gas, and providing a revenue stream for CO₂ capture activity. As discussed, early research has included an interest in the use of microalgae for the capture and conversion of CO₂ to biofuels, while Carbon Clean's industrial capture pilot is associated with soda ash production. Utilisation-based research projects under the DST's Mission Innovation IC3 funding are primarily aimed either at developing dry reforming of methane to syngas (using CO₂ instead of steam), or the direct reduction of CO₂ to methanol, carbon monoxide, or dimethyl ether. These products can be used either as fuels or as feedstock for the synthesis of other hydrocarbon chemicals, and interest in their domestic production is closely linked with the Methanol Economy initiative described in Section 5.6. Optimisation of these processes for cost and efficiency relies heavily on the development of novel catalyst materials.

Breathe Applied Sciences (Breathe) is a notable technology start-up based on CO₂-to-methanol research at the Jawaharlal Nehru Centre for Advanced Scientific Research. Incorporated in 2016, Breathe is a finalist in the US\$20 million NRG Cosia Carbon Xprize, which aims to identify and develop breakthrough technologies for converting CO₂ into useful products (Breathe, 2020). The company has also received backing from the Karnataka State Government. Bench-scale trials of Breathe's conversion technology achieved 35–40% conversion efficiency to 90% methanol and 10% carbon monoxide, with a projected methanol production cost at around 70% of the market price (~0.45 US\$/kg in India). Pilot scale facilities are under construction close to the company's base in Bengaluru, and at the Wyoming test site (Dry Fork coal power plant) for Carbon XPrize finalists. The company has the goal of capturing 10% of India's 2 Mt methanol market, and are in discussions with emitters such as Tata Power, Shell, Bharat Petroleum, and Coal India (Peter, 2020).

In 2020, NTPC signed an MoU with Larsen and Toubro Hydrocarbon Engineering to build a CO₂-to-methanol demonstration facility at an NTPC power plant, with a view to commercialising the technology (PSU Watch, 2020). Currently, the only commercial-scale CO₂-to-methanol plant operating worldwide is the George Olah plant in Iceland (commissioned 2012), which converts up to 5.6 kt of CO₂ to 5 million litres of methanol a year, using geothermal energy for hydrogen production (Carbon Recycling International, 2020).

5.5 POTENTIAL FOR CCUS IN THE POWER SECTOR

The amine solvent-based post-combustion capture process demonstrated at Boundary Dam 3 (Shell Cansolv technology) and Petra Nova (Mitsubishi) is currently the leading technology for application of CO₂ capture to power plants (IEAGHG, 2015; NETL, 2020). Although using different solvent formulations and process designs, both these technologies essentially introduce cooled flue gas (with SO_x, NO_x, and particulates removed) to a large absorption column in which CO₂ is removed by a liquid solvent (Figure 32). The solvent is then sent to a stripper column where it is heated – using steam from the power plant itself or a separate cogeneration unit – to release a pure stream of CO₂. Other major

suppliers of this kind of technology include Fluor (Econamine FG Plus), Linde (BASF Blue), ION Clean Energy (ALAS), and Carbon Clean (CDRMax).

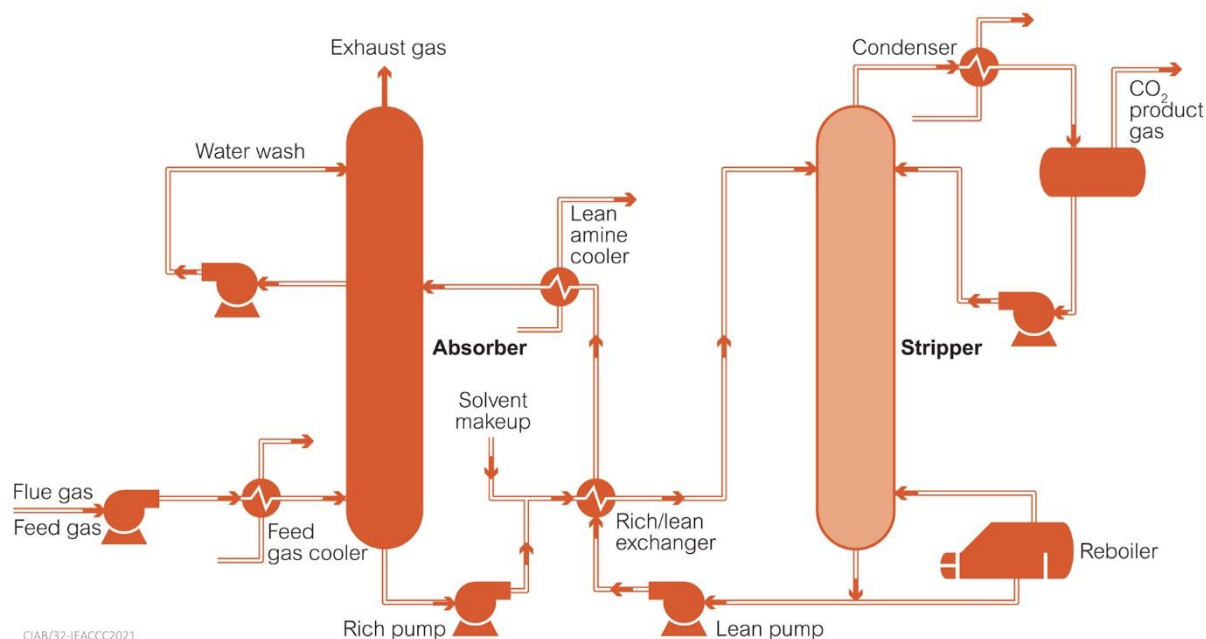


Figure 32 Schematic of a solvent-based post-combustion capture process of the kind used at Petra Nova and Boundary Dam 3

Post-combustion CO₂ capture technology can either be incorporated into the design of new power plants or retrofitted to existing units. Given the large size (>2 TW) of the existing global coal fleet, retrofit applications have tended to attract the most attention, but the technical feasibility and cost of retrofit can depend to a great extent on various characteristics of the target plant. In addition to basic requirements for sufficient space and ideally, good existing pollutant controls, there are considerations about how best to thermally integrate the capture plant with the existing coal plant. In North America there is interest in minimising interference with the power plant steam cycle by sourcing power and steam from a dedicated gas-fired cogeneration unit (as used at Petra Nova). However, Indian retrofit projects would likely adopt the more conventional approach of extracting steam from the crossover between the intermediate pressure and low-pressure turbines (Lucquiaud and Gibbins, 2011). Some modification of the turbine may be required to minimise efficiency losses, but a feasibility study conducted for Canada's Shand plant has demonstrated that retrofit of a modern supercritical steam cycle can be relatively straight-forward (Bruce and others, 2018).

The two completed full-scale CCS power projects were retrofitted to relatively old subcritical power plants (although Boundary Dam 3 was effectively repowered with a new steam cycle), owing to factors such as low-cost fuel, local regulations, proximity to EOR, and depreciated capital. Despite this, on a cost per MWh basis, it is clearly more favourable to target newer, more efficient units for CCS, as such plants have fewer CO₂ emissions to capture for each MWh, and a longer remaining lifetime for the CCS investment to generate value. With this in mind, CCS retrofit projects in India should focus on

the 89.6 GW (130 units) of supercritical or USC plant currently under construction and those which date from 2010 onwards (S&P Global, 2020). Of these, 49 GW will have been commissioned in 2017 or later, so will need to meet the most stringent standards for SO₂ and NO_x – requiring both wet FGD and SCR installation. This will reduce the need for further flue gas clean-up upstream of the capture plant. These priority units could be systematically assessed for retrofit suitability, based on technical and cost criteria, including availability of space at the plant, feasibility of steam cycle modifications, and proximity to storage.

Extraction of steam from the host steam cycle results in a significant efficiency penalty to the overall thermal efficiency of the power plant, combined with a smaller contribution in auxiliary power consumption for pumps and fans associated with the capture plant. This penalty is generally estimated to be about 7–10 percentage points, or a 25–33% relative reduction, depending on the initial plant efficiency (NETL, 2015). This loss of power output and additional coal consumption per MWh is often regarded by policy makers in growing economies as a major barrier to power plant retrofits; this is particularly true for India, given the country's history of chronic power shortages and insufficient domestic coal production (Tongia and others, 2020). However, this context is changing, as India's drive to expand power generation capacity over the past ten years has resulted in sufficient capacity for the medium term, and load factors for many coal plants are expected to remain low due to ambitious renewable deployment. Furthermore, introduction of CO₂ capture to a USC plant with around 45% efficiency will result in a net efficiency of over 35%, which is still competitive relative to the existing subcritical fleet.

Any new coal power plants deployed in India (most likely from 2027 onwards) should clearly be built as 'capture ready' – namely, with modification for steam extraction in-built, sufficient space for capture plant, and proximity to storage (IEAGHG, 2007; Gibbins and others, 2013). In addition to new USC or AUSC units, IGCC or related syngas-based generation units may also be a highly suitable capture-ready option, given the growing focus on gasification described in Section 5.6.

Various technology options exist for post-combustion capture which could provide alternatives to the solvent-based processes described above, including processes based on solid sorbents and membrane separation (Lockwood, 2016). However, these technologies have yet to be demonstrated at full scale for a power plant, with both sorbent and membrane systems currently trialled at scales of around 10 MWe equivalent. Both alternatives offer potential advantages over solvent-based systems, particularly with respect to much lower water consumption, while membrane-based systems do not require steam extraction from the plant (instead using electrical power for vacuum pumping). These characteristics may prove advantageous in the Indian context. A 400 MW scale demonstration of MTR's membrane-based system is planned at Dry Fork power plant, Wyoming, representing a potentially significant step towards commercialisation of this technology (Freeman and Merkel, 2020).

5.5.1 Cost of CCUS on Indian coal plants

Many cost analyses for the application of CCUS to coal power plants have been conducted, but a much smaller number are specific to the Indian context. Table 20 summarises some of the literature from the past decade which has looked at CCUS costs in India, either for retrofit to specific coal power plants, retrofit to a generic (usually high efficiency) plant, or a new efficient plant with in-built CCUS. The wide range of cost results obtained is indicative of the high sensitivity of such analyses to input parameters, the diversity of cases studied, and the long time period considered. Several papers have relied on publicly available cost analysis software from Carnegie-Mellon University, known as the Integrated Environmental Control Model (IECM) – a US-focussed analysis which should be applied cautiously in the Indian context.

TABLE 20 REVIEW OF COST ESTIMATES FOR CCUS ON INDIAN COAL PLANT			
Study	LCOE increase	Cost of CO ₂ avoided (US\$/t)	Notes
TERI, 2013	38–47%	34.4 (imported coal) 31.2 (domestic)	Generic SC capture-ready plant using literature review and industry inputs
Rao and Kumar, 2014	71%	36–43	Four subcritical plants selected and modelled with IECM
Viebahn and others, 2014	45–51%	–	CCUS deployment across fleet to 2050 using literature review and expert input
Singh and Rao, 2016	89% (efficient case)	-65	IECM modelling of retrofit of hypothetical efficient/inefficient and young/old plant
Singh and others, 2017	110%	80	IECM modelling of retrofit of 7 subcritical reference plants
IEAGHG, 2018	100–110%	69–71	Translation of detailed engineering study for new USC plant with CCS, using country specific cost factors
Datta and Krishnamoorti, 2019	7%	–	Bongaigon coal plant (Assam) with EOR income

Nevertheless, it is possible to draw some broad conclusions from the literature:

- Recent studies tend towards roughly a doubling of LCOE relative to coal plant without CCS;
- Costs of CO₂ avoided are in the range 60–80 US\$/t; and
- Cases with domestic coal represent the cheaper end of the range.

The 2018 analysis conducted by Amec for IEAGHG took an existing detailed costing of a new USC plant with CCUS in the Netherlands and converted the results to a range of global locations using various assumptions (IEAGHG, 2018). This study is therefore informative for comparing the projected cost of CCUS in India with other locations on the same basis, and it is based on detailed engineering cost data provided by Amec and Shell Cansolv as the capture technology provider. Figure 33 shows

how the LCOE for the base coal plant and CCS-equipped plant varies around the world, including three Indian cases which cover new USC plants on the west coast with: seawater cooling and domestic coal (7); draught cooling tower and domestic coal (7.1); and seawater cooling and imported coal (7.2). It illustrates that the cases using domestic coal are significantly cheaper, but still represent an LCOE increase of over 100% compared to an unabated plant. The Indian cases are lower cost than some of the more expensive locations such as Canada, Australia, and South Africa, but on a par with locations such as Poland, Japan, and Indonesia. While the domestic coal cases have relatively low fuel costs, plant construction costs are relatively high due to the lower productivity factors and high contingencies assumed for construction projects in India.

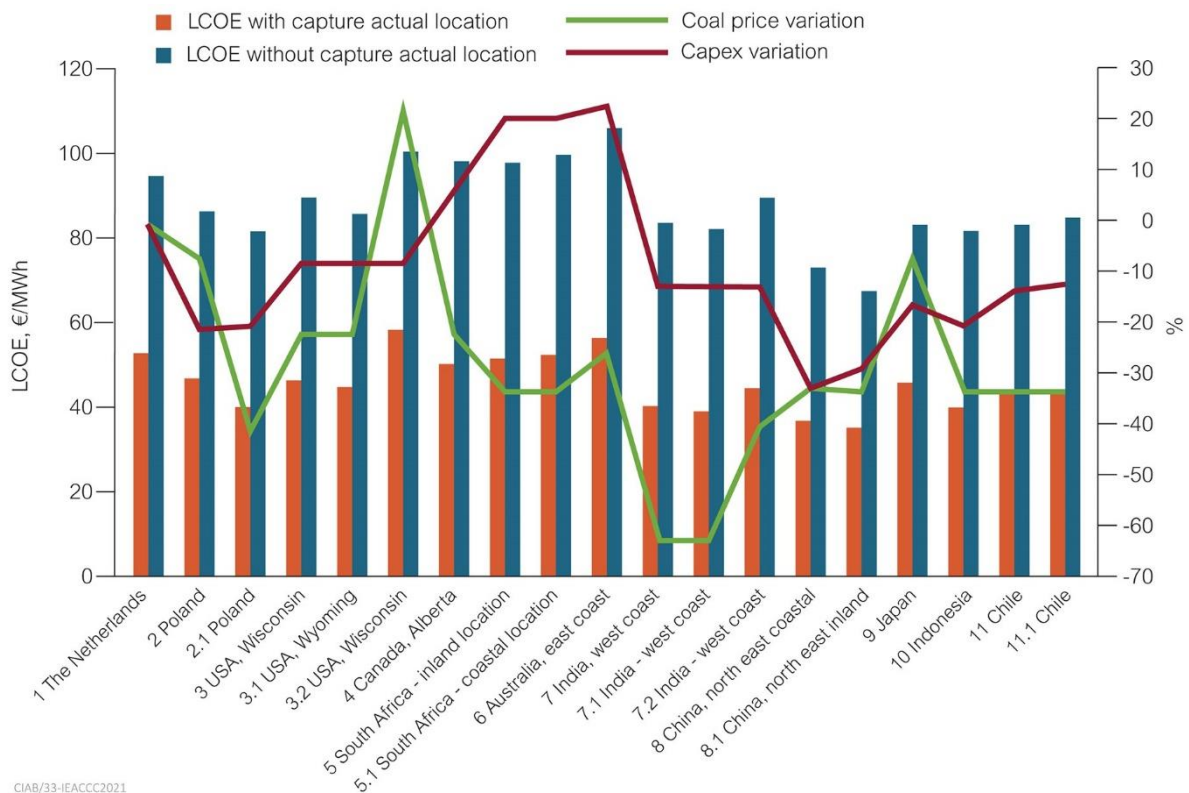


Figure 33 Comparison of LCOE for new USC units with CCS (Shell Cansolv) in a range of global locations (IEAGHG, 2018)

The recent study conducted on the Bongaigon subcritical plant in Assam is also noteworthy, as it obtains a minimal increase in LCOE, which is attributed to revenue from EOR at a nearby oil field, and ready access to local coal (via a conveyor belt system) (Datta and Krishnamoorti, 2019).

Given the relatively high costs identified in the literature to date, it is important to note evidence of marked cost reductions for CCUS-equipped coal plant in the past two years. Building on experience from both the Petra Nova and Boundary Dam 3 projects, the International CCS Knowledge Centre conducted a detailed feasibility study for CCS retrofit to Canada’s 300 MW Shand power plant in 2018, using Mitsubishi capture technology (Bruce and others, 2018). This obtained a CO₂ capture cost of 45 US\$/t, representing a 67% reduction in capital cost over Boundary Dam 3, based on process

improvements, greater use of modular, off-site construction, and capture technology improvements by Mitsubishi. As shown in Figure 34, projected capture costs for the planned wave of US-based capture projects (Project Tundra, San Juan Generating Station, ION C3DC) are also around this level or lower (CIAB, 2019; Kelsall, 2020).

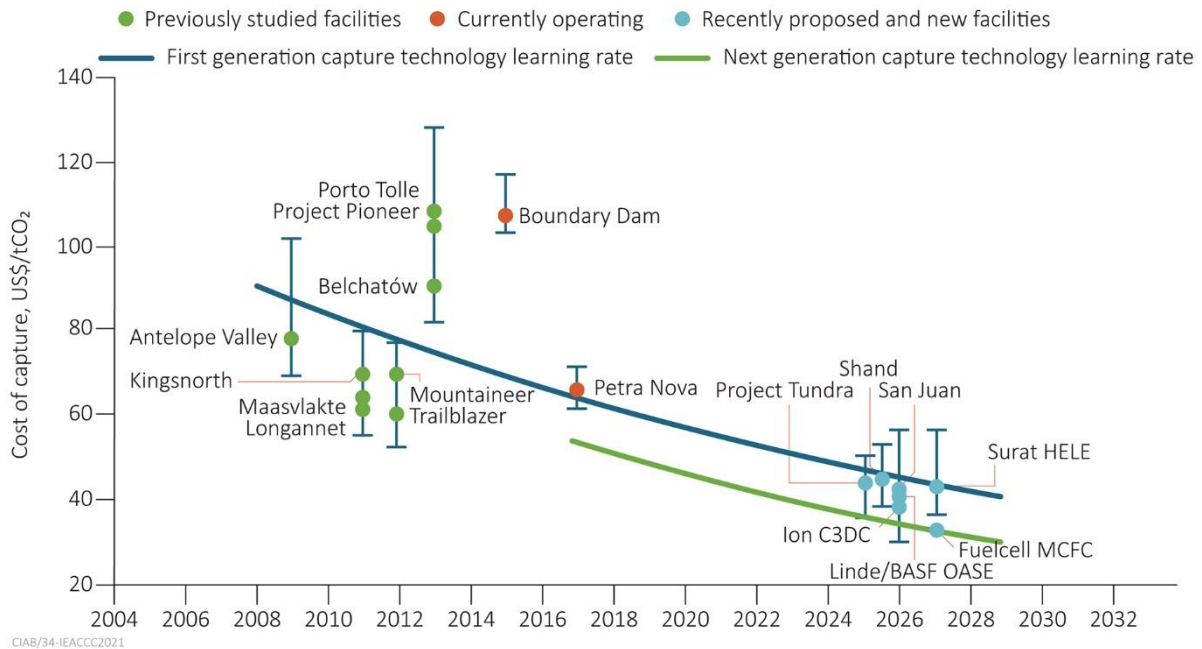


Figure 34 Historical and future cost reductions for CCS (Kelsall, 2020)

5.5.2 Source-sink matching

This section examines what proportion of India’s current SC and USC coal plants have reasonable access to suitable CO₂ storage. For this purpose, we assume a CO₂ pipeline would ideally not exceed 250 km in length, although there are over 7000 km of CO₂ pipeline in use in the USA, and individual CCS projects have commissioned dedicated pipelines of up to 330 km (IEA, 2020c). Figure 35 shows how the potential storage sites discussed in Section 5.3.1 correspond with the locations of India’s most significant coal plants, including all plants with a total capacity greater than 400 MW and any individual units of 200 MW or more (including units currently under construction). Table 21 then assigns suitable storage options within this range to SC and USC plant capacity in each state, dividing plants into geographic clusters where necessary.

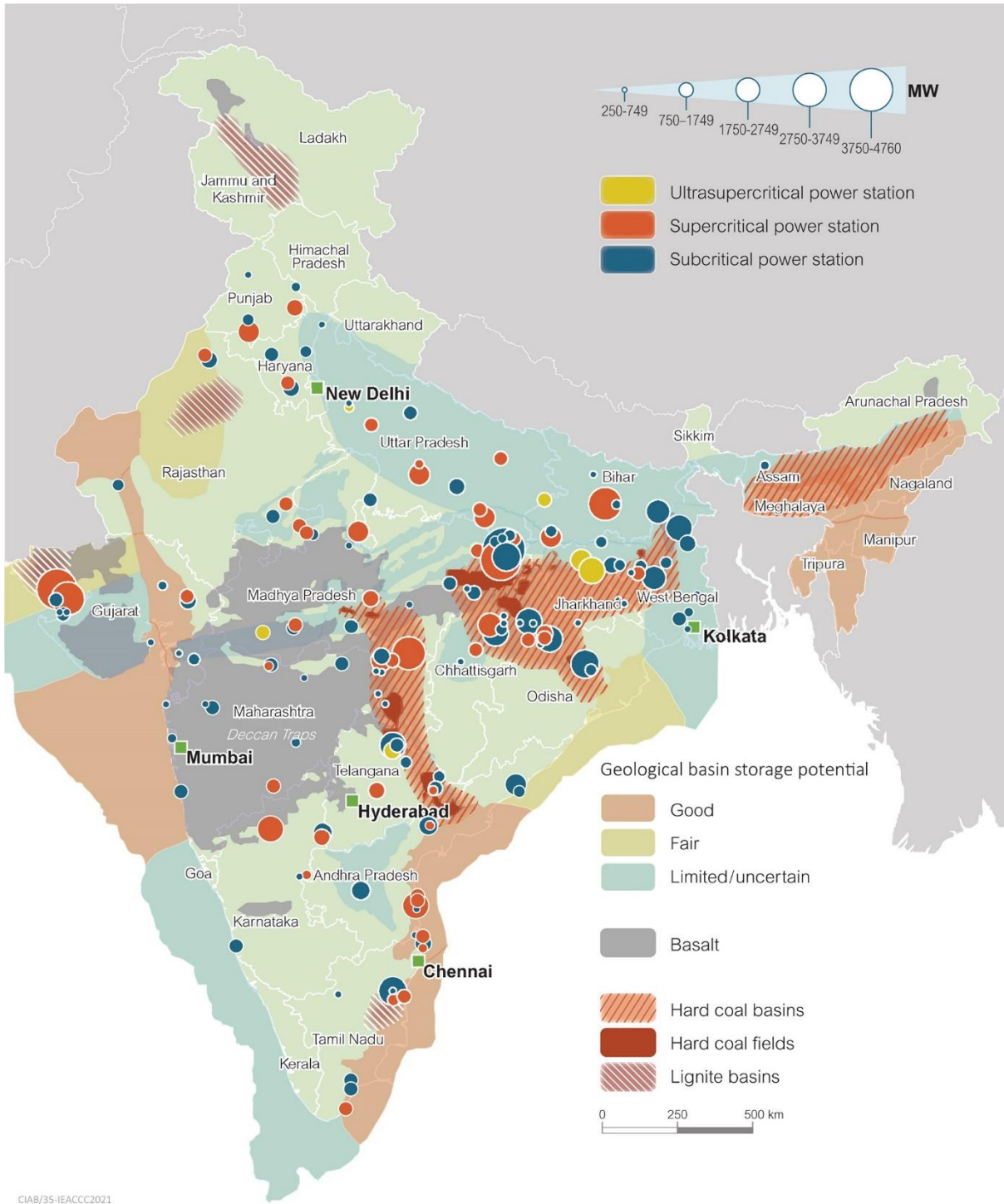


Figure 35 Location of India’s main coal power plants with respect to CO₂ storage options

TABLE 21 STORAGE OPTIONS FOR SC AND USC PLANTS		
State	SC/USC plant capacity	Suitable storage options
Punjab	Southern plant (1.98 GW) Northern plant (1.4 GW)	Bikaner-Nagaur Basin Ganga Basin
Haryana	1.32 GW (1 plant)	Bikaner-Nagaur Basin
Rajasthan	Northern plant (1.32 GW) Southern plant (3.84 GW)	Bikaner-Nagaur Basin Basalt or Vindhyan Basin
Gujarat	Mundra UMPP and Mundra Adani (7.45 GW) 0.8 GW (Wanakbori 8)	Cambay Basin (good EOR potential) or Kutch Basin (closer) Cambay Basin
Madhya Pradesh	Western plant (2.64 GW) Central plant (1.6 GW) Eastern plant (5.28 GW)	Cambay Basin (250-300 km) Basalt or Narmada/Satpura basins Vindhyan Basin or Damodar Valley
Maharashtra	Solapur (1.32 GW) Eastern plant (7.26 GW)	Deccan Traps basalt Deccan Traps or coal seam storage in Wardha or Godavari coal fields
Karnataka	4.7 GW	Deccan Traps basalt
Tamil Nadu	6.24 GW	Cauvery Basin
Andhra Pradesh	5.84 GW (4 plants)	Cauvery Basin
Telangana	Telangana STTP (1.6 GW) Southern plants (2.4 GW)	Deccan Traps basalt Cauvery Basin
Odisha	2.92 GW	Mahanadi basin (~250 km) or Mahanadi Valley coal seam
Chhattisgarh	4.95 GW (3 plants)	Coal seam storage or saline aquifer in Chhattisgarh basin (not promising)
West Bengal	1.2 GW (1 plant)	Damodar Valley (aquifer or coal seam) or offshore Bengal Basin
Jharkhand	4.38 GW	Damodar Valley
Bihar	6.6 GW (3 plants)	Damodar Valley or Ganga basin (closer)
Uttar Pradesh	Southeastern units (3.3 GW) Lalitpur (1.98 GW) Northern plants (7.26 GW)	Damodar Valley Deccan Traps or Vindhyan basin Ganga Basin

From this analysis, some key coal plant clusters emerge which appear to have good potential for accessing storage. Firstly, the 8.25 GW of high-efficiency capacity in Gujarat is noteworthy for its proximity to promising EOR or saline aquifer potential in the Cambay Basin; this includes the very large installations at Mundra UMPP and Mundra Adani. Secondly, over 10 GW of supercritical plant along the South-East coast in Tamil Nadu and Andhra Pradesh could find suitable offshore storage in the Cauvery Basin, with particularly high-density clusters around Chennai and Krishnapatnam.

However, of key importance is developing appropriate storage for the major coal power and other industrial clusters (particularly steel plant) associated with the coal fields in eastern Madhya Pradesh, Jharkhand, Chhattisgarh, and West Bengal. For this region it is imperative to investigate further the saline storage potential of the Damodar Basin (which is regarded as relatively promising by IEAGHG, 2018), as well as pursuing enhanced CBM trials in this region. For plants in eastern Madhya Pradesh, it would also be useful to explore saline storage potential in the Vindhyan Basin.

5.5.3 Drivers for CCUS deployment in the power sector

The value provided by CCUS to any power system can be difficult to discern in the initial stages of decarbonisation, when wind, solar, and hydro power can represent the lowest cost sources of low-carbon power. However, due to the intermittency of these sources, studies of the total system cost have shown that CCUS-equipped power plant eventually forms a key part of the lowest cost pathway to net-zero carbon emissions (Boston and others, 2018; Pratama and Mac Dowell, 2020). This is particularly the case in countries like India, which have a large existing fossil power sector.

In order to adequately express the value of CCUS to power system decarbonisation, it is necessary to implement a form of policy incentive. Regardless of the potential for cost optimisation, the addition of CCUS to a power plant will always represent an additional cost, which should be compensated through some form of revenue stream if the practice is to be commercially viable. There are various possible means of providing such revenue, including (Lockwood, 2017; Kelsall, 2020):

- Enhanced oil recovery;
- Sale of CO₂-based products (CCU), potentially enhanced by credits for low-carbon products (such as California's Low Carbon Fuel Standard);
- Carbon pricing (increases the cost of unabated power plants, theoretically raising power prices in a competitive market);
- Favourable power tariffs for CCUS power plant (such as the Contract for Difference (CfD) mechanism proposed in the UK);
- Priority dispatch for CCUS power plant (applied for Guangdong CCS pilot project in China);
- Direct compensation or tax credit for sequestering CO₂ (such as the 45Q credit in the USA); and
- Portfolio standards – a requirement for low-carbon power in utility portfolios, often driven by a form of tradable certificate (this approach is seen in US states, the UK, and Australia).

The extent to which CO₂ pricing systems (such as a carbon tax or emissions trading) can drive CCUS is a contentious issue. Notable successful examples of this are Norway's Sleipner and Snøhvit projects, which were driven by a relatively high carbon tax for offshore oil and gas production, while the inclusion of CCS at Australia's Gorgon LNG project was essentially required by government. Although some industries have adequate margins to absorb the cost of CCS in this way (without a compensating revenue stream), this is not likely to be viable for the power sector, with its lower, more regulated

income. On the other hand, while unabated fossil power plant remains, carbon pricing in the power sector will act to raise marginal power prices, and can therefore translate to additional income for low carbon plant. This effect is severely dampened, however, when power systems can initially reduce carbon intensity at a lower cost through renewables deployment or coal-to-gas switching. Several planned coal-CCS projects in the EU were not realised due to a combination of low carbon prices (EU ETS) and the ease of coal-to-gas switching in countries with established gas capacity (Read, 2017).

In the Indian context, carbon pricing in the power sector may have more potential to drive favourable power prices for CCS-equipped plant, owing to the relative lack of alternatives to coal power for dispatchable generation. However, given the currently highly regulated nature of the Indian power market, and the higher ‘first-mover’ costs inherent in launching a CCUS industry, this approach is not considered optimum for driving initial CCUS deployment in the sector. Instead, some form of targeted compensation is likely to be required, such as credits for CO₂ sequestered, or a guaranteed power price for CCS-equipped plant. This kind of directed support, in the form of feed-in tariffs and portfolio standards, has already proved successful for driving rapid deployment of renewable energy sources around the world.

India’s coal power plants currently experience low average load factors and this is expected to continue as ambitious wind and solar deployment targets are met. It is therefore possible that priority dispatch for a CCUS-equipped power plant, allowing load factors closer to 90%, could act as a strong financial incentive for initial retrofits. This approach has been used to some extent in China, where the Haifeng power plant in Guangdong was provided with higher operating hours to reward its development of a large CO₂ capture pilot facility (Li, 2017). Although CO₂ capture can be operated flexibly to some extent, more continuous operation would also benefit the process performance, particularly for facilities linked to chemical production through CCU. For larger projects, operating hour incentives would likely require supplementing with a suitable power tariff which, for India’s regulated tariff plants, could be applied through the existing system of benchmarked tariffs; essentially, the additional fuel cost of a CCUS-equipped plant would be passed through to the wholesale tariff.

As India’s electricity market transitions to a more competitive system with an economic-based merit order, support mechanisms for CCUS-equipped power plant can look to early experience with incentives developed in markets such as the USA and the UK. The USA’s expanded 45Q tax credit system is significant in offering compensation directly linked to CO₂ storage, with a credit of up to 35 US\$/t for suitably certified EOR operations or CO₂ conversion, and up to 50 US\$/t for saline aquifer storage (eligible projects must commence construction by the start of 2026). This effective positive cashflow associated with generation can also act to improve the position of CCS-equipped plants in the merit order. Given India’s much more limited ability to absorb reduced tax revenue, adopting such a system may initially require international support. A form of tax credit incentive offset by revenue from coal-based chemical production is outlined in the following section.

In the UK, the CfD mechanism guarantees a minimum ‘strike price’ for power from various clean energy technologies, based either on a bidding process or bilateral negotiation. The difference between the average market power price and the strike price is compensated through a surcharge on all consumers. Following the failure to establish an acceptable strike price for early CCS projects, a revised proposal has been developed based on a ‘dispatchable CfD’ which attempts to value the flexible nature of CCS power plant. This variation would include compensation for fixed costs and pass-through of transport and storage costs (CAG, 2019).

As discussed, the sale of EOR-derived oil or CO₂-based products are the most straight-forward means of deriving income from CO₂ capture projects in existing markets. The value of this activity to the power plant can be further enhanced through incentives for low-carbon or domestic hydrocarbon products, as exemplified by the tax benefits for EOR outlined in Section 5.3.2. CCU-derived chemicals can also be supported through product standards, which can be most readily applied through government procurement policy, or tradable credits for low-carbon products, as demonstrated by California’s Low Carbon Fuel Standard. However, these incentives rely on a robust framework for assessing the carbon footprint of such products.

Regardless of the incentive mechanism implemented, financing CCUS development presents a major challenge for a developing country such as India and is likely to require international support. This could be founded in the Paris Agreement’s obligation for developed countries to assist with financing climate mitigation initiatives in lower-income countries. There has already been growing international collaboration with India on CCUS research, through bilateral partnerships such as the US-India Strategic Energy Partnership, and multilateral funding initiatives such as the EU ACT programme (PTI, 2020). The Asian Development Bank have also been active in supporting CCUS development in Asia since 2009, when it established a Carbon Capture and Storage Fund with Australia, later joined by the UK (ADB, 2020). Although it is considered a priority country for this fund, there are currently no active projects with a specific focus on India. Full-scale demonstration of CCUS in India may require direct support from OECD countries with a strong interest in progressing the technology, such as the USA, UK, Australia, or Japan. However, given the ultimate failure of several such bilateral initiatives targeting CCUS demonstration in China, it is clear that committed support and a long-term vision for the technology is a prerequisite (Lockwood, 2017).

5.6 COAL GASIFICATION AND THE METHANOL ECONOMY

Based on a concept developed by NITI Aayog, in 2016 the Government of India launched an initiative known as ‘The Methanol Economy’, aimed at increasing India’s domestic production of liquid fuels and chemicals through the gasification of domestic coal (Saraswat and Bansal, 2017). Like policies to drive greater use of EOR and CBM, the scheme is in response to growing dependence on oil and gas imports, coupled with very low growth in domestic production. Methanol is seen as a highly viable alternative or supplement to existing transport fuels, given its high octane value and low NO_x and particulate

emissions. China represents a key reference for the Methanol Economy, as the country produces 70% of its methanol from coal, and in 2016, blended around 21 Mt of methanol with petrol for transport fuel. India's current methanol consumption (~2 Mt in 2018) is around 80% imported, with domestic production largely provided by the fertiliser industry using imported natural gas as a feedstock (Peter, 2020).

In 2020, NITI Aayog and the GoI set a target of gasifying a cumulative total of 100 Mt of coal by 2030, along with the intention to build at least five coal-to-methanol plants in the near-term (Wang, 2020). In order to help drive these developments, the Government granted a concession of 20% on coal revenue share for gasification projects. In 2019, a regulatory framework was proposed for blending methanol with transport fuel, and the Methanol Economy initiative plans to initially target cargo vessels for transition to methanol (Saluja and Sharma, 2019). Currently, the only coal gasification plant in India is operated at Jindal Power and Steel's Angul plant (for direct-reduction blast furnaces), and there is another major project under construction at the Talcher Fertiliser plant, constituting a joint venture between Coal India, GAIL (a state-owned natural gas transmission company), and two fertiliser companies. Coal India is at the forefront of other developments, having put out a tender to develop a 1.5 Mt/y gasification plant at the Dankuni coal complex in West Bengal. The company plans to invest Rs 25,000 in six other gasification projects between 2022 and 2026, with a total capacity of 6 Mt/y of coal (Sharma, 2020). These sites are likely to be focused in West Bengal and Jharkhand, where state governments have allotted dedicated coal mines. Technology provider Air Products has stated its intention to invest up to US\$10 billion in coal gasification in India (Chatterjee, 2020b).

NITI Aayog have also implemented a coordinated R&D programme, aimed at further developing indigenous technology for gasification of high-ash coal. This builds on technologies developed by BHEL, Thermax, and IIT Delhi (NITI Aayog, 2020)

The strong policy drive and investment in coal gasification establishes a promising environment for CCUS, as CO₂ capture from gasification plants can be achieved at relatively low cost compared to conventional power plants. As noted, several of China's early medium-scale CCUS facilities have been associated with coal gasification plants, such as the Yanchang Integrated CCUS project (Lockwood, 2018). While power production is not explicitly envisaged as part of the new gasification sites, there is considerable potential to develop polygeneration plant, incorporating integrated gasification combined cycle or even hydrogen fuel cell technology with production of methanol or other chemicals.

India-based engineering consultancy firm Dastur have laid out a vision for multiple gasification clusters around the country, including production of hydrogen, methanol, ammonia, direct-reduced steel (using coal-derived syngas), and power (roughly 1.5 GW of syngas or hydrogen-based capacity per cluster). The company see CCUS as an essential means of ensuring the long-term viability of these clusters in a low-carbon future, and propose a tax credit-based system as a means of supporting CCUS

(see Figure 36). While tax revenue from chemical and fuel production is eventually expected to be sufficient to support the cost of CCUS incentives, an initial fund would seek international investment. Shallow offshore CO₂ storage in West Bengal is seen as a promising option for the clusters in Eastern India, while there is also a possibility for shipping CO₂ from the Ports of Haldia and Paradip to EOR operations on the West Coast (Mukherjee, 2019, 2020).

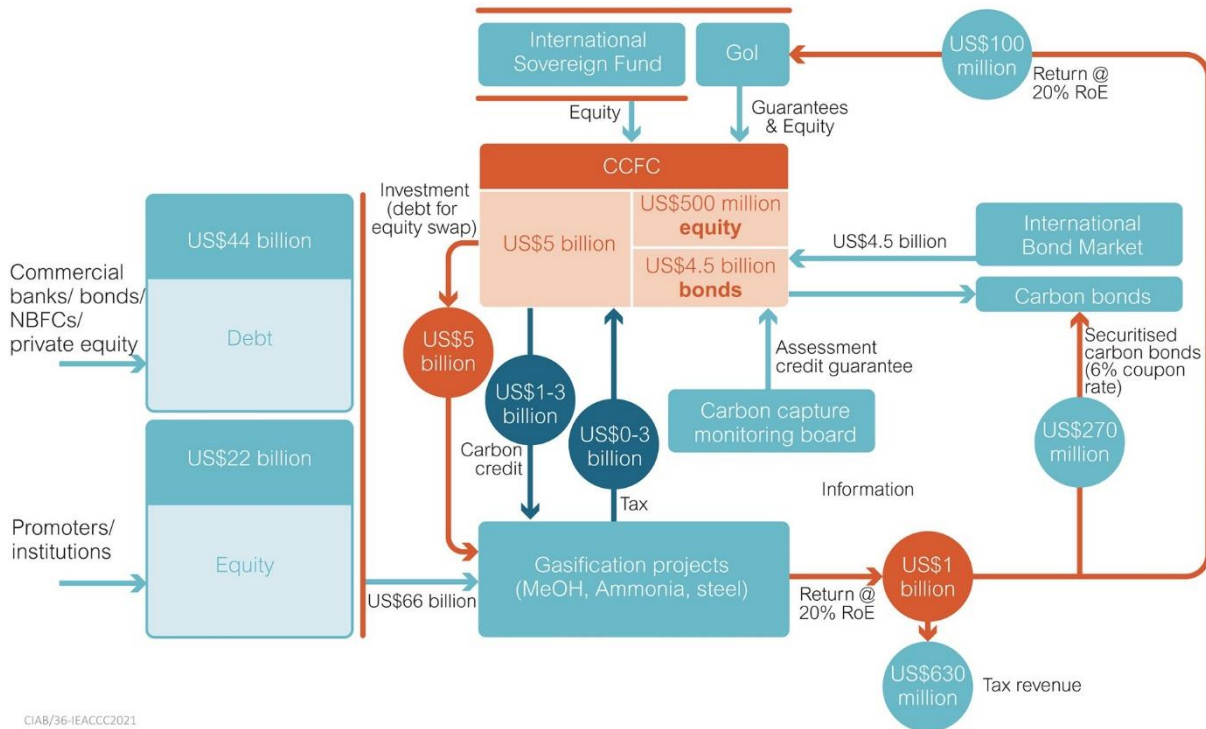


Figure 36 A financing model for gasification-based CCUS in India, based on a carbon credit finance corporation (CCFC) with initial investment from international lenders (Mukherjee, 2019)

5.7 RECOMMENDATIONS

Development of CCUS in India has progressed slowly to date, due in large part to perceptions that a financially stretched power sector cannot bear the additional cost and efficiency penalty, and that geological storage options are limited. However, recent rapid growth in coal power capacity and more ambitious climate targets present a more favourable environment for CCUS development, while there are indications that early approximations of geological storage potential have unnecessarily dampened interest in the technology. We propose the following recommendations for driving CCUS in India’s coal power sector:

- A more detailed assessment of geological storage potential is urgently needed, including characterisation of saline aquifers in coal-producing regions, such as the Damodar Valley;
- The existing fleet should be assessed for retrofit suitability, potentially starting with centrally owned supercritical and USC units;
- Priority dispatch for CCUS-equipped coal plant, together with tariff pass-through of additional coal costs, could act as an incentive for early projects;

- EOR and CO₂ conversion technologies can also play a role in kickstarting first-mover projects, supported by incentives for domestic, low-carbon products;
- New coal plants in India should be capture-ready – including an assessment of nearby CO₂ storage options;
- The Methanol Economy represents an ideal opportunity to develop CCUS clusters associated with gasification clusters which can incorporate both production of high-value products and power;
- The GoI should coordinate an integrated, cross-sectoral technology demonstration strategy among relevant PSUs, such as Coal India, NTPC, ONGC, and GAIL;
- Initial financing of CCUS deployment will likely require international investment, as well as international support in the form of technical capacity building, storage assessment, and knowledge sharing; and
- CCUS should be explicitly included in India's international climate commitments.

6 COAL-FIRED POWER TO 2040

This chapter identifies two pathways for high efficiency, low emissions (HELE) coal-fired power in India to 2040. The pathways consider the age, operation, and overall efficiency of the fleet that operates today and model it to reflect the need to reduce emissions of CO₂ and to increase output per unit of coal. It goes beyond the current building programme which includes 32 GW of new plants scheduled to come online during 2020-23. The pathway takes a fast-track approach to decommissioning older, less efficient subcritical units and replaces or upgrades them with the equivalent HELE capacity operating at a lower level of CO₂/kWh of output. In this chapter, it is assumed that all new plants are equipped with appropriate technologies that capture emissions of pollutants PM, SO_x, and NO_x to comply with prevailing emission standards

Firstly, the rate of growth of coal-fired generating capacity is defined by the future demand for thermal power in India. NITI Aayog published Draft National Energy Policy in 2017 (NITI Aayog, 2017a) which uses 2012 as the base year and then projects coal-fired power generation to 2022 and 2040. This document served as a plausible basis for the IEACCC high capacity pathway, although it was not adopted formally by the GoI. A lower trajectory for coal power is taken from the October 2020 edition of the IEA World Energy Outlook (WEO). This includes a revised Stated Energy Policy Scenario (STEPS) for India to 2040 which reduces the role for coal compared to both the 2019 STEPS and the 2017 NITI Aayog Ambitious Scenarios.

6.1 NITI AAYOG AMBITIOUS SCENARIO

In the NITI Aayog Ambitious Scenario, coal-fired generation reaches approximately 1980 TWh in 2040 for plants without CCS (increasing to roughly 2120 TWh when including plants fitted with CCS). This scenario was developed in the context of a large increase in alternative energy supplies such as solar PV, wind, hydro, gas, and nuclear (*see* Figure 37). In this scenario, around 66%, or 832 GW, of India's generating capacity was based on non-fossil fuel sources and accounted for 47%, or 2224 TWh, of India's domestic power production in 2040. The IEACCC path uses the NITI Aayog Ambitious Scenario as a ceiling for coal-fired power capacity and does not exceed its projections while also taking into account the recent trends in coal generation due to COVID-19 and other economic factors that have slowed the growth in power demand. The NITI Aayog Ambitious Scenario for 2040 does not completely align with more recent projections from CEA published in early 2020 (*see* Figure 10 on page 41) where the outlook assumes a lower growth from coal-fired reaching 1254 TWh by 2029-30.

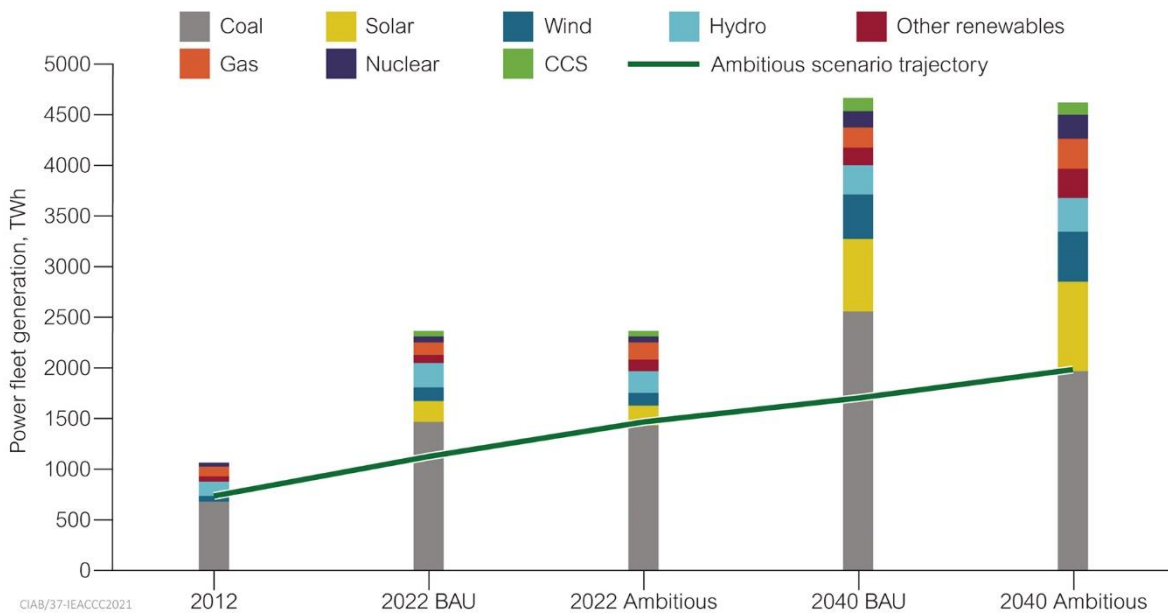


Figure 37 Power generation scenarios for 2022-40, TWh (IEACCC based on NITI Aayog, 2017a)

6.1.1 IEACCC simulation applied to high capacity scenario

In this section the IEACCC simulation for HELE coal power is based on the demand to 2040 projected by NITI Aayog (2017). In the model, coal does not replace other forms of power generation, but the investment cycle for coal power is accelerated to replace older, less efficient units with either new or modernised existing ones. A decommissioning profile for existing, and almost entirely subcritical plants, is created to build a trajectory for new HELE capacity. Currently, some 170 GW of 250 GW of coal capacity uses older subcritical technology.

As part of this regime to accelerate the deployment of HELE, the existing fleet is taken out of service on a 25-year retirement cycle which reflects the CEA National Electricity Plan (2018) identification of 22.7 GW coal capacity that could be retired between 2017-22, and a further 25.6 GW between 2022-27. This gives a total retirement schedule of roughly 48 GW and is based on plants aged 25 years or more (CEA, 2018a). The IEACCC's own appraisal of the fleet based on S&P Global World Electric Power Plants Database (WEPP) (S&P Global, 2020) was in broad agreement and identified 55 GW of capacity that would reach 25 years in the period 2020-27. The difference between the CEA and IEACCC retirement figures could be due to the CEA's focus on utility generators only, while the WEPP database includes both utility and non-utility generators.

In the IEACCC projection subcritical plants are replaced with SC and USC technologies between 2020-30. From 2030 onwards, next-generation USC technologies, such as AUSC or equivalent high-efficiency technologies, are assumed to be commercially available and become the units of choice to 2040.

In the simulation, the IEACCC calculated that a total of 122 GW of subcritical plants would be due for decommissioning over the forecast period to 2040. Three quarters of the plant closures occur in

2030-40. The IEACCC projection supports the assertion from the CEA (2018a) that there is relatively little need for additional new plant beyond those already in construction until 2027. However, the demand for electricity differs in different regions and while one region may be in surplus, others may be in deficit. Nonetheless, from a nationwide perspective, an increase in coal capacity becomes necessary after 2026 assuming electricity demand resumes a moderate rate of growth from 2021 onward.

190 GW OF HELE PLANTS COULD BE ADDED BY 2040 –
INCLUDING 54 GW OF CONVENTIONAL SUPERCRITICAL
AND ULTRASUPERCRITICAL CAPACITY BY 2030 AND
136 GW OF ADVANCED 50% EFFICIENCY
TECHNOLOGIES BETWEEN 2030-40

In summary, the results suggest that upgrading or replacing older subcritical plants, combined with growth in demand for coal-fired power projected by NITI Aayog means that approximately 180 GW of HELE plants could be added in the period to 2040, as follows:

- 58 GW of conventional SC and USC is commissioned in 2027-30, to replace retiring units; it could also include upgrades to some existing subcritical plants; and
- 136 GW of advanced technologies such as AUSC or USC capable of around 50% efficiency (LHV) are brought online from 2030 onwards.

The simulation demonstrates a feasible strategy that could lead to a significant improvement in power plant efficiency and stack emission performance in the Indian coal fleet by maximising the deployment of state-of-the-art technology over the next 20 years.

6.1.2 Plant load factors

The assumptions for plant utilisation for the various HELE technologies are some of the most complex considerations in the simulation. Since 2007, the plant load factor (PLF) of the coal fleet has gradually fallen from roughly 80% in 2007 to 60% in 2019. The latest PLF for the period April to August 2020 showed thermal plants operating at 48.5% (IEACCC, 2020; CEA, 2020c). At the time of preparing this report (November 2020), the impact of the COVID-19 pandemic on the power sector remained uncertain, but it has already disrupted the historical growth trend of coal-fired power generation. From 2008 to 2018 the average annual growth of coal-fired power was 7%, despite the ongoing decline in the PLF. However, in 2019 coal-fired output fell 2% followed by a further 13% in the first half of 2020 (compared with the same period in 2019) reaching an estimated 990 TWh.

The IEACCC simulation assumes a recovery in electricity demand after 2020 and consequently expects the PLF of existing plants to rebound as plants ramp up to meet short to medium-term recovery in electricity demand. Any spare capacity that exists in the fleet is assumed to be utilised first as it is considered to be more cost-effective than building new capacity to meet the growing demand. This does not preclude regions that are deficient in power supplies from investing in new coal-fired capacity however, but circumstances will vary on a regional basis.

Nationwide, a possible slowdown in investment could occur which fits with the Indian government findings that there was little need to commission net-additions of coal-fired capacity, beyond those currently under construction, until 2026. Despite the apparent absence of need for new greenfield projects, brownfield projects such as upgrades or replacement of major components could be a strong area for investment for equipment suppliers in the meantime (see Chapter 3).

After 2026, continued growth in electricity demand from thermal sources in the NITI Aayog Ambitious Scenario could push the coal fleet to operate at higher loads due to the contraction of the subcritical fleet from 145 GW to 123 GW as plants reach 25 years of service. Beyond 2026, the need for new net-additions of thermal capacity emerges. Modern SC and USC units are likely to dominate the order books as Government policy and climate goals specify SC as a preferred minimum requirement for new coal capacity (see Chapter 2).

Over the long term, a degree of flexible operation is expected from coal plants resulting from the increased penetration of variable renewable power. The CEA conducted research titled ‘Report on optimal generation capacity mix for 2029-30’ to establish a balanced and reliable supply of electricity at least cost while integrating increased amounts of VRE. The hourly generation dispatch for a period in October was considered the most demanding time for the Indian grid in terms of both volume and variability (CEA, 2020b). The CEA observed that coal capacity ran at a minimum technical load (MTL) of 55% during the hours of peak output from solar plants. As solar output recedes, the grid operator would be forced to draw power from thermal power, battery storage, and pumped hydro. Even with non-fossil fuel storage capabilities, the CEA estimated that the daily PLF of coal capacity would still achieve 72.6% as illustrated in Figure 38 (CEA, 2020b). The CEA recommended that during periods of high seasonal output from renewables and lower demand, routine maintenance of coal plants could be carried out.

THE CEA ANALYSIS FORECAST COAL-FIRED CAPACITY TO REACH 266.9 GW BY 2029-30 (CEA, 2020B). THIS PROJECTION IS BROADLY CONSISTENT WITH THE IEACCC SIMULATION WHICH PROJECTS CAPACITY TO REACH 272.7 GW BY 2030.

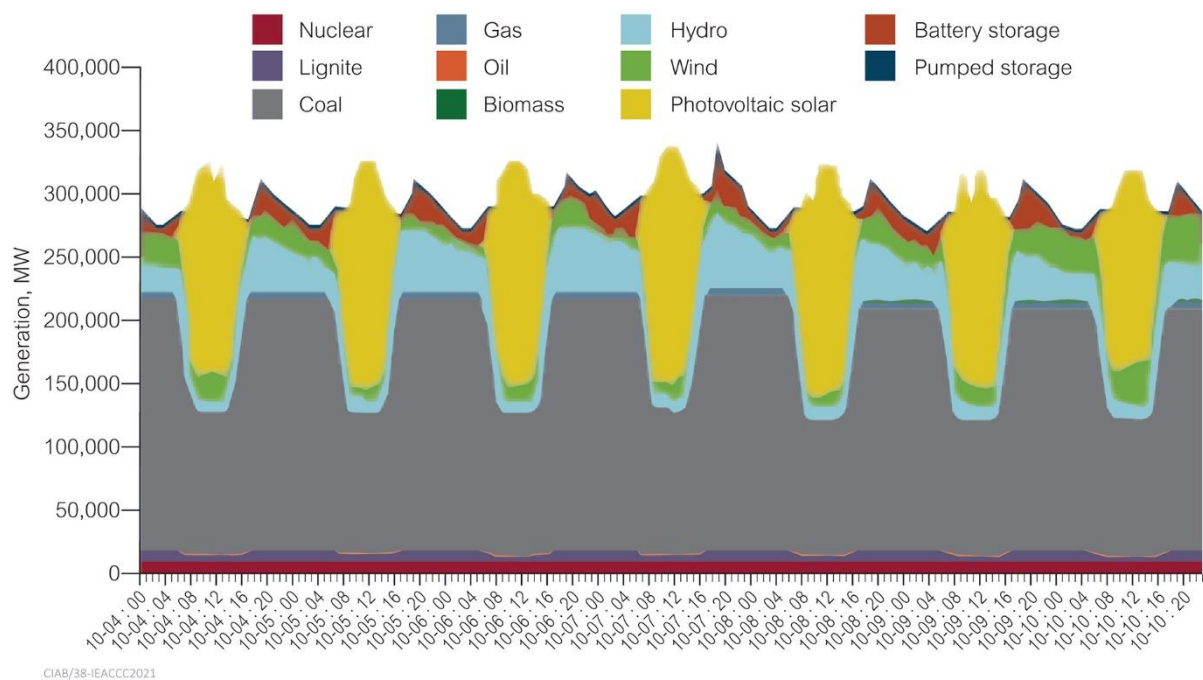


Figure 38 Hourly generation dispatch for the peak days of 4-10 October in 2029-30, x-axis labels month-date: hour (CEA, 2020b)

In the IEACCC simulation, high utilisation is assumed for SC and USC units; financial stresses faced by plant generators and distribution companies means operating capital-intensive investments at low loads may not be desirable if the investment cycle is limited to 25 years or less. Cost recovery required to repay debt and equity returns is important when planning finance for new power plants thus, market mechanisms and regulations could be considered to prioritise HELE plants in the merit order over less efficient and higher emitting sources.

6.1.3 Estimating CO₂ emissions

Annual CO₂ emissions from the coal-fired fleet are derived from emission factors based on grammes of CO₂ per kWh combined with the generating output for that year. The emission factor used depends on the coal combustion technology as shown in Table 22.

TABLE 22 HELE EFFICIENCY AND EMISSION FACTOR ASSUMPTIONS (IEACCC, 2020; PANDE AND DAHIYA, 2019)		
	Efficiency (LHV), %	Emissions, gCO ₂ /kWh
Existing subcritical	36	933.5
Existing SC (including under construction)	40	836.5
Existing USC (including under construction)	43	775.2
New SC (built after 2025)	41	815
New USC (built after 2025)	44–45	739.8–757
USC and AUSC* (built after 2030)	50	667
* based on converting 46% HHV to 50% LHV based on Pande and Dahiya (2019)		

Efficiencies for subcritical stations are based on IEACCC calculations derived from historical fuel input and power output data obtained from the IEA Data Services (2020). Efficiencies for all SC and USC plants are based partly on design efficiencies of existing plants or those expected to commence operation in coming years (Pande and Dahiya, 2019). Whether a unit achieves and maintains its design efficiency depends on site specific factors. In the IEACCC simulation, efficiencies and emission factors remain fixed for the forecast period for simplicity, but there are also practical reasons. Typically, the efficiency of a unit may decline with age, but performance is assumed to be maintained, thus enabling the simulation to focus on the effects of displacing older subcritical units with newer HELE technology. Furthermore, it is good practice to ensure the design efficiencies of plants throughout their life, or even to increase them over time using upgrading methods described in Chapter 3.

So-called ‘flexing’ and two-shifting can reduce efficiency. However, a drop in efficiency can be largely offset by higher efficiencies during periods of higher loads. Due to the complexity of diurnal variation and the output of VRE, it is beyond the scope of this report to ascertain the overall effect on efficiency averaged over the entire Indian fleet and more research would be required in this area. However, studies carried out by NTPC on their own units showed that an individual SC plant operating at 80% load could experience an increase in heat rate if the same unit operated at 50% load. For illustrative purposes, this would equate to an efficiency decrease from, say, 41% (LHV) to 38.5 % (LHV). Nonetheless, the IEACCC simulation assumes a plant operating regime which strives for best practice maintenance and upgrades carried out to ensure optimum performance is achieved under both baseload and flexible conditions, thus maintaining design efficiency throughout the life of the fleet. The subcritical fleet is kept at the current average efficiency of roughly 36% efficiency over the forecast period while HELE plants operate at high loads.

6.1.4 Results

A SHIFT TO HELE PLANTS WITH SOME CCS COULD
AVOID ROUGHLY 4300 MtCO₂ BETWEEN 2021 AND 2040
EQUIVALENT TO 215 MtCO₂/y

Figure 39 illustrates the impact on the fleet’s CO₂ emissions as the fleet modernises over time with a greater shift to more advanced HELE technologies. As described in the NITI Aayog Ambitious Scenario, coal-fired power generation increases to approximately 1980 TWh by 2040 (2100 TWh including thermal plants with CCS) an increase of just under 1000 TWh from 2020. This increase in coal-fired generation occurs concurrent with a substantial rise in renewable energy (see Figure 39).

A consequence of the rise in generation is that CO₂ emissions also increase, rising 70% between 2020-40. However, the growth in electricity production is proportionally higher, and the switch to HELE technology brings the emission factors down from 972 gCO₂/kWh in 2019 to 752 gCO₂/kWh

by 2040 (see Table 24). The adoption of CCS is considered to start after 2030 and is limited to the 26 GW modelled in the NITI Aayog Ambitious Scenario, assuming the CCS is fitted to coal power plants. The addition of CCS helps reduce the unit emissions further to 693 gCO₂/kWh. In terms of absolute emission, the switch to SC and USC plants results in a levelling-off of CO₂ emissions after 2030, and a decrease after 2035, thus arresting any further increase in emissions, even as generating output continues to increase over the forecast period.

It should be borne in mind that these long-term outlooks constitute potential pathways that can be achieved if the appropriate policies and supportive mechanisms are in place, which are discussed in Chapters 2 and 3.

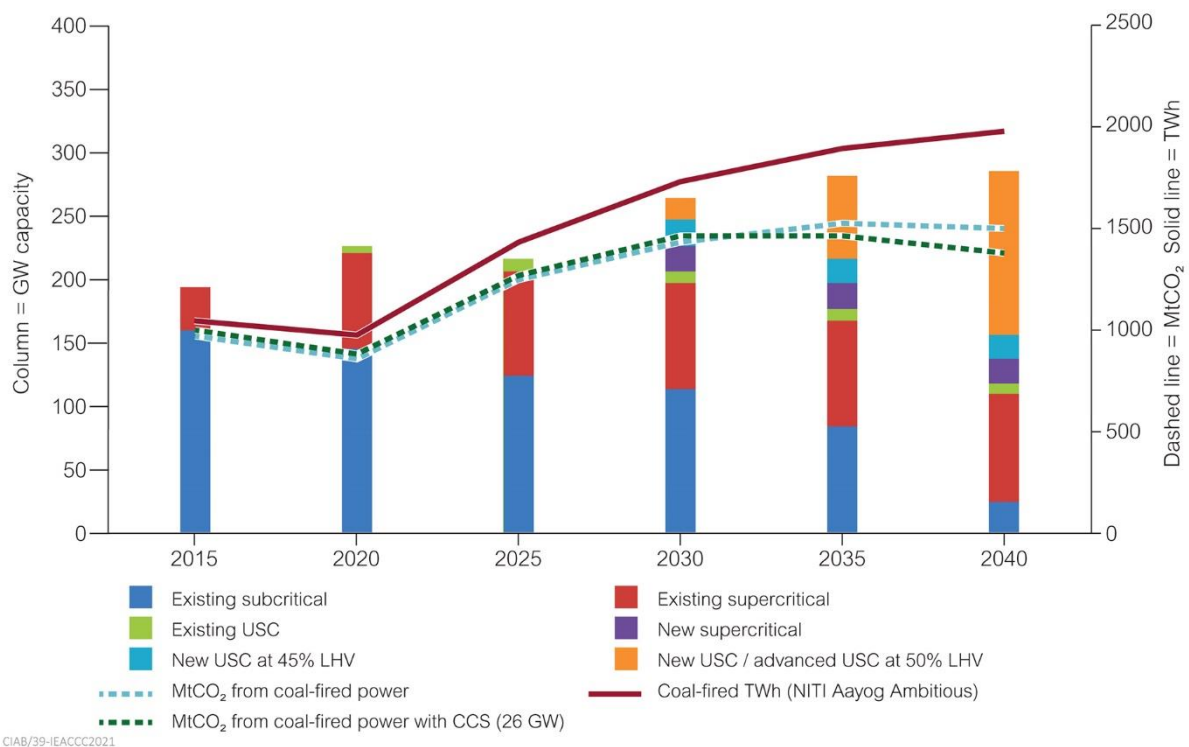


Figure 39 IEACCC projections based on NITI Aayog Ambitious Scenario

Table 23 and Table 24 give the detail for the results shown in Figure 39.

TABLE 23 COAL POWER CAPACITY GROWTH SCENARIO TO 2040 BY TECHNOLOGY, GW (IEACCC, 2020)

	2015	2020	2025	2030	2035	2040	Change 2020-40
Existing subcritical (including current construction)	159.6	145.1	122.9	113.5	82.8	23.2	-121.9
Existing supercritical (including current construction)	34.3	77.2	84.5	84.5	84.5	84.5	7.3
Existing ultrasupercritical (including current construction)	0.0	4.9	9.3	9.3	9.3	9.3	4.4
New supercritical (beyond current construction)	0.0	0.0	0.0	23.2	23.2	23.2	23.2
New USC at 45% LHV (beyond current construction)	0.0	0.0	0.0	19.3	19.3	19.3	19.3
New USC at 50% or AUSC at 50% LHV	0.0	0.0	0.0	19.0	73.7	136.2	136.2
Total All Coal	194	227	217	265	272.7	299.6	72.6
MtCO ₂ from coal-fired power	998.0	880.5	1360.3	1569.7	1619.1	1592.4	711.9
gCO ₂ /kWh from coal-fired power	967	886	878	849	801	752	-134
Coal-fired TWh (NITI Aayog Ambitious)	1032.1	990.7	1453.5	1731.9	1895.0	1984.1	993.4
MtCO ₂ from coal-fired power with 26 GW equipped with CCS	998.0	880.5	1360.3	1559.2	1552.5	1467.2	586.7

Technology	2015	2020	2025	2030	2035	2040
Existing subcritical (including current construction)	809	521	813	730	506	135
Existing supercritical (including current construction)	223	446	666	650	634	618
Existing ultrasupercritical (including. Current construction)	0	27	71	70	68	66
New supercritical (beyond current construction)	0	0	0	148	152	152
New USC at 45% LHV (beyond current construction)	0	0	0	167	173	173
New USC at 50% or AUSC at 50% LHV	0	0	0	83	489	974
Total All Coal (NITI Aayog = 2121 TWh)	1032	994	1453	1848	2021	2118

To place the simulation in context, if India's investment cycle for coal-fired power plants were typified by a 40-year plant life, then the unabated fleet would be locked into a higher level of CO₂ emissions (see Figure 40). Under a 40-year investment cycle just 46 GW of older plants are retired between 2020-40, compared with 122 GW under the 25-year cycle. The accelerated investment cycle leads to a massive investment opportunity for the power industry to manufacture and supply more HELE capacity, creating employment and developing infrastructure which could amount to US\$228 billion (IEACCC estimates).

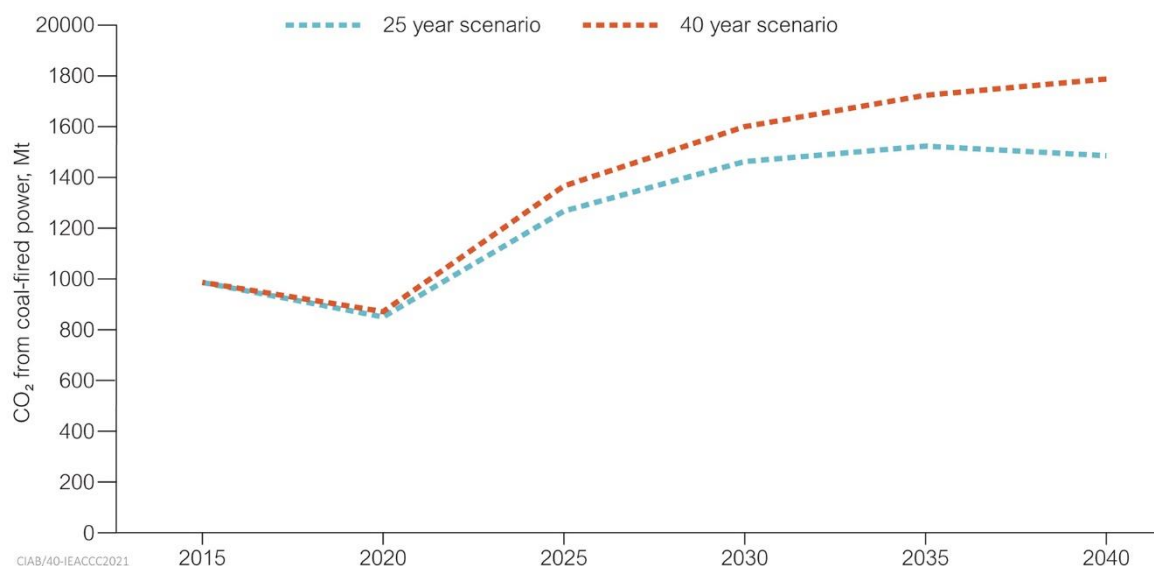


Figure 40 Annual CO₂ emissions from the coal-fired fleet using 25-year and 40-year investment cycles, Mt (IEACCC, 2020)

Compared with a baseline scenario where the fleet continues to operate for 40 years and is not equipped with CCS, the CO₂ avoided can be significant if the life of the plant is revised to 25 years and

CCS is fitted. The simulation calculations suggest that HELE plants could avoid roughly 3550–4300 MtCO₂ between 2021 and 2040, equivalent to an 178-215 MtCO₂/y. The higher end of the range assumes HELE plants are built with CCS fitted to 26 GW of capacity, while the lower end assumes HELE plant is not equipped with CCS. Retiring or replacing units after 40 years, instead of 25 years, leads to a higher emission factor of around 870 kgCO₂/kWh compared with 693–752 kgCO₂/kWh.

6.2 IEA 2020 STATED ENERGY POLICY SCENARIO

At the time of preparing this report, the IEA World Energy Outlook (WEO) edition for 2020 (IEA, 2020d) was published. The IEA WEO 2020 Stated Energy Policy Scenario (IEA 2020 STEPS) is different to the 2019 STEPS in the wake of the disruption caused by the COVID-19 pandemic on the global energy sector. Unlike the IEA 2020 STEPS, the IEA 2019 STEPS is similar to the NITI Aayog outlook for coal-fired power for 2040.

In the 2020 STEPS, COVID-19 is brought under control in 2021 and the global economy returns to pre-crisis levels. The scenario reflects policy intentions and targets set out by governments in 2020 that are backed up by detailed measures. According to the IEA, sharp cost-reductions in solar PV over the last decade have pushed costs below that of gas and coal-fired power in most countries and could meet 80% of the growth of global electricity demand to 2030. However, this is dependent on the strength of electricity grids which could prove to be a weak link in transforming the electricity sector (IEA, 2020d). In the IEA 2020 STEPS, renewables could grow by 9.3%/y during 2019-40, driven mainly by increased solar PV and then wind power. The IEA 2020 STEPS and the IEACCC/NITI Aayog projections illustrate two possible trajectories for coal-fired generation; in the 2020 STEPS, it grows by 0.77%/y during 2019-40, while in the IEACCC/NITI Aayog it increases by 3%/y during the same period.

Criteria	2019	2025	2030	2040	2019-40 change	2019-40 %/y
Coal-fired generation, TWh	1135	1206	1343	1334	199	0.8
Coal-fired capacity, GW	235	269	269	260	25	0.5
CO ₂ emissions from coal power, Mt	1104	1133	1259	1234	130	0.5
Calculated utilisation, %	55.1	51.2	57.0	58.6	3.4	0.3
Calculated emission factor, kgCO ₂ /kWh	973	939	937	925	-47.6	-0.2

The lower path for coal-fired power in the IEA 2020 STEPS compared with NITI Aayog and previous editions of the WEO leads to a limited increase in coal capacity from 235 GW in 2019 to just 260 GW by 2040 (see Table 25). The utilisation of the fleet can be calculated from the forecast TWh output and GW capacity of the fleet; throughout the STEPS forecast period, the annual average utilisation remains broadly at levels seen in 2019, averaging less than 60%. Based on the generation and CO₂ outlook in

the STEPS, the emission factor for the Indian fleet can also be calculated as 973 kgCO₂/kWh (in 2019); by 2040 the fleet shows a modest improvement to reach 925 kgCO₂/kWh (authors' estimates). The IEACCC simulation (Figure 41) exhibits a steeper drop in emission factors from 973 kgCO₂/kWh to 693–752 kgCO₂/kWh due to the aggressive deployment of HELE plant technologies capable of 50% (LHV), which displace the subcritical fleet over the forecast period. Annual CO₂ emissions in the coal power sector increase from 1104 Mt in 2019, to a peak of 1259 Mt in 2035 or thereabouts and decline to 1234 Mt in 2040.

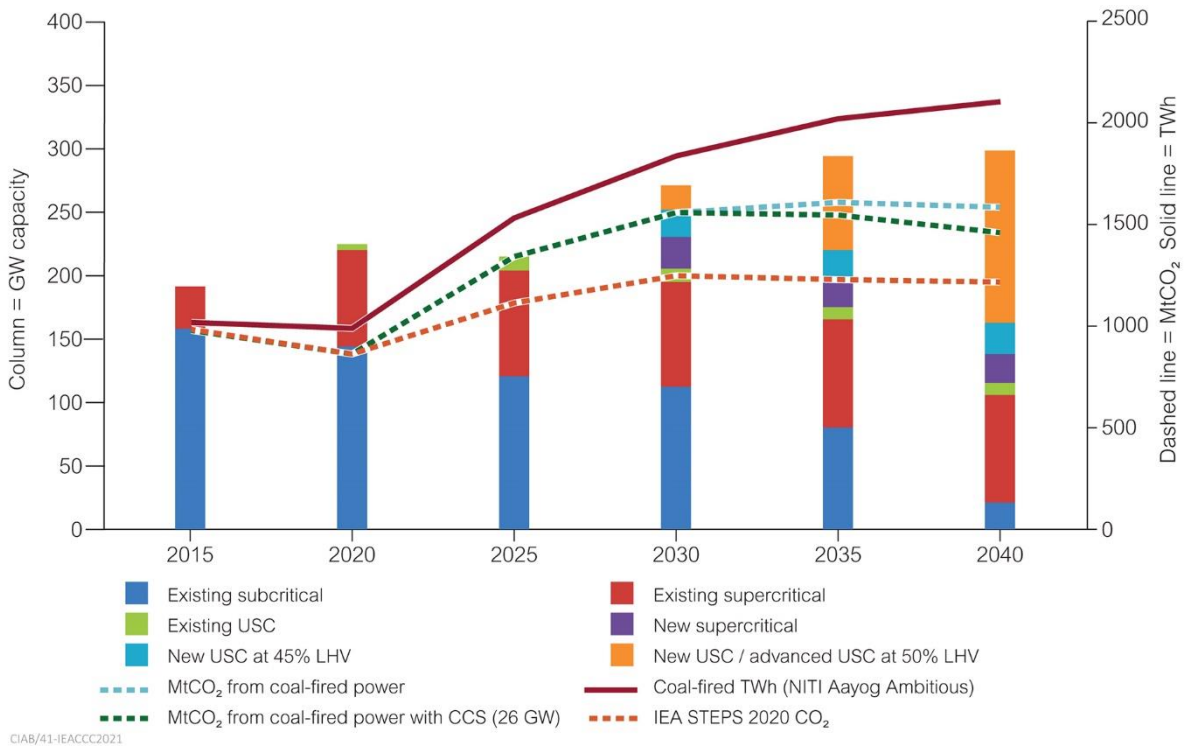


Figure 41 Comparison of the IEACCC HELE outlook based on NITI Aayog Ambitious Scenario with IEA 2020 STEPS CO₂ emissions

6.2.1 IEACCC simulation applied to low capacity scenario

Figure 42 illustrates the IEACCC simulation based on the coal power generation forecast in the IEA 2020 STEPS to 2040. In this simulation the subcritical fleet decreases to 23 GW by 2040 after 25 years of life, and the existing SC and USC plants, including those under construction, remain at 94 GW throughout most of the period. The need for planned additional plant capacity however is lower, with 18 GW of SC and USC plants and 74.2 GW of AUSC or 50% (net) efficiency plants coming online from around 2030 onwards. The addition of HELE plants however leads to a total decrease in CO₂ emissions from 1104 Mt in 2019 to 905.3–1023.6 Mt in 2040 (lower value includes CCS) while emission factors fall to 767 kgCO₂/kWh providing the lowest potential emission pathway for India’s coal fleet.

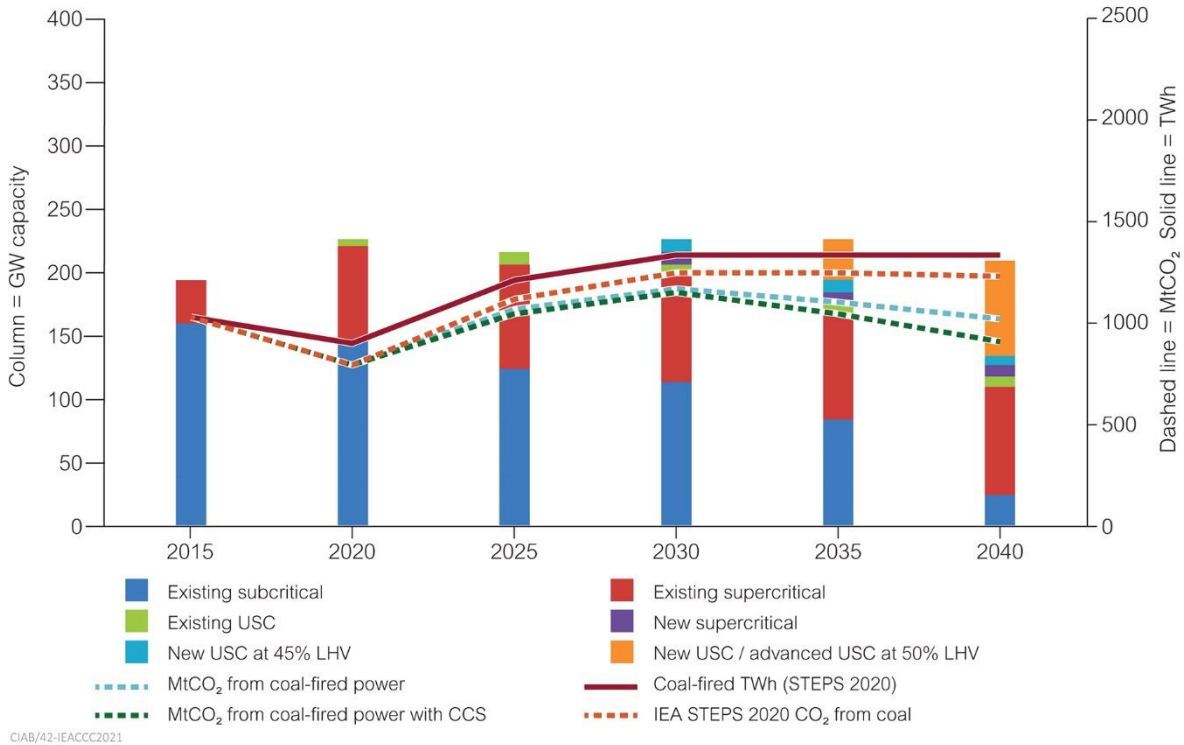


Figure 42 The IEACCC HELE projections applied to the IEA 2020 STEPS outlook for power generation

6.3 SUMMARY

In the NITI Aayog Ambitious Scenario coal-fired generation approximately doubles in the next 20 years to reach almost 2000 TWh in 2040. The additional generation from power plants equipped with CCUS brings the total coal-fired generation to approximately 2120 TWh. This scenario is the basis for the first IEACCC projection.

Since 2007, the rate of coal-fired capacity building outpaced demand for electricity and created a surplus thermal generating capacity which was increased by the effects of COVID-19. Growth in power demand could resume after 2020; despite this there is little need for new coal-fired capacity in coming years due to the spare capacity that exists in the coal fleet. The IEACCC simulation shows retiring around 120 GW of existing subcritical plants after 25 years which could be replaced with cleaner and more efficient coal technology. Rising power demand eventually leads to a need for new net-additions to the coal fleet by around 2026 while existing stations may see a decrease in plant utilisation due to the increase in variable renewable energy.

A rapid shift to HELE plants could avoid at least 3600 MtCO₂ between 2020 and 2040 with a 25-year investment cycle rather than keeping subcritical plants operational for 40 years or more (the baseline scenario). The deployment of 50% (LHV) efficient coal power systems leads to CO₂ emissions plateauing around 2030-35 then falling after 2035. A modest roll out of CCUS can reduce emissions even further, pulling emission factors down to 693 gCO₂/kWh. This is all possible while simultaneously increasing the level of generation from the coal fleet throughout the entire forecast

period. The scenarios depend on the future need for thermal power generation resulting from economic growth and other macroeconomic and development factors discussed in Chapter 2. These various scenarios took the following paths:

1. Baseline: IEACCC simulation assuming a 40-year plant life, NITI Aayog Ambitious outlook for coal generation to 2040
2. IEACCC simulation assuming a 25-year plant life, NITI Aayog Ambitious outlook for coal generation to 2040
3. IEA 2020 STEPS scenario to 2040
4. IEACCC simulation assuming a 25-year plant life, IEA 2020 STEPS outlook for coal generation to 2040

The baseline projection for India's coal fleet already follows a path towards more efficient SC and USC technology and fewer subcritical plants. However, scenarios 2–4 go further to avoid excessive growth in CO₂ emissions from the future Indian coal fleet. Table 26 summarises the results for these various pathways showing the effective routes that could be taken using an accelerated adoption of HELE coal power.

Criteria (2040)	Based on NITI Aayog, 2017a	IEACCC simulation applied to NITI Aayog 2017a		IEA 2020 STEPS	IEACCC Simulation applied to IEA 2020 STEPS	
	40 year life (no CCS)	25 year life (no CCS)	25 year life (with 26 GW CCS)		25 year life (no CCS)	25 year life (with 26 GW CCS)
Coal generation forecast, TWh	2120	2120	2120	1334	1334	1334
SC, USC and 50% efficiency plants, GW	183	277	277	n/a	186	186
Subcritical plants, GW	123	23	33	n/a	23	23
Cumulative CO ₂ emissions 2020-40, Mt	32,802	29,253	28,504	n/a	21,539	20,846
Annual CO ₂ emissions, Mt/y	1849	1592	1467	1234*	1024	905
CO ₂ emission factor, kgCO ₂ /kWh	873	752	693	925*	767	679
* calculated values						

7 CONCLUSIONS AND RECOMMENDATIONS

Coal remains fundamental to meeting India's growing demand

India is a vast country of 1.37 billion people which has undergone rapid economic growth over the last 20 years to become the world's fifth largest economy. This growth has been inextricably linked with a successful drive to increase the availability of electricity, with total power generation increasing by 40% over the last decade. Owing to the country's enormous coal reserves and limited oil and gas, coal-fired power has remained dominant over this period, even slightly increasing its share of total generation to 72% (1135 TWh) in 2019. Despite this remarkable rise, Indians still experience a per capita energy consumption of only around 10% that of high-income countries, and further growth in standards of living and associated energy demand is therefore urgently needed. While the Government of India has ambitious plans to meet much of the expected growth with wind and solar power capacity – up to 400 GW in 2030 – coal will continue to play a fundamental role in providing India with dispatchable power and energy security for the next 20 years and beyond.

The current coal power fleet imposes a significant toll on the environment

However, India's dependence on coal currently comes at a significant environmental cost. Around 1.1 Gt of CO₂ was emitted from India's coal power fleet in 2019, contributing over 10% of global coal power emissions and more than 3% of total CO₂ emissions. If the world is to meet the ambitious climate change mitigation goals set by the Paris Agreement, it is imperative that the forecast expansion in India's coal power generation can be decoupled from increasing greenhouse gas emissions. In the short-term, emissions of particulates and acid gases from India's coal plants are a major contributor to poor air quality which has huge costs in terms of impacts on health and increased mortality of the population. If emissions from thermal power plants were to remain at current levels, some estimates predict that these pollutants could cause up to 1.3 million deaths per year in India by 2050 (Health Effects Institute, 2018). Such far-reaching effects on the health and mortality of the population represent a serious drain on the Indian economy.

Price signals and standards must favour high-efficiency coal power, while older units are encouraged to retire

India has already taken great strides in increasing the efficiency of its coal fleet, as more efficient supercritical (SC) and ultrasupercritical (USC) technologies have now become standard for new plant, while older, less efficient facilities are being phased out earlier. However, this process must be accelerated if the full potential for CO₂ reductions is to be realised. Market incentives for more efficient operation are growing, as India's highly regulated electricity market transitions to more competitive bidding for tariffs and greater use of real-time trading on a national level is encouraged. Despite this trend, newer, more efficient units are often located further from coal mines and struggle to compete with older, pithead plants, given the high cost of transporting coal – it is essential to develop a mechanism to redress this imbalance. While a form of carbon pricing may be employed in future, it is

suggested that efficiency ranking is introduced as a weighting factor in merit order dispatch by discoms, and that minimum efficiency standards are introduced for new and existing units. These standards can be used to further encourage the closure, or significant efficiency upgrading, of older units, and should be combined with an improved regulatory and financial support structure for unit replacement.

New technologies are available to raise the efficiency of new and existing plants

Significant efficiency improvements in the Indian fleet can be achieved with readily available high efficiency, low emissions (HELE) technologies. For the existing fleet, experience has demonstrated that dramatic gains are possible through the implementation of more advanced process control systems and turbine refurbishments in particular. India has also actively sought to develop domestic expertise with state-of-the-art USC designs for new capacity, and has an ambitious programme to develop 700°C advanced USC (AUSC) technology; full-scale demonstration of this important technology should be supported.

As coal power plays a more flexible role, efficiency gains must be preserved

This drive to increase India's coal fleet efficiency is made all the more challenging by the evolving role for coal in the grid, as thermal plants are increasingly required to act as back-up for intermittent renewable generation. A recent study estimates that over 80 GW of the current coal fleet will have to operate flexibly by 2022, including 13 GW expected to conduct daily starts (GTG-RISE, 2020). It is crucial that appropriate market and regulatory signals are developed to ensure that this cycling capacity comprises less efficient units, with SC and USC units allowed to run as baseload where possible.

Up to 3.6 Gt of CO₂ can be avoided by a rapid transition to USC and AUSC technology

This study has quantified the potential for CO₂ reductions in India's coal fleet through the rapid deployment of HELE coal technologies. By assuming an aggressive phase-out policy of units which have reached 25 years and their replacement with USC units – followed by AUSC or other high-efficiency technology from 2030 – it is possible to peak CO₂ emissions from coal power in the early 2030s, while still growing total coal generation to more than 2000 TWh in 2040. This avoids a total of 3.6 GtCO₂ to 2040, relative to an equivalent scenario in which plants are retired after 40 years. Even under a much lower growth outlook for coal (to 1330 TWh in 2040), as projected by the IEA World Energy Outlook 2020, more rapid HELE deployment leads to a 27% lower emissions intensity for the sector in 2040.

The 2015 emission standards can readily be met with existing technologies

India also took a major step towards addressing air pollutants from coal power in 2015, with the introduction of much more stringent emission standards (or norms) for new and existing units. However, progress in meeting these standards through the widespread deployment of flue gas desulphurisation and NO_x control technologies has been slow, with the deadline extended to 2022 and

some NO_x limits relaxed. This study has highlighted that significant NO_x reductions – commensurate with the former 300 mg/m³ target for existing plants – are demonstrably achievable in many Indian coal plants through the adoption of more effective primary control measures alone. Fine-tuning of combustion through better control of coal and air flows in the furnace is of fundamental importance, and can be combined with modifications such as sufficiently separated overfire air. These measures have the added benefit of raising plant efficiency and allowing payback on investment. Although more costly SCR or SNCR will be needed to reach the stricter NO_x limits for newer plants, we emphasise that these technologies can be successfully applied even to the relatively high-ash environments associated with firing Indian coals. Given the high societal costs of poor air quality (estimated at Rs 962,222 crores (US\$139 billion) from PM_{2.5} alone for the period 2015-30), the cost of these modifications should be regarded as an investment rather than an unnecessary burden (Srinivasan and others, 2018).

India has good potential for carbon capture and storage and vital early steps should be taken now

Carbon capture represents the final piece of the puzzle in addressing India's emissions from the coal power sector, but is often framed as too great a challenge for a developing country. Rough early assessments of the India's potential for geological storage of CO₂ have led to premature labelling of the region as unpromising. In reality, there are several potentially suitable sedimentary basins which merit further exploration, as well as potential for enhanced oil recovery and CO₂ storage in deep coal seams and basalt. Better characterisation of this resource should be seen, at the very least, as a valuable means of increasing optionality in India's climate response. The cost of retrofitting state-of-the-art CO₂ capture systems to existing coal plants has fallen significantly following early demonstration, and will continue to do so if further planned developments take place in the USA and China. Progressively deploying CCUS on 26 GW of India's high-efficiency capacity from 2030 to 2040 can avoid a further 750 Mt of CO₂ emissions over the decade. As a means of developing the appropriate revenue streams and policy support required to progress CCUS in India, there is opportunity in linking the technology to the strong political drive behind India's 'Methanol Economy' initiative to expand coal gasification.

Transition to a cleaner coal fleet will place a burden on an already struggling sector

While this study has sought to identify lower cost pathways to reducing emissions where possible, there will undoubtedly be a significant upfront cost associated with many of the steps required. This economic factor is a major hurdle for any developing economy, and one that is greatly exacerbated by the current poor financial health of India's power utility sector. Developing more competitive markets for both energy and coal supply remains an ongoing priority for India which, combined with greater regulatory certainty, should help to stimulate both domestic and international investment. However, coal power plants bear a particularly heavy financial burden, including railway subsidies, grid costs for renewables deployment, coal taxes, and non-competitive coal costs. This position is only expected to become more challenging as large-scale deployment of wind and solar power leads to declining

operating hours. And yet, coal power must remain financially viable if it is to continue supporting India's economic growth while simultaneously investing in cleaner technologies.

The value of dispatchable power must be appropriately compensated and access to finance improved

In order to better compensate the value provided by dispatchable, thermal power plants to the grid, many countries worldwide are developing capacity markets and more attractive compensation for grid services such as ramping, frequency and voltage balancing, and inertia. Such approaches should form the core of India's efforts to improve the viability of HELE coal plants. In addition, direct government support may still be needed to accelerate major initiatives such as the deployment of pollutant control upgrades – this could be derived from a repurposing of the coal cess to fulfil its original function as a clean energy support mechanism (the tax collected Rs 29,700 crores (US\$4.16 billion) in the fiscal year 2017-2018). The Government of India has developed useful financial instruments for driving growth such as Infrastructure Debt Funds, but greater access to international finance is also essential, particularly in the development of CCUS. Supporting efforts to tackle India's coal power emissions must be seen as a priority for international financial institutions such as the World Bank and the Asian Development Bank, and a fundamental obligation under individual nations' commitment to climate lending under the Paris Agreement.

By building on international experience, India can take the lead in cleaner coal technologies

Perhaps equally importantly, international engagement with India must include the flow of expertise, technical and regulatory knowledge, and capacity building, and many existing initiatives have proved highly effective. The rapid modernisation and emissions reductions achieved in China's coal fleet, measures to integrate renewables in Western Europe, and North America's successful deployment of full-scale CCUS are all examples of global experience which can directly inform the pathway taken by India's coal power sector over the coming decades. At the same time, further development of domestic expertise and a manufacturing base for HELE and CCUS technologies can support a valuable global industry in which India is well placed to take the lead.

General recommendations

In addition to the detailed, goal-specific recommendations provided throughout this report, we highlight the following overarching priorities for reducing emissions from India's coal power sector:

- the coal fleet should aim to comprise mostly USC technology or better by 2040, with remaining subcritical units confined to minimal operating hours;
- the 2015 emissions norms can be met using readily available technologies, and any financial support required should be regarded as an investment in the nation's health and economy;
- deployment of CCUS remains a medium-term goal, but groundwork such as storage assessment and regulatory development must be laid now if it is to remain an option;
- the power market should aim to value all aspects of energy provision, including availability, flexibility, and grid reliability and resilience; and

- international support in the form of both investment and expertise should be further encouraged.

There is a real risk that prevailing perceptions of coal as an outmoded energy source, combined with financial challenges, will stifle efforts to transition to cleaner forms of coal power and slow the promising progress made in transforming India's coal fleet. Recognising that coal power will remain fundamental to the country's pursuit of UN Sustainable Development Goals, including affordable and clean energy (SDG7), decent work and economic growth (SDG8), and industry, innovation, and infrastructure (SDG9), maximising the use of HELE coal technologies and CCUS must be seen as key to India's actions on both public health (SDG3) and climate change (SDG13).

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9 APPENDIX

9.1 FACTORS INFLUENCING NO_x FORMATION, EMISSIONS AND CONTROL

This appendix contains the detail on some combustion optimisation measures which influence NO_x emissions and can have an impact on power plant efficiency. It includes mill performance and fuel fineness, coal flow and air flow measurements, and monitoring of oxygen and carbon monoxide.

9.1.1 Mill performance and fuel fineness

Fuel balance and coal fineness are strongly related; according to Storm (2006), most strategies for improving the combustion performance at pulverised coal-fired plants depend on a reduction in coal particle size.

This is because particle fineness has a direct impact on particle heating rates and the transport of both oxygen and oxidation products within the particle (Dong, 2010). Consequently, reduced fineness contributes directly to increased NO_x production and poorer boiler performance resulting in increased carbon-in-ash content, slagging and fouling, secondary combustion at the superheater, elevated CO levels, higher particulate loading on emission control equipment, increased FEGT and increased spray water flows. Optimising the mill operation to ensure its ideal performance and optimal coal fineness is therefore of paramount importance.

A typical requirement for coal fineness is for at least 75% of particles to pass through a 200 mesh screen and for less than 0.1% to remain on a 50 mesh screen (for low NO_x burners) in each of the coal pipes (Storm, 2008). The finer the coal particles, the more the coal and air mixture resembles fluid flow rather than solids in suspension. This means the mixture is more homogenous and consequently distribution is more even between individual burners.

Coal mills are designed for a particular fuel grinding capacity or throughput at a specific Hardgrove Grindability Index (HGI), based on a defined raw feed coal size, moisture content and desired fineness; thus the mill performance changes when different quality coals are ground (Storm Technologies Inc, 2010). Hence, it is important that mills are tuned correctly and deliver fuel of the required fineness.

Mill performance depends on many operating parameters and conditions and is limited by various factors including the need to maintain flame stability, milling capacity, pulverised coal transport, duct erosion, tempering and fuel drying. However, there are several ways in which coal fineness can be optimised. Regardless of coal and mill type, these include control and/or improvement of the following: raw coal size and feed rate, mill parts such as classifiers, primary air flow (volume and velocity) and mill inlet and outlet temperatures.

Accurate, real-time measurement of coal fineness is important. Unfortunately, at most power plants, particle fineness is checked only occasionally – once or twice a year. Furthermore, the dominant measurement method is manual isokinetic sampling. This is labour intensive, has a large margin of error and does not give simultaneous or real-time results from all coal pipes. This means it cannot be used for the accurate, real-time optimisation of particle fineness and mill performance. Fortunately, new online methods have emerged in recent years, which are more accurate and provide reliable, real-time results. The new systems are based on a variety of operational techniques, such as acoustic emissions, electrostatics, laser and white light, most of which allow the simultaneous measurement of particle fineness as well as coal flow (velocity and concentration). Several manufacturers offer these solutions including Promecon, GreenBank and EUtech Scientific Engineering.

The use of new online measurement systems means rapid detection of issues and thus enables faster implementation of measures to improve coal fineness. These include: ensuring raw coal of the correct/optimal size is supplied to the mill; keeping the mill grinding elements in good condition; applying the correct grinding pressure; setting the correct throat clearance and air flow; maintaining the classifier and sustaining suitable mill inlet and outlet temperature.

Regardless of the chosen technology, it is important to sample simultaneously all the coal lines of all the mills to ensure the desired fuel fineness at all the burners. Choosing the optimal sampling location and ensuring an appropriate calibration of the equipment is essential to obtain a representative sample.

The high ash content, low GCV and high volume of coal through the fuel pipes, and erosion caused by ash means that the O&M for such instruments and their reliability is a concern. EPRI is currently evaluating this subject for India (Storm, 2020). For more details on the best operation of an Indian plant, see ‘Best practices manual for Indian supercritical plants’, created by USAID in collaboration with the India Ministry of Power, NTPC and other stakeholders (USAID, 2014). For more detailed information including case studies see the IEACCC report by Wiatros-Motyka (2016).

9.1.2 Coal flow measurements

The absence of fuel flow optimisation creates many problems. For example, high coal flow to burners can lead to increased slagging and emissions of carbon monoxide. Too little coal flow to burners can increase emissions of NO_x. If pulverised fuel is delivered to the burner at too high a velocity this can increase erosion of the system, cause high carbon-in-ash levels and even detachment of the flame within the boiler. Delivery at too low a velocity can cause fall out of particulates and create pipe blockages which can lead to dangerous fires and explosions (Wiatros-Motyka, 2016). Hence three aspects of fuel flow need to be addressed (Conrads, 2020):

- coal mass flow;
- coal velocity; and
- coal deposits in horizontal pipe sections.

Conventionally, coal flow is monitored by the volumetric or gravimetric (to a much lesser extent) feed rate of coal to the mills and is directly dependent on the boiler firing rate and the current load demand of the plant (Lockwood, 2015). Power plants have multiple mills and fuel is transported to the individual burners via geometrically different pipes; fuel will take the easiest route (with the lowest pressure drop) to the burner (Greenbank, nd). Unless accurate measurement of fuel flow and fuel flow control devices are in place, uneven fuel distribution, roping and pipe blockages can and will occur. In many power plants the coal mass flow distribution between different burners shows an imbalance of up to 25% (Conrads, 2020). This means it is necessary to control and optimise the fuel distribution from each mill to its corresponding burners.

Some of the new systems for coal flow measurement can also measure coal fineness. They are much more accurate than manual sampling, give real time feedback and are not labour intensive. Various factors affect their performance, so the following should be considered before choosing a coal flow measurement system: whether the equipment can be incorporated into the existing coal pipe geometry and if not what changes are required; the operational mode of the equipment (whether stationary or mobile); the need for, ease of and time required for calibration; scale down and consequent shutting down of the plant; the sensitivity of the system to high temperatures and flue gas conditions such as stratification, moisture and different velocities; the impact of pipe geometry; if the system is user friendly; proven rate of success; the return on investment (ROI), and the need for O&M upkeep for the system.

Accurate fuel flow measurements in all coal pipes allows the effective use of flow distribution devices. Recently, there have been considerable developments in such systems. The most advanced ones are effective in delivering even coal flow distribution, have low pressure drop and a minimal effect on the primary air distribution, can be installed in different pipes/configurations and with different mills, and in most cases can be controlled automatically.

Some new Indian units, such as the Darlipalli and Meja plants have incorporated fuel flow control valves as well as microwave-based systems for measuring coal mass flow. However, to date these new systems have not been used to optimise combustion as the plants have not yet been fully commissioned. In Europe, several power plants use mass flow measurement systems for coal or biomass including Drax in the UK, Maasvlakte in the Netherlands, E.ON PS Wilhelmshaven and Riverstone PS Wilhelmshaven in Germany and Rybnik in Poland.

For more detailed information including case studies which highlight the cost-benefits to power plants after implementation of advanced system for coal flow controls see the IEACCC report by Wiatros-Motyka (2016).

9.1.3 Air flow measurements

All air flows in a power plant must be measured and controlled in order to achieve optimum combustion at the boiler and avoid problems such as high FEGT, secondary combustion, overheating in the back-pass as well as slagging and increased corrosion rates due to reducing atmospheres associated with poor fuel distribution, fuel rich zones and other factors.

The most commonly used, traditional procedure for air flow measurement is based on differential pressure (dP). Differential pressure measurement of both primary air and mill air is conducted to avoid some typical coal pulveriser problems, such as insufficient coal drying or excessive duct wear. Figure 43 is an example of dP of the mill versus dP of primary air. It shows that for this power plant, the ratio of mill dP (vertical axis shown on the graph) to primary air dP (shown on horizontal axis) must be within a specific range to avoid operational problems.

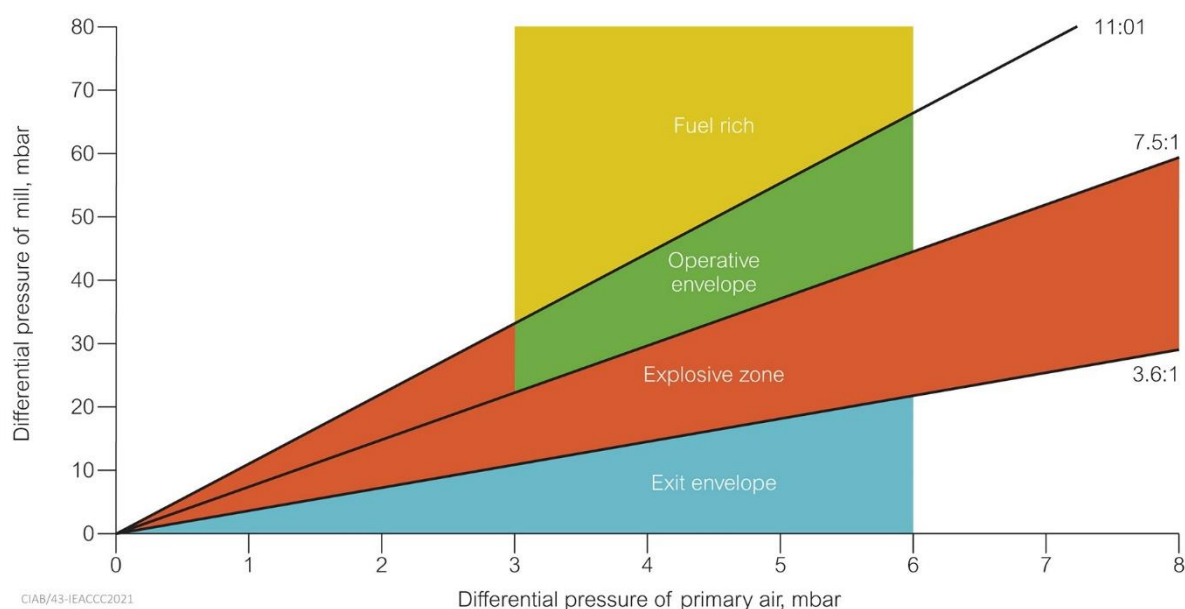


Figure 43 Example of operating envelope, relating mill dP to primary air dP

This type of measurement can be performed over different piping/profile elements and can be divided into: venturi, orifice, perforated plate or profile (carried out with the use of annubar, varibar or pitot tubes) measurements.

However, air streams in coal power plants are turbulent, stratified, hot, moist and particle-laden, which complicates air flow measurement. Additionally, air ducts to and from different mills have various geometries and lengths which impact air measurement devices. This is particularly true of the most traditional devices which generally need to be installed on a certain length of straight and obstacle free pipe. Many also require field calibration and most of the portable calibration devices require a laminar flow that does not exist in most combustion air flow ducts. Moreover, many devices provide air flow measurements based on an assumed cross-sectional area of the given air duct, but as air ducts expand and contract, their cross-section changes and the readings give errors. Hence frequent maintenance is

essential to ensure accuracy but is often not carried out as it is a time consuming and laborious process. Consequently, such measurements can have a considerable margin of error, of up to 15%. This means that the burner stoichiometry can vary between 0.7 and 0.9 when the design value is actually 0.8. This has a direct impact on NO_x formation as well as the CO and unburnt carbon losses of the boiler (Conrads, 2020).

This problem exists across the burner rows as well as across the burner elevations. Thus, it is a three-dimensional problem in a combustion space of approximately 20 m x 20 m x 70 m. This means there is a high potential for NO_x formation and pockets of CO if not leveled out correctly at the OFA level. In such cases, the boiler will underperform (Conrads, 2020).

More advanced technologies for combustion air flow measurement attempt to deal with the difficulties of measuring turbulent and stratified, particle-laden air flows. Such systems include advanced pitot tubes, electrostatic based systems, thermal mass flow meters, and virtual and optical sensors. These systems are more accurate than the old ones and are designed to avoid clogging, corrosion and breaking. Manufacturers such as Promecon, EUtech Scientific Engineering, Kurtz Instruments Inc and others offer such systems. But all technologies have limitations and care should be taken to comply with product specifications for restrictions (temperature, flow, particulates, moisture, straight run and more).

All systems must be validated and/or calibrated. Comparative analysis of theoretical combustion air flow with measured air flow and excess oxygen management is a good approach to monitor degradation in airflow measurement over time. This is also considering that the air flow measurement controls are trimmed by excess oxygen measurement, which can be negatively impacted by air in-leakage upstream of the oxygen measurement probes (Storm, 2020). For more detailed information, including case studies, see the IEACCC report by Wiatros-Motyka (2016).

9.1.4 Monitoring of oxygen and carbon monoxide

Accurate monitoring of oxygen concentration in the furnace is critical for total combustion control. This is because the oxygen measurement is used to determine excess air and hence allows control of air and fuel flow to the individual burners. However, oxygen measurement can be affected by air ingress to the boiler. Hence, oxygen measurement should be accompanied by CO monitoring, which is considered the most sensitive and accurate indicator of incomplete combustion (Lockwood, 2015). The flue gas in the convective pass is relatively 'stratified' (as individual columns emitted by each burner) which means that localised regions of high CO and oxygen can be present even in the economiser exit. So, it is important to choose the most suitable system and to have the sensors placed at multi-point representative locations, as a grid, to enable accurate readings and consequent flow optimisation.

New advanced systems can measure both oxygen and CO as well as temperature and other flue gas components. CO sensors detect zones of poor combustion, while oxygen sensors detect zones with excess oxygen. This allows burner adjustments to be made and excess air redistribution from high excess oxygen zones to regions of poor combustion. There are various combustion tuning systems which use advanced sensors. They have automated controls to keep sensors clean and calibrated. When integrated into a distributed control system (DCS) they allow combustion tuning and can reduce NO_x emissions by 10–20%. Other benefits include improved efficiency, increased throughput capacity on fan-limited units, reduced average furnace exit gas temperature and reduced carbon in ash (CIA) (Power Magazine, 2009).

An example of a technology which measures both CO and oxygen with a grid of extractive probes is the Delta Measurement and Combustion Controls (DMCCO) system (Ferri and Volpicelli, 2015). The DMCCO system uses non-dispersive infrared (NDIR) and zirconia sensors for CO and oxygen measurements respectively. It also measures gas temperature and nitric oxide levels. Additionally, the DMCCO is resistant to ash particles and can separate moisture and water vapour from the sampled gas. Its effectiveness, in combination with air and coal monitoring systems, is described in Wiatros-Motyka (2016). Other technologies which are capable of simultaneous measurement of CO, oxygen and other flue gas components (including NO, NO₂, SO₂) are based on tunable diode laser absorption spectroscopy (TDLAS). Commercial examples of such systems include ZoloBOSS from Zolo Technologies and TDLS200 TruePeak Analyser from Yokogawa (Yokogawa, 2010; Zolo Technologies, 2011). These systems position a source and a detector on opposing walls and create a laser grid which provides an average measurement of gas concentration as well as temperature over the entire measurement path. For more detailed information see the IEACCC report by Lockwood (2015).