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BEST PRACTICES AND TECHNOLOGIES FOR COAL-FIRED POWER PLANTS IN INDIA

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PREFACE

This report has been produced by the International Centre for Sustainable Carbon (ICSC) and 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.

The International Centre for Sustainable Carbon was established in 1975 and has contracting parties and sponsors from Australia, China, Italy, Japan, and South Africa.

The overall objective of the International Centre for Sustainable Carbon is to continue to provide our members, the International Energy Agency (IEA) Working Party on Fossil Energy and other interested parties with definitive and policy relevant independent information on how various carbon-based energy sources can continue to be part of a sustainable energy mix worldwide. The energy sources include, but are not limited to coal, biomass, and organic waste materials. Our work is aligned with the UN Sustainable Development Goals (SDGs), which includes the need to address the climate targets as set out by the United Nations Framework Convention on Climate Change (UNFCCC). We consider all aspects of solid carbon production, transport, processing, and utilisation, within the rationale for balancing security of supply, affordability, and environmental issues. These include efficiency improvements, lowering greenhouse and non-greenhouse gas emissions, reducing water stress, financial resourcing, market issues, technology development and deployment, ensuring poverty alleviation through universal access to electricity, sustainability, and social licence to operate. Our operating framework is designed to identify and publicise the best practice in every aspect of the carbon production and utilisation chain, so helping to significantly reduce any unwanted impacts on health, the environment and climate, to ensure the well-being of societies worldwide.

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BACKGROUND

This report is one in the series of reports intended to provide capacity building in the thermal power sector in India under a grant from the US Department of State (USDOS). This report complements previous reports from the project – *Status of continuous emission monitoring systems at coal-fired power plants in India* (December 2021), *Achieving 100% ash utilisation at coal-fired power plants in India* (May 2023) and *Best practices in CEM (continous emission monitoring)* (June 2023).

The purpose of this report is to provide capacity building to coal utility stakeholders for optimal plant operation and pollution control. Thus, the report offers information on the established best technologies and practices in plant operation and pollution control in coal-based thermal power plants in India.

This technical report represents the results of a piece of work that forms part of a significant project undertaken by the International Centre for Sustainable Carbon (ICSC) on behalf of the USDOS, Agreement Number: SLMAQM19CA238: 'Capacity building in Southeast Asia to reduce mercury and other pollutant emissions from the coal combustion sector'. The project comprises two major areas of work to reduce emissions from the coal-fired power sector: one in Indonesia focusing on mercury emissions; and the second in India which addresses additional pollutants – sulphur dioxide (SO_2) nitrogen oxides (NOx), and particulate matter (PM) as well as mercury. The project in India focused on knowledge sharing and capacity building, in 3 pillars of work:

- Pillar 1 – emissions monitoring;
- Pillar 2 – emissions reduction, and ash management;
- Pillar 3 – flexibility of plant operation.

More details on this USDOS project can be found on the ICSC website: www.sustainable-carbon.org.

ABSTRACT

Pollutant emissions from coal combustion in utility plants will be reduced when the plant is operated efficiently and effectively. The operation of a coal plant requires complex engineering. However, there are basic guidelines which can be followed which identify where and how best practices can be applied. This report provides high-level stakeholders with a clear overview of the technologies and techniques which should be considered at every coal-fired plant to ensure that it is operating at peak performance.

ACRONYMS AND ABBREVIATIONS

ACI	activated carbon injection
AWRS	ash water recovery system
BAT	best available technology
BEP	best environmental practice
Capex	capital expenditure
CCUS	carbon capture, utilisation, and storage
CEA	Central Electricity Authority, India
CEM	continuous emission monitor(s)
CERC	Central Electricity Regulatory Commission, India
CFBC	circulating fluidised bed combustion
CIA	carbon in ash
CFB	circulating fluidised bed
CFD	computational fluid dynamics
CHP	combined heat and power
COHPAC	compact hybrid particulate collector
CPA	Critically Polluted Area
CPCB	Central Pollution Control Board, India
CSE	Centre for Science and Environment, India
DSI	dry sorbent injection
EPRI	Electric Power Research Institute, USA
ESP	electrostatic precipitator
EU	European Union
FD	forced draught
FEGT	furnace exit gas temperature
FF	fabric filters (baghouse)
FGD	flue gas desulphurisation
GCV	gross calorific value
GHG	greenhouse gas
HELE	high efficiency low emission
ICSC	International Centre for Sustainable Carbon
ID	induced draught
IEA	International Energy Agency
INR	Indian rupee
ITPCL	IL&FS Tamil Nadu Power Company Ltd, India
LNB	low NOx burner
LHV	lower heating value
LOI	loss on ignition
MACT	maximum achievable control technology, USA
MEEP	moving electrode electrostatic precipitator
MOEFCC	Ministry of Environment, Forest, and Climate Change, India

MOP	Ministry of Power, India
MOC	Ministry of Coal, India
NCR	National Capital Region, India
NID	novel integrated desulphurisation
NPC	National Productivity Council, India
NTPC	major state-owned utility in India (formerly known as National Thermal Power Corporation)
OFA	overfire air
Opex	operational expenditure
OTC	once-through cooling
O&M	operation and maintenance
PAC	powdered activated carbon
PLF	plant load factor
PM	particulate matter
ppm	parts per million
R&D	research and development
SC	supercritical
SCR	selective catalytic reduction
SG	scheduled generation
SMR	steam methane reforming
SNCR	selective non-catalytic reduction
SOFA	separated overfire air
SPCB	State Pollution Control Board
TDS	total dissolved solids
TPP	thermal power plants
UN	United Nations
UNEP	United Nations Environment Programme
USC	ultrasupercritical
USDOE	United States Department of Energy
USDOS	United States Department of State
USEPA	United States Environmental Protection Agency
VFD	variable frequency drive
VRE	variable renewable energy
ZLD	zero liquid discharge

Note: all monetary values are in United States dollars ($) unless otherwise stated.

UNITS

Btu	British thermal unit
cm	centimetre
g	gramme
GJ	gigajoule
g/s	gramme per second
Gt	gigatonne
GW	gigawatt
h	hour
ha	hectare
kcal	kilocalories
kg	kilogramme
km	kilometre
kWh	kilowatt-hour
m	metres
m^3	presumed to be normal m^3 (Nm^3), at standard temperature and pressure
mg	milligrammes
mg/m^3	milligrammes per cubic metre
MJ/kg	megajoule per kilogramme
MLD	million litres per day
MPa	megapascal
Mt	million tonnes
Mt/y	million tonnes per year
MW	megawatt
MWth	megawatt (thermal)
t	tonnes
t/y	tonnes per year
TWh	terawatt-hour
µm	micrometre (10^{-6} metre)
y	year

CHEMICALS

Hg	mercury
NH_3	ammonia
Ni	nickel
NOx	oxides of nitrogen
SO_2	sulphur dioxide
SO_3	sulphur trioxide

CONTENTS

PREFACE 4

BACKGROUND 5

ABSTRACT 6

ACRONYMS AND ABBREVIATIONS 7

CONTENTS 10

LIST OF FIGURES 12

LIST OF TABLES 13

1 INTRODUCTION 14

1.1 The Indian thermal power sector 14

1.2 Indian emission standards for coal plants 15

1.3 Comments 17

2 COAL-FIRED POWER PLANTS – TECHNOLOGIES AND PROCESSES 19

2.1 Subcritical coal plant 19

2.2 Ultrasupercritical coal plant 20

2.3 Factors affecting plant performance 22

2.3.1 Plant load factor 22

2.3.2 Heat rate and efficiency 24

2.4 Flexibility of power plant operation 25

2.5 CO_2 emission reduction practices 30

2.6 Case studies 33

2.6.1 Case study 1: efficiency improvement at RDK Power plant, Germany 33

2.6.2 Case study 2: boiler efficiency improvement at Suralaya 33

2.6.3 Case study 3: reheat efficiency improvement at Nordjylland 34

2.7 Comments 34

3 COAL HANDLING, PREPARATION AND PROCESSING 36

3.1 Pit-head plants 36

3.2 Coal transport and handling 37

3.2.1 Transport 37

3.2.2 Coal unloading 38

3.2.3 Coal preparation 38

3.2.4 Coal storage 38

3.3 Coal beneficiation 39

3.3.1 Coal washing 39

3.3.2 Coal blending 40

3.4 Comments 44

4 BEST PRACTICE IN WATER CONSUMPTION AT COAL-FIRED UTILITIES 45

4.1 Alternative sources of water 46

4.2 Examples of advanced water treatment systems 47

4.3 Comments 48

5 EMISSIONS REDUCTION 49
5.1 Particulate control 50
5.1.1 Electrostatic precipitators 50
5.1.2 Fabric filters 52
5.1.3 Advanced PM control systems 55
5.2 SO_2 emission control 56
5.2.1 Flue gas desulphurisation 56
5.3 NOx emission control 65
5.3.1 Primary NOx control measures 67
5.3.2 Secondary NOx control measures 72
5.4 Mercury control 76
5.5 Carbon capture, utilisation and storage 79
5.6 Comments 84
6 CONCLUSIONS 85
7 REFERENCES 87

LIST OF FIGURES

Figure 1 Generation capacity in India by fuel type 15
Figure 2 Process flow diagram of a typical subcritical coal-fired power plant 20
Figure 3 High efficiency coal-fired power plant technology 22
Figure 4 Deviation in efficiency with various load conditions 23
Figure 5 Basic operational flexibility in coal-fired power plants 26
Figure 6 Flexibility strategy versus cost 28
Figure 7 High-level flexibility assessment tool application 29
Figure 8 Tube or pipe conveyor and enclosed conveyor 37
Figure 9 Covered coal storage with stacker reclaimer 39
Figure 10 Schematics of water use in a typical 1000 MW coal-fired power plant 45
Figure 11 Diagram of a typical ESP 50
Figure 12 Schematic of ESP process of duct collection 51
Figure 13 Schematic of a fabric filter 53
Figure 14 Different FF designs and configurations 54
Figure 15 Schematics of limestone-based wet FGD 57
Figure 16 Schematics of ammonia-based wet FGD 57
Figure 17 Schematics of seawater FGD 58
Figure 18 Schematics of a spray dryer absorber 59
Figure 19 Schematics of a CFB dry scrubber FGD system 60
Figure 20 Schematics of NID 61
Figure 21 Schematics of DSI 62
Figure 22 Schematics of ReACT 64
Figure 23 Schematics of a typical coal-fired plant with various DeNOx installations 66
Figure 24 NOx reduction levels with various control technologies in the EU 66
Figure 25 Combustion parameters versus air-to-fuel ratio 68
Figure 26 Schematics of an LNB 69
Figure 27 A typical OFA system 71
Figure 28 Schematic of a typical SCR system 72
Figure 29 Different SCR positions in a typical coal-fired plant 73
Figure 30 Schematic of SNCR 74
Figure 31 Schematics of the SNOX™ process 76
Figure 32 Schematics of ACI/sorbent injection for mercury control 78
Figure 33 Comparative analysis of various CO_2 capture technologies appropriate in India 81
Figure 34 Major large-scale commercial carbon capture projects worldwide 83

LIST OF TABLES

Table 1	Emission norms for existing coal thermal power plants: India and global	16
Table 2	Emission norms for new coal thermal power plants: India and global	17
Table 3	comparison of Subcritical, supercritical and ultrasupercritical coal combustion	21
Table 4	Heat rate benchmark	24
Table 5	Plant efficiency benchmark	25
Table 6	Flexibility paramaters	27
Table 7	Best practices for operational improvement in a coal-fired power plant	32
Table 8	Current emissions standards for coal-fired power plants in India	49
Table 9	Mercury removal (%) co-benefits with various air pollution control devices	77
Table 10	Comparative analysis of various CO_2 capture technologies	80
Table 11	Various utilisation pathways for CO_2 captured by CCUS	82

1 INTRODUCTION

Globally, power is generated from conventional sources (thermal, nuclear, and hydro) and renewables (such as wind, solar and biomass). In India, the majority of electricity is produced from coal-based thermal power plants (TPP) which contribute around 70% of the total power generation (PIB, 2023b). India's total power generation in 2020-21 was 1491.9 billion kWh, according to Central Electricity Authority data (CEA, 2024).

The Indian thermal power sector is the major consumer of coal and is recognised as a significant source of air pollution. Modern coal-fired power plants pollute less than the original subcritical plant designs per megawatt (MW) generated, due to higher boiler efficiencies and new technologies that filter the flue gases. However, pollutants are still being emitted at concentrations which are several times higher than emissions from natural gas-based power plants and lead to regional pollution and air quality problems. Emissions from coal include pollutants such as sulphur dioxide (SO_2), nitrogen oxides (NOx), particulate matter (PM) and mercury (Hg). Emission limits and regulations have been evolving, regionally, since the 1980s. In India, stringent environmental norms were introduced by the Ministry of Environment, Forestry, and Climate Change (MOEFCC) in 2015, but implementation is still in progress.

1.1 THE INDIAN THERMAL POWER SECTOR

India's total installed power generation capacity, including fossil and non-fossil fuels, is 411 GW (Ministry of Power, 2023). This is the third largest national capacity globally and 57% comes from fossil fuels. Half of the total Indian capacity is owned by the private sector and 25% each by the central government and state.

Coal- and lignite-based power generation capacity is nearly 52% of the total, whereas renewable energy contributes 40%, and gas and nuclear together provide 8%, as shown in Figure 1. The contribution of renewables is growing significantly whereas the percentage of coal is gradually declining (Ministry of Power, 2023).

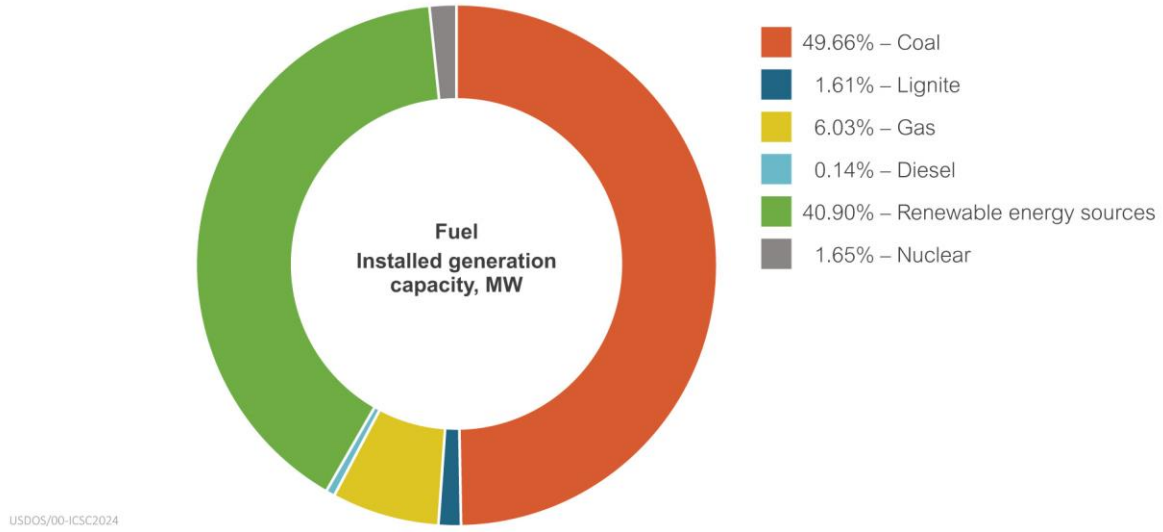

Figure 1 Generation capacity in India by fuel type (Ministry of Power, 2023)

Overall power generation in India was more than 1490 TWh in 2021-22, indicating a recovery rate of 7% growth over generation reported during the Covid-19 pandemic of 2020-21. Over 5% growth was maintained over the few years before Covid-19 (Ministry of Power, 2023). Coal-based generation during this period was estimated at 75% of the total with a low plant load factor (PLF) of less than 60% (CEA, 2024).

As India continues its rapid economic development, an increase in demand for electricity is inevitable. It is likely that, in the near term at least, some of this demand will be satisfied by new or improved coal-fired power plants and also that a significant proportion of the existing fleet will remain in operation. Coal-fired power plants will therefore be an integral part of the generation capacity in India for some time, even as the country moves towards higher capacity and output of renewable energy (Sloss and others, 2023a).

1.2 INDIAN EMISSION STANDARDS FOR COAL PLANTS

The power sector is one of the most polluting in India, contributing 60% of the total PM, 45% of the total SO_2, 30% of the total NOx, and more than 80% of the total mercury emissions from all industrial sectors in the country in 2020 (CSE, 2020a). To address the air pollution, the Ministry of Environment, Forest, and Climate Change (MOEF&CC) set stringent emissions limits in December 2015 for PM, SO_2, NOx and mercury and also restricted the water usage of coal-based thermal power plants. These emission standards, or 'norms', were to be binding by 2017 initially. However, relaxations and derogations have resulted in delays in implementation. Tables 1 and 2 below compare emission norms for existing and upcoming power plants in India with other countries.

TABLE 1 EMISSION NORMS FOR EXISTING COAL THERMAL POWER PLANTS: INDIA AND GLOBAL (CREA, 2024)				
Jurisdiction	SO_2	NOx	PM	Mercury
	mg/m^3	mg/m^3	mg/m^3	$\mu g/m^3$
EU: from 2023 (hard coal)	130	150	8	4
EU: from 2023, lignite	130	175	8	7
China: from 2020	35	50	10	30
EU: from 2015	200	200	20	–
USA	640	640	23	1.6
China: all plants	200	100	30	30
Japan	200	376	46	–
India: installed before December 2003	600 (<500 MW) 200 (≥500 MW)	600	100	30 (≥500 MW)
India: units installed during 2004-2016	600 (<500 MW) 200 (≥500 MW)	450 (revised)	50	30
Turkey	400	200	50	–
Chile	400	500	50	–
South Africa	680	1020	68	–
Indonesia	589	589	107	–
Australia	–	856	109	–
Philippines	1607	1607	214	–
Vietnam	500	1000	400	–
Note: PM, SO_2, NOx and mercury units in are in mg/m^3 which is assumed to be normal cubic metre, Nm^3				

Emission standards for newer (operational after 2003) coal-based thermal power plants in India are more stringent than many other countries. Even tighter standards are being set for new plants, as shown in Table 2.

TABLE 2 EMISSION NORMS FOR NEW COAL THERMAL POWER PLANTS: INDIA AND GLOBAL (CREA, 2024)				
Jurisdiction	SO_2	NOx	PM	Mercury
	mg/m^3	mg/m^3	mg/m^3	$\mu g/m^3$
China	35	50	10	30
USA – MATS	60	99	13	0.5
EU, hard coal	75	85	5	2
EU, lignite	75	85	5	4
India (after 1 January 2017)	100	100	30	30
Turkey	150	150	10	30
South Korea	229	164	18	30
Vietnam	350	455	140	30
Philippines	594	1071	161	30
South Africa	680	1020	68	30
Indonesia	804	804	107	30
Australia	–	856	109	30

MATS – Mercury and Air Toxics Standard

Note: PM, SO_2, NOx and mercury units in are in mg/m^3 which is assumed to be normal cubic metre, Nm^3

The deadline for compliance for Indian thermal power plants, at present, varies from December 2022 to December 2025 depending on the plant's proximity to a city with a population of one million or more, to non-attainment areas, and to Critically Polluted Areas (CPA). Category A plants are required to comply first, by the end of December 2022. They are located within a 10 km radius of the National Capital Region (NCR) or cities with a population of more than 10 lakh (1 million). The deadline is one year later (end of December 2023) for Category B plants, which are those located within a 10 km radius of CPA or from non-attainment cities. The remaining non-retiring plants (from Category C) are given a two-year longer compliance period (until the end of December 2024). Retiring plants from Category B and C must comply by the end of December 2025. Plants which remain out of compliance with the norms beyond the deadline face category-wide fines ranging from 0.075–0.20 INR/kWh (0.0090–0.0024 $/kWh) (Sloss and others, 2023a) .

1.3 COMMENTS

India relies heavily on coal to provide power for its growing population and industrial development. However, the coal sector is also currently one of the major sources of the major pollutants – PM, SO_2, NOx and mercury. New regulations from the Indian government mean that most Indian plants must take action to reduce their emissions or will face financial penalties. Many Indian plants therefore have to consider the most cost-effective options to reduce emissions. This report summarises the relevant

factors of coal plant operation which affect the performance and emissions from coal-fired utilities to highlight all areas where improvements can be made.

This document is not intended to be a detailed manual for coal plant operation, but rather a summary of the major factors which affect the performance of a coal plant and which, once optimised on a plant-specific basis, can be part of an emission reduction strategy at all levels from individual unit to national coal fleet.

2 COAL-FIRED POWER PLANTS – TECHNOLOGIES AND PROCESSES

Pulverised coal (PC) combustion is the most widely used technology in coal-fired power plants globally. Coal-fired power generation faces many challenges including demands to reduce greenhouse gas (GHG) and non-GHG emissions, to minimise water use, while delivering dispatchable and flexible operation. Since coal continues to be a key energy choice in many growing economies, there is a significant international drive towards adoption of high efficiency low emissions (HELE) coal power systems. Developments have primarily involved increasing plant thermal efficiencies by raising the steam pressure and temperature. Thermal power plant technology and operational processes have a direct impact on the efficiency and environmental performance of a plant and ultimately on the emission rate of all pollutants. The best applicable technologies (BAT) and best environmental practices (BEP) in operation are critical for optimal environmental performance.

There are significant ongoing innovative developments to improve overall plant performance and operational flexibility internationally. These improvements increase efficiency (reducing fuel use and cost and reducing emissions per unit generated) and also to help maintain grid capacity as most countries prioritise renewable energy contribution to the grid. Transformational developments underway offer improved prospects for maintaining robust coal-fired units while ensuring further reduction of all emissions.

The following sections review the basic types of coal-fired utilities in operation, highlighting how their performance can be optimised to lower emissions. The focus is on the boiler and related technologies – downstream flue gas technologies are discussed in the following chapters.

2.1 SUBCRITICAL COAL PLANT

A typical coal-fired power plant (Figure 2) uses coal as a primary raw material which is processed prior to combustion in the boiler.

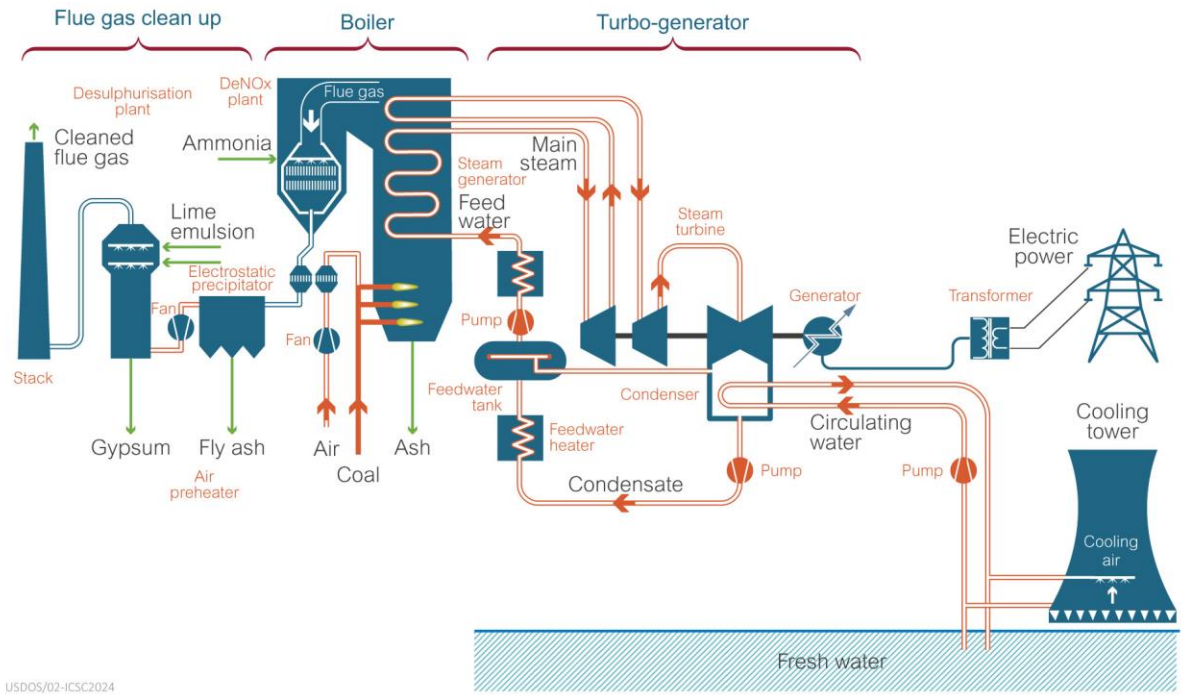

Figure 2 Process flow diagram of a typical subcritical coal-fired power plant (Mahmud and others, 2013)

Using the heat from the boiler, water is converted into steam and then super-heated. The super-heated steam is introduced to a series of turbines connected to a generator to produce electricity. The exhaust steam from the turbine is condensed and pumped back into the boiler to repeat the cycle. Waste steam is released from the cooling towers. The waste gas from the coal combustion is passed through air pollution control devices before being released into the atmosphere. Solid and hazardous wastes such as fly ash, bottom, gypsum, and catalysts are reused and, or disposed of in a controlled manner. A separate report *Accelerating emission control at coal-fired power plants in India* (Sloss and others, 2023a) covers air pollution control aspects whereas *Achieving 100% ash utilisation at coal-fired power plants in India* (Sloss and others, 2023b) covers the solid waste management aspect of coal-fired power plant. This complementary report is a high-level summary of the best technologies and practices of coal-fired power plants in India.

2.2 ULTRASUPERCRITICAL COAL PLANT

Combustion techniques and technologies have improved since the development of subcritical coal plants and more advanced systems – supercritical (SC) and now ultrasupercritical (USC) technologies are state-of-the-art. Table 3 below outlines the major differences between these technologies.

TABLE 3 COMPARISON OF SUBCRITICAL, SUPERCRITICAL AND ULTRASUPERCRITICAL COAL COMBUSTION (NALBANDIAN-SUGDEN 2008)

Parameters	Subcritical	Supercritical	Ultrasupercritical
Main steam pressure, MPa	<22.1	22.1–25	>25
Main steam temperature, °C	<565	540–580	>580
Reheat steam temperature, °C	<565	540–580	>580
Average efficiency, (LHV, net), %	36	45	>45
CO_2 intensity, g/kWh	766–789	722	<722
Power generation cost, US¢/kW	4.0–4.5	3.5–3.7	4.2–4.7
Total plant capital cost, US$/kW	1095–1150	950–1350	1160–1190

LHV – lower heating value

The newer high-temperature, high-pressure USC steam generation processes are based on the critical point of temperature and pressure where water and steam become indistinguishable. The higher temperature and pressure make the plant operation more efficient at converting heat to electricity. As a result, these plants can achieve a gross thermal efficiency as high as 45%, as compared with around 36% for subcritical systems. This results in a reduction in CO_2 of around 17%. This brings CO_2 emissions below 722 kg/MWh, well above what the US Environmental Protection Agency (USEPA) demands of new coal plants (Nalbandian-Sugden 2008).

USC technology achieves the highest efficiency and consequently uses less coal, resulting in reduced CO_2 emissions per MW generated. CO_2 emissions may be reduced by 23% per unit of electricity generated by replacing existing subcritical plants with SC/USC technology (Nalbandian-Sugden, 2008). For a 700 MW unit, operating for 30 years, with 7000 full-load hours operation and control technologies to limit emissions of PM to 50 mg/m^3, NOx to 2 mg/m^3, and SO_2 to 200 mg/m^3, a 1% increase in efficiency would reduce emissions by 2.4 million tonnes (Mt) CO_2, 2000 tons (t) NOx, 2000 tSO_2 and 500 tPM over the life of the facility (Balling and Rosenbauer, 2007). Figure 3 summarises the reduction in CO_2 emissions per unit of electricity produced as coal plants evolve into higher efficiency systems.

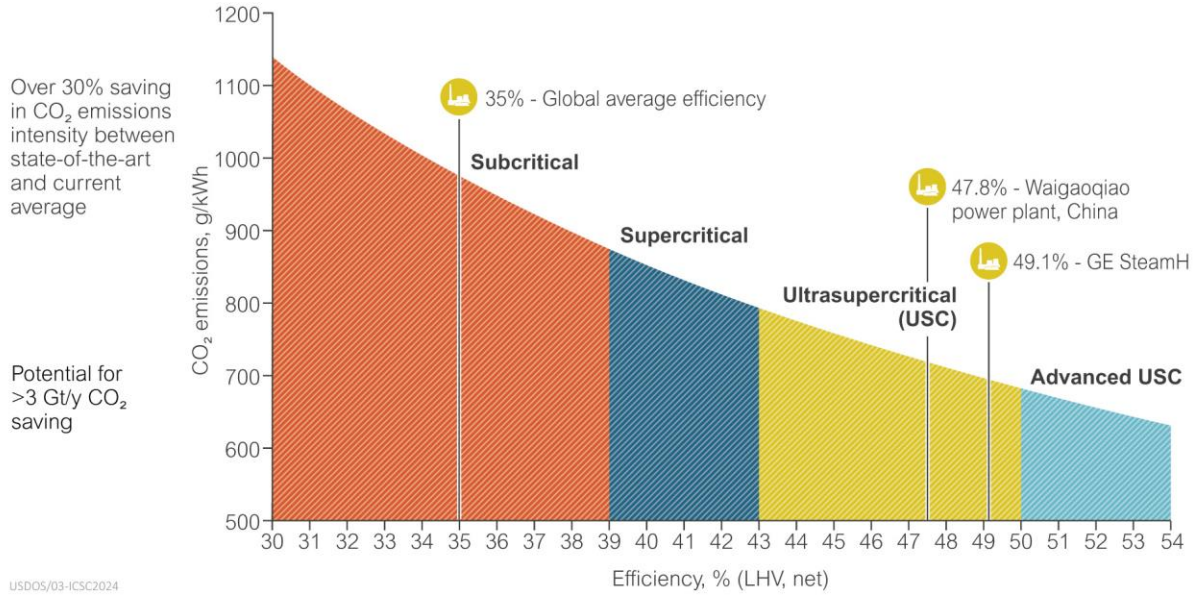

Figure 3 High efficiency coal-fired power plant technology (IEA, 2018)

There are many operational USC power plants in the world including in China, Japan and, more recently, India:

- **Isogo Thermal Power Station**, Yokohama, Japan (Boyd, 2013) is one of the most well-known USC plants in the world. The Unit 2 boiler generates a main steam pressure of 25 MPa at a temperature of 600°C, after which the steam is recycled and reheated to 620°C. This high temperature relies on boiler construction with advanced metals.
- **NTPC, Khargone (Madhya Pradesh)** (ET Energy World, 2019) has commissioned the country's first USC unit with a capacity of 660 MW. The plant operates at an efficiency of 41.5% (3.3% higher than conventional SC plant), with steam parameters of 600ºC and 270 kg/cm^2 pressure.

2.3 FACTORS AFFECTING PLANT PERFORMANCE

Even the best designed plants will perform below design parameters if there are significant variations from the planned mode of operation. As many countries increase the amount of variable renewable energy (VRE) on their grids, coal plants often have to modify their output to align with changes in demand to ensure grid stability. Since most coal plants were designed to operate at a steady rate, these changes in operation can lead to lower efficiency and potential plant damage.

2.3.1 Plant load factor

As one of the most common performance indicators, plant load factor (PLF) represents the utilisation rate of a plant's capacity for a given period of time. The CEA defines PLF as: the total energy sent out corresponding to scheduled generation during the period. It is expressed as a percentage of sent out

energy compared to installed capacity in that period and is calculated using the following formula (CERC, 2019):

$$PLF = 10{,}000 \times SG / \{N \times IC \times (100\text{-}AUX)\} \%$$

Where:

IC = Installed capacity of the generating station in MW

SG = Scheduled generation in MW for the time block of the period

N = Number of time blocks during the period

AUX = Normative auxiliary energy consumption as percentage of gross generation

In 2016, the average global PLF was 52.5%, with China and the EU slipping below the average at 49% and 46% respectively (Carbonbrief, 2020). India's national average PLF was 53.62% in 2021-22, showing a significant and steady decline from 83.9% in 2009-10. India's best operating PLF is 96.25%, recorded for the Sasan Ultra Mega Power Plant (3960 MW) (CEA, 2022b).

PLF also affects efficiency – that is, if a plant is not running at 100% load, then energy is lost. A study with an NTPC (major state-owned utility in India, formerly known as the 'National Thermal Power Corporation) plant proves that part load operation (with lower PLF) leads to the deterioration of efficiency across various power plant sizes and technologies, as shown in Figure 4.

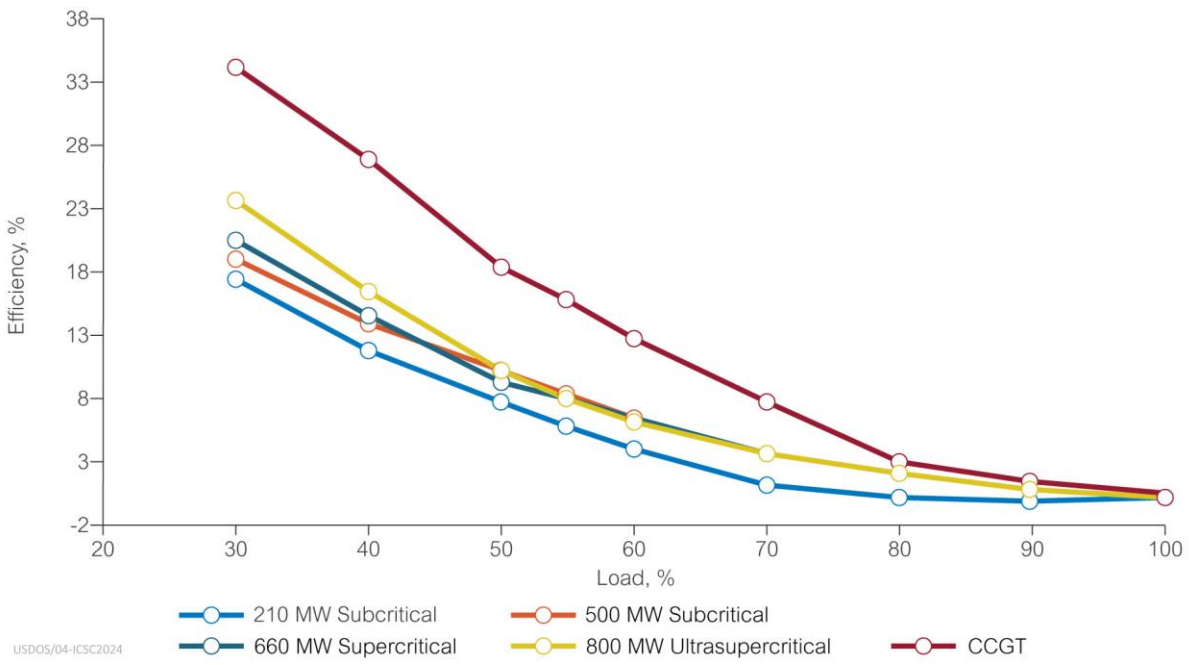

Figure 4 Deviation in efficiency with various load conditions (IGEF, 2020)

Variations in plant load can lead to other issues such as the lack of a consistent and economical coal supply and problems with long-term power purchase agreements. The need for these changes in plant operation are due to significant capacity addition (so more plants are available to be called upon) and

perhaps most importantly, the increase in obligations to use increased amounts of non-dispatchable renewable and non-fossil fuel-based power. However, India provides incentives to generating stations for the delivery of extra power. This equates to 0.65 INR/kWh (0.0078 $/kWh) for net output scheduled energy during peak hours and INR 0.50 paise/kWh (0.0060 $/kWh) during off-peak hours, calculated using the Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis within each season and under the Central Electricity Regulatory Commission (CERC) regulations (CERC, 2019). This means that plants which agree to operate in a more flexible manner are paid more.

2.3.2 Heat rate and efficiency

The plant heat rate represents the amount of energy used by an electrical plant to generate one unit of electricity. The ratio of the heat energy input in kcal (in the form of coal) required to generate one kWh of electrical energy at generator terminals is called the heat rate. The lower the heat rate of a thermal power plant, the better the performance.

Effective from April 2019, India has set a normative maximum station heat rate ceiling of 2600 kcal/kWh. Smaller units have higher ceilings, as shown in Table 4.

TABLE 4 HEAT RATE BENCHMARK (NPC, 2017; CEA, 2019; CERC, 2019; POWERMAG, 2022)

National average, kcal/kWh	Heat unit heat rate norm, kcal/kWh	Gross station heat rate ceiling, kcal/kWh	International benchmark, kcal/kWh
2592 (150<250 MW unit)	2600 (<200 MW unit)	2430 (200/210/250 MW sets)	2269 (8999 Btu/kWh) for 700 MW Longview Plant in West Virginia-USA)
2430 (250<500 MW unit)	2500 (<250 MW unit)	2390 (500 MW subcritical sets)	
2358 (500 MW unit and above)	2375 (250+ MW unit)		
	2250 (supercritical unit)		

Btu – British thermal units

SC units have a norm of 2250 kcal/kWh (CEA, 2019). CERC provides the norm for gross station heat rate as 2430 kcal/kWh for 200/210/250 MW sets and 2390 for 500 MW subcritical units and the weighted average of both for the entire station comprising multiple units. Units smaller than 200 MW have norms defined on a case-by-case basis. For lignite-fired plants, a correction factor for the determination of the heat rate norm is used based on the moisture content of the lignite:

- 50% moisture: 1.10 correction factor;
- 40% moisture: 1.07 correction factor; and
- 30% moisture: 1.04 correction factor.

For example, Neyveli lignite thermal power plants have the following norms (CERC, 2019):

- TPS-I: 4000 kcal/kWh;
- TPS-II: 2890 kcal/kWh; and
- TPS- I (Expansion): 2720 kcal/kWh.

Coal-fired power plant efficiency is inversely proportional to the plant heat rate. The percentage efficiency is expressed at a heat content of one kWh as a ratio of the amount of heat capable of generating one kWh electricity divided by the heat rate:

- Power plant efficiency, % = (3412 Btu/heat rate) × 100; where 3412 Btu = 1 kWh; or
- Power plant efficiency, % = (860 kcal/heat rate) × 100; where 860 kcal = 1 kWh

Table 5 shows the best Indian plant efficiency related to the international benchmark.

TABLE 5 PLANT EFFICIENCY BENCHMARK (NPC, 2017; ENERDATA, 2023)

Indian national average, %	Indian best, % (2013-14)	International benchmark, %
33.17 (150–<250 MW unit)	37.16 (150–<250 MW unit)	47.5 (RDK 8, Germany)
35.39 (250–<500 MW unit)	38.81 (250–<500 MW unit)	45.6 (Kozienice power plant, Poland)
36.46 (500 MW unit)	36.46 (500 MW unit)	

India has installed some high efficiency plants but there is still potential for improvement in terms of fleet average. As the country moves to ensuring that all new coal plants are HELE, and as older units close, the average plant efficiency will continue to increase. By keeping a watch on fleet heat rate and efficiency values, it will be possible to determine the poorest performing plants in order to prioritise them for closure or upgrade.

2.4 FLEXIBILITY OF POWER PLANT OPERATION

Demand for flexibility in coal power plant operations is largely driven by the onset of VRE on the grid and relative production costs. High penetration of VRE changes the electricity market demand for flexible operations and often forces thermal assets to change their mode of operation to deliver capacity at short notice, when VRE sources are not available.

Conventional coal-fired power plants, built for base load operation, are more efficient with higher capacity utilisation and lower production costs. However, they are increasingly used to balance the grid by decreasing minimum load and delivering higher ramp-up rates. Externalities such as regulatory requirements and fuel pricing can also significantly impact operational load demand. For a non-flexible plant, startup, and load following can result in significant damage in a short amount of time if process controls, safety interlocks, and protection systems are not optimised for the various modes of operation. Considering this, flexible operation demands a systematic approach, continuous

improvement, and a focus on proactive damage mitigation in various plant systems. Flexibility enables safe, efficient and event free and reliable operations (EPRI, 2020). The basic considerations of flexible operation are summarised in Figure 5.

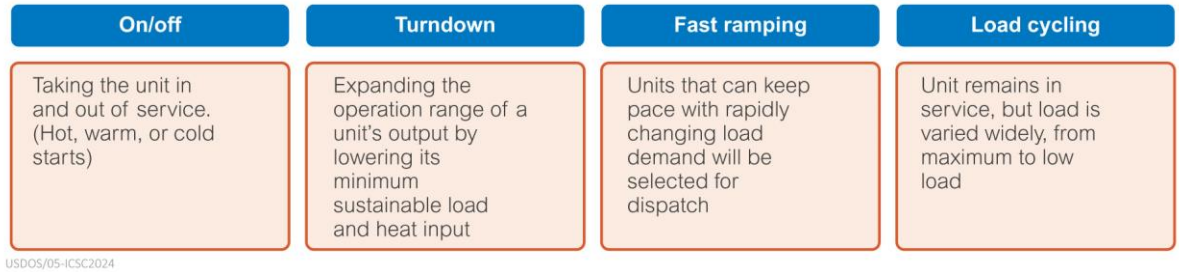

Figure 5 Basic operational flexibility in coal-fired power plants (EPRI, 2020)

Internationally, there is significant experience and evidence of reduction of minimum loads down to 25% and below. For Indian plants, there was initially significant apprehension that it may not be practically possible to achieve a stable load below 55% (Indo German Energy Forum, IGEF, 2020). However, CEA proposed draft 'Central Electricity Authority (Flexible operation of thermal power plants) Regulations' May 2022 (CEA, 2022a) to facilitate flexible operation in all coal and lignite-fired power plants in India. Once the regulation comes into effect, flexibility is required in all coal- and lignite-fired power plants with proven equipment, components, and assemblies, compliant with all applicable statutes, regulations, and safety codes with suitability assessment determined beforehand. According to the CEA draft, power plants shall be capable of providing the required output (minimum power load of 40–55%) as scheduled by the appropriate load dispatch centre. If required, power plants may implement necessary modifications in order to meet the regulation.

The CEA notification requires measures to lower minimum limits of power output, increase ramp rates, and optimise the start-up of the power plants based on technical feasibility studies in consultation with the concerned Original Equipment Manufacturers/Qualified Consultants. Table 6 summarises the parameters of flexible plant operation.

TABLE 6 FLEXIBILITY PARAMATERS (SINHA, 2020)

Flexibility parameters	Description	Present status	International benchmark	Target
Minimum load	Reducing the minimum stable load on coal (without secondary fuel support) to avoid frequent starts/stops. Also referred to as the turndown ratio	55–70%	15–25% boiler maximum continuous rating (BMCR)	40%
Load ramping	Rate of change of load (3% of BMCR/minute)	<1%	4% minimum (approximately)	3%
Start-up time	Time from light-up to synchronisation Hot 48 hours	Cold varies widely (6–10 hours) Warm 180–300 minutes Hot 120 minutes	Warm start light-up to base load 170 minutes	To match the start-up curve supplied by O&M (explore further reduction with retrofits/ operational optimisation). With Installation of condition monitoring system, there is scope for further reduction
Part load efficiency	Efficiency decreases with decreasing load. It is important to maximise the part load efficiency up to minimum loads to keep the operating expenditures at a minimum	Data of actual operating conditions are not available	Efficiency range 100% minimum load: reduction by 8%	Part load efficiency
Flexibilisation costs	With the intent to keep part load Opex low	Stations need to evaluate their cost of cycling	Typically, O&M costs increase 3–5%	Flexibility costs

BMCR – boiler maximum continuous rating

A number of different investments, system modifications/retrofits, system upgrades, operational procedural changes and policy changes can be made to increase power plant flexibility, with affordability and sustainability. However, there is no one-size fits-all approach to make existing power plants flexible. Based on global experience and studies carried out in Indian power plants, a range of strategies are available to achieve this goal. Every unit is unique in terms of age, make, historical operation, fuel type and design and specific measures will be needed. The retrofit solution is decided after a thorough cost-benefit analysis, following a test run and assessment of the expected regime of operation/ flexible operation the unit is expected to support in the future (Sinha, 2020). The trade-off between investment in flexibility upgrades and the returns achieved is summarised in Figure 6.

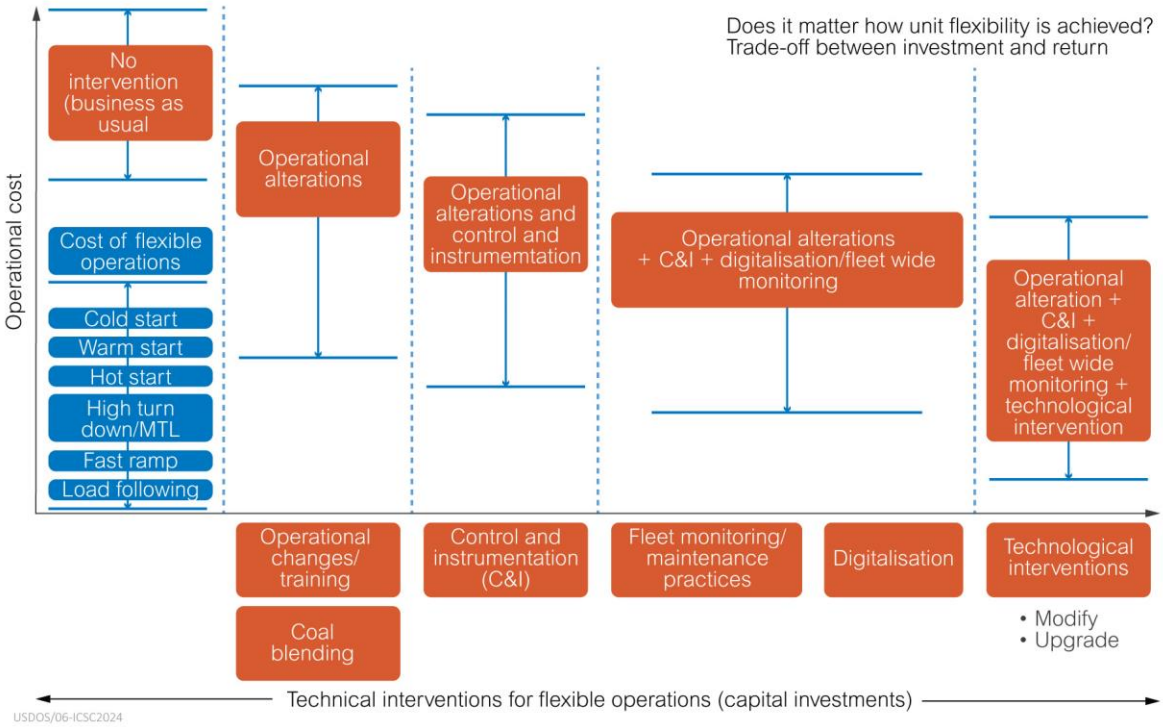

Figure 6 Flexibility strategy versus cost (Sinha, 2020)

With the addition of 175 GW of renewable energy capacity by 2022, India requires 60% of the installed fleet of power plants to operate at 55% minimum technical load (MTL). The Ministry of Power has set targets for achieving flexibility (55% MTL) of thermal power plants (coal and lignite) over a set period of time. The targets set are 20%, 30%, 40%, 50% and 60% of the total fleet compliant with 55% MTL between 2020 and 2024 (CEA, 2022a).

Field tests were conducted in three plants: NTPC Dadri; NTPC Mouda; and GSECL Ukai, for minimum load operation at 40%. For minimum load operation, stable combustion must be maintained by controlling the firing rates, uniform temperature distribution within the zones of the boiler and managing the synchronisation between the boiler and turbine (Sinha, 2020). NTPC Energy Technology Research Alliance (NETRA) has also demonstrated retrofitting on flexible control measures in NTPC Dadri plant Unit 6. The project was completed in July 2017 with significant improvement in unit primary frequency response and ramp rate (NTPC, 2023).

The US Electric Power Research Institute (EPRI) has developed a toolkit under the Power and Energy Efficiency Pillar of the US India Strategic Energy Partnership which was co-chaired by the United States Department of Energy (USDOE) Office of Fossil Energy and India's Ministry of Power. The toolkit is intended to assist management and technical personnel at thermal power plants to better understand the complexity of flexible operations and identify areas that need improvement. Guidance is provided for owners and operators of thermal power plants to assess flexible operations. The toolkit is a user-friendly instrument that comprises numerous pages of templates to be completed by the user

to collate specific information on the plant or unit being assessed. The High-Level Assessment tool guide is available for download https://www.epri.com/research/products/000000003002019900.

Each interactive template focuses on a different plant system or issue, with areas in which to highlight potential problems. There are currently ten templates for assessment and benchmarking within the toolkit, dealing with the parameters listed below:

1. Equipment operating modes;
2. Pressure part management;
3. Operations;
4. Maintenance;
5. Combustion and boiler performance;
6. Instrumentation, controls, and automation;
7. Environmental controls;
8. Cycle chemistry;
9. Turbine/generator; and
10. Balance of plant.

The simple template approach guides operators of these units on how to conduct complex assessments in a systematic, relevant, and detailed manner in order to reveal unit design and operating gaps, as well as to identify areas which need improvement. The templates are applicable to both subcritical and supercritical steam generators >100 MW.

The process of using the toolkit for flexibility management is summarised in Figure 7.

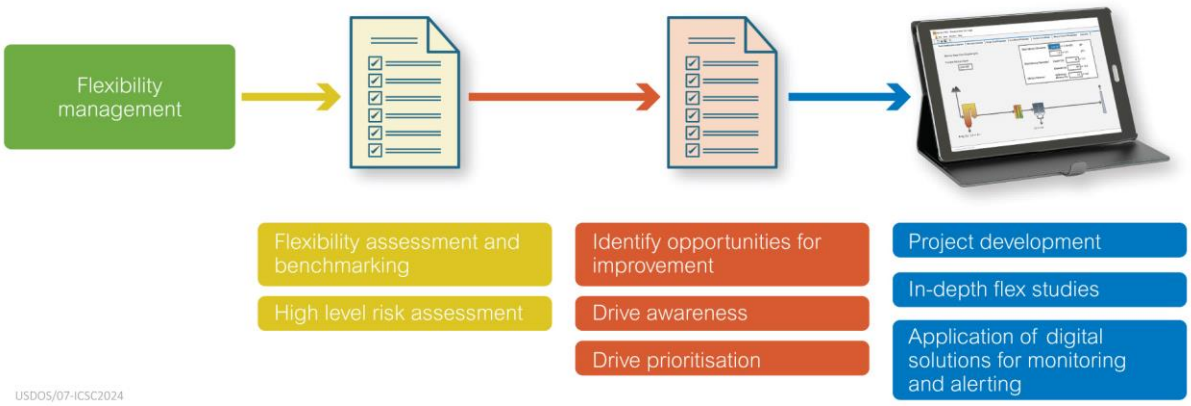

Figure 7 High-level flexibility assessment tool application (Sloss and Storm, 2021)

The flexibility management process begins with the completion of the templates using data and information directly from each coal-fired unit. A completed template enables an assessment of the current situation in each individual unit but also allows the development of baseline settings and benchmarking. Baseline settings mean a record can be kept of the status of each unit which will help to determine which areas of operation are running as expected and which need attention. If the templates of different plants are shared, this will allow units to determine their performance compared

with other units and promote the sharing of experience and expertise through benchmarking. By providing a 'living assessment', which can be updated regularly, the toolkit will allow operators to prioritise the most important maintenance issues. Over a longer period, the information in the toolkit templates will allow plant operators to consider long-term projects specifically suited to each unit. The data from these projects will help to further research into maximising plant flexibility and could feed into digital tools and models, which could facilitate faster responses to emerging issues across the entire Indian coal fleet in the future. More details on the flexibility toolkit, its operation and its applicability in India can be found in the complementary ICSC report by Sloss and Storm (2021).

2.5 CO_2 EMISSION REDUCTION PRACTICES

Excluding carbon capture (discussed in Chapter 5), energy efficiency improvement has the greatest potential to reduce CO_2 emissions from coal-fired power plants. There are several best practices in operation which reduce CO_2 emissions from the process. Plant efficiency can be improved through switching fuel but also through modifications in plant operation, such as (NPC, 2017):

- **Improvement in condenser pressure** – the condenser vacuum pressure plays an important role in the performance of a turbine and in ensuring maximum output. The desirable vacuum pressure in the condenser of a thermal power plant is 0.08 (kg/cm^2 absolute). An improvement in condenser vacuum of 0.01 kg/cm^2 is estimated to reduce fuel consumption by 1% for the same power output. The corresponding emission reduction for production of 1 million units (kWh) of electricity would be 7.57 tCO_2.
- **Reduction in excess air ratio** – excess air can be optimised by effective control of the air-to-fuel ratio. For the general operation of a thermal power plant boiler, the accepted excess air percentage is around 20%, but it can be further lowered to 14–15% to reduce dry flue gas losses. Controlling excess air to an optimum level guarantees a reduction in flue gas losses. For every 1% reduction in excess air, there is an approximate 0.6% rise in boiler efficiency. The corresponding reduction in emissions will be 4.5 tCO_2/GWh.
- **Reduction in the stack gas exit temperature** – the higher the stack temperature, the greater is the heat loss from the boiler. Effective heat recovery and draught control can reduce fuel consumption in the boiler. However, the flue gas temperature should not be reduced so much that it results in condensation on the stack walls. Every 22°C reduction in stack temperature would result in a 1% improvement in boiler efficiency. The corresponding reduction in GHG emission would be 7.57 tCO_2/GWh.
- **Optimising air preheaters** – as the pressure of air being heated is higher than the pressure of the hot flue gas duct, there is a possibility of air leaking into the flue gas path through improper sealing in the air heater or punctures in the tubes. This air leakage to the atmosphere not only effects heat recovery but also increases the load on the induced draught (ID) and forced draught (FD) fans. The effect is increased losses in the boiler and increased

power consumption in auxiliaries (ID and FD fans). Every 5% increase in air leakage would result in additional emissions of 0.57 tCO_2/GWh.

- **Cooling system performance improvement** – cooling water entering the cooling tower influences the condenser vacuum which in turn affects cooling tower performance through factors such as insufficient/excess cooling water flow, nozzles choking in the cooling tower basin resulting in uneven distribution of water, and algae formation in the cooling tower. Poor performance of cooling towers results in higher cooling water temperature going to the condenser. Every 30°C increase in the cooling water temperature impacts the condenser vacuum by 1 kPa (0.01 kg/cm^2), which in turn can lead to emissions of 7.5 tCO_2/GWh.

The National Productivity Council (NPC, India) recommends short-term, medium-term, and long-term best practices to improve power plant productivity and CO_2 emission reduction, as shown in Table 7.

TABLE 7 BEST PRACTICES FOR OPERATIONAL IMPROVEMENT IN A COAL-FIRED POWER PLANT (NPC, 2017)

Short-term best practices (implementation time – <3 months and payback time <12 months)	Medium-term best practices (implementation time – <6 months and payback time up to 3 years)	Long-term best practices (implementation time – <12 months and payback time >3 years)
Improvement in condenser pressure	Optimising air preheaters	Inclusion of a second reheat stage on the steam turbine
Reduction in excess air ratio	Optimisation of the combustion system	Replace the ash removal system with an efficient system
Reduction in the stack gas exit temperature	Cooling system performance upgrade	Increase in air heater surface
Optimisation of condenser	Flue gas moisture recovery	Installation of coal drying system
Optimisation of feedwater heaters	Reduction of slag and furnace fouling	Installation/improvement of process controls
Flue gas heat recovery	Steam turbine refurbishment	Introduction of super cleaning of turbine oil
Soot blower optimisation	Install a smart wall-blowing system for optimising	Life extension of coal mill gear-box lube oil by electrostatic liquid cleaning method
Steam leaks reduction	Wall blowing and improving heat rate	High-concentration slurry system for ash handling
Improvement in hot re-heat temperature	High-pressure turbine module replacement	Improvement of atmospheric condensate collections from all gas turbines' inlet air chilling system
Modification in auto furnace draught control logic of induced draught (ID) fan vane/scoop combination control	Boiler maintenance for minimising boiler tube failure	Gas turbine output improvement
Reducing slag formation in boiler	DeNOx water management	
Normalising economiser feedwater inlet temperature	Load rejection scheme implementation to avoid trips during gird disturbances	
Minimising auxiliary steam consumption and makeup water	Improvements and modifications to overcome plant recurring trips	
Fuel oil tank heating steam optimisation	Chillers performance improvement	
Application of 415 V variable frequency drive (VFD) for 6.6 kV motors	Fire hydrant system improvement	
Blinding one stage of a high-pressure boiler feed pump	Plant online performance monitoring system development and implementation for better monitoring and control	
Improvements in process monitoring and control, auto starts/stops logic for various drives	Optimising power consumption for plant extended shutdown preservation activities	
Providing solenoid valves for seal flushing requirement		
Substituting glass wool insulation for chilled water lines by polyurethane foam (PUF) insulation		
Providing a purging system for fuel nozzles to overcome fuel nozzles choking problems		

2.6 CASE STUDIES

The following sections provide examples of how coal plants can be modified or upgraded to increase efficiency and electrical output.

2.6.1 Case study 1: efficiency improvement at RDK Power plant, Germany

RDK (Rheinhafen-Dampfkraftwerk) Unit 8, in Karlsruhe, Germany, is a 912 MW coal-fired unit which started commercial operation in December 2013, demonstrating a net thermal efficiency of 47.5% – the highest of any coal plant in the world at the time. The efficiency comes from its high steam parameters of 600ºC/620ºC at the turbine entrance, use of newly developed materials (such as T24, VM12, and 25% chromium-austenitic materials), new turbine blades for increased internal turbine efficiency, and low condenser pressure due to continuous cooling with Rhine river water. The high efficiency helps the plant achieve very low specific CO_2 emissions of only 740 g/kWh and saved an estimated 275,000 t/y coal.

The plant has advanced pollution control technologies installed: electrostatic precipitators (ESP), flue gas desulphurisation (FGD), and selective catalytic reduction (SCR), as well as optimised combustion and operation. The efficiency of the entire system is increased by using a wet stack without re-heating the flue gas. The combination of electricity and heat generation with a district heating output of up to 250 MWth reduces the wastage of unused energy. Additionally, a 1.8 MW bulb turbine is installed to harvest hydropower from the cooling water returned from the plant. Hydropower exploits the 8.3 m average height difference between the turbine level and the water source of the River Rhine. For this, a gravity-fed basin has been integrated into the vertical duct of the cooling tower with a bevel gear bulb turbine just before the outflow to the river. A bypass line enables the operation of the power plant even if the water turbine is not available (World Energy, 2019).

2.6.2 Case study 2: boiler efficiency improvement at Suralaya

The Suralaya power plant in Indonesia has eight bituminous coal-fired subcritical units which began operation between 1983 and 2011. The boilers of the first two 400 MW units were upgraded by Babcock and Wilcox Power Generation Group to restore their efficiency, increase maximum steam flow, and extend their life while reducing NOx emissions and ensuring operation with varying quality of coal (Power Engineering International, 2012). The rehabilitation involved the redesign of the convection pass and combustion systems for NOx emissions reduction, upgrade of the pulverisers, and refurbishment of the air heaters. The benefit from the air heater upgrade was particularly noteworthy: the reduced leakage and lower exit gas temperature provided fan power savings of 1000 kW at maximum continuous rating for both units and a 0.7%-point improvement in boiler efficiency, giving 0.8% reduction in fuel consumption (Henderson, 2015).

2.6.3 Case study 3: reheat efficiency improvement at Nordjylland

A double reheat steam cycle, introduced in the late 1950s, is another technology with the potential to increase coal plant efficiency by up to 50% of the original value. An excellent example of double reheat steam cycle deployment is Nordjylland Power plant, Unit 3 (415 MW) 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. With high flexibility, the unit can also operate with as low as 20% load. 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 (Adams and others, 2021).

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 Pingshan Power Plant Phase 2 (1350 MW unit), where the net efficiency of 49.37% (LHV) has been achieved in December 2022 (Powermag, 2023). Similarly, the whole turbine train will be elevated in the Fuyang Power plant 2 (660 MW unit, under construction) with the efficiency expected to surpass the Pingshan Power Plant, Phase 2.

The application of advanced nickel (Ni) alloys in double reheat units is under consideration by the Japanese and Chinese R&D programmes with the potential to increase efficiency to 54% or more. The double reheat steam cycle may also prevent low pressure turbine blade erosion (Adams and others, 2021) by reducing the steam moisture content by almost 50% compared to single reheat. With low moisture content, the steam extracted for feedwater preheating can be increased to an optimum level (Nicol, 2015).

2.7 COMMENTS

One of the most cost-effective ways to reduce all emissions from a coal-fired power plant is to ensure that it is running efficiently. The more efficiently a plant operates, the more energy it will produce from one tonne of coal. Further, the less coal used per unit of power, the lower the relative emissions of all pollutants.

The design of coal plants is evolving to use higher pressure steam production with significantly higher efficiency. However, even older subcritical plants can reduce their emissions, and their plant running costs, by ensuring that the plant is operated correctly and by installing strategies such as heat-recovery systems whenever possible.

The rapid move towards renewables in many countries is not reducing coal output as much as would be expected and, in countries such as India, is actually resulting in the increased use of older, less efficient coal units to provide peak power. While this guarantees electricity supply, the additional stress on some older units may not be sustainable or desirable. Since cycling can have a major impact on plant reliability, grid stability can be negatively affected if the assets are improperly managed.

Plants operating in flexible mode may show wear and tear much earlier than predicted for the same plant running at baseload. In order to avoid equipment-forced outages for repair and maintenance, the plant manager must be more aware of the operational conditions of the plant and the potential stresses and damage to individual pieces of equipment. Some of this damage can be monitored and predicted but this often requires increased expenditure in terms of management practices, monitoring protocols and measurement systems. A plant can avoid significant outage and repair costs by being proactive in terms of management and monitoring. The benefits gained from being proactive will outweigh any costs of implementing plant improvements.

3 COAL HANDLING, PREPARATION AND PROCESSING

Significant quantities of coal are handled, prepared, and processed in a coal-fired power plant. Since Indian coals commonly have lower calorific values and higher ash contents, Indian coal plants consume higher amounts of coal than plants in other regions – around 16,000 tonnes per day (t/d) for a 500 MW unit at full capacity. Plants can also generate over 6000 t/d of ash. In order to provide consistent and dispatchable power securely, power plants are also required to store a minimum of 15–30 days of coal – this means that the typical Indian coal plant must store hundreds of coal. This coal is sourced from a coal mine or coal handling agency, delivered to the plant site, and transported from the plant gate to the in-plant coal storage facility. When required, the coal is then transferred to coal crushing and storage systems and finally transported to the coal mill prior to introduction to the boiler. Each of these stages is part of 'coal handling and processing' and each stage is prone to fugitive emissions and material loss. Best practices in coal handling and processing therefore encompass the use of efficient technologies and fugitive emission prevention and control measures. In India, raw material storage areas also have a significant impact on soil, groundwater, and surface water, especially during the rainy season.

At each of these stages, there is the potential for the loss of valuable raw material, adding to overall plant costs. Despite this, many plants could improve their raw material handling, preparation, and processing. In emerging economies such as India, work in these areas is mostly carried out by unskilled, contractual, and daily wage workers which may be associated with low levels of liability for the workers' occupational health and safety. Unless adequate quality assurance and quality control (QA/QC) requirements are maintained, the quality of work may be substandard. Compared to Western economies, India has relatively weak regulatory enforcement on arresting dust emissions from material handling areas and negligible monetary loss does not discourage mishandling.

The following sections briefly list the stages of coal handling and processing between coal mines and utility boilers, highlighting where best practices should be applied.

3.1 PIT-HEAD PLANTS

Pit-head plants, located at coal-mine sites, are considered to have advantages over other plants with respect to transport and handling. The mined coal is prepared, stored, and processed at the mine site for use in the plant so there is no long-distance transport, less associated material loss, and lower investment required in pollution control. In addition, the ash generated from the plant can be used for mine-filling, avoiding transport and utilisation challenges for bottom ash and fly ash.

The Central Electricity Regulatory Commission (CERC) has specified norms for transit and handling loss for coal use in power plants. The limits are 0.2% for pit-head plants and imported coal-based plants,

and 0.8% for non-pit-head plants (CERC, 2019). Usually, a 'merry-go-round' rail track system is installed at pit-head plants to move extracted and prepared coal from the mine site to the power plant. Examples of pit-head power plants in India are NTPC Singrauli, NTPC Vindhyachal, NTPC Rihand, OP Jindal Power and the Neyveli Lignite Power plants.

3.2 COAL TRANSPORT AND HANDLING

There are numerous stages through which coal passes from being mined to being fed into a coal-fired power plant mill and in many of these stages there is the potential to reduce environmental impacts.

3.2.1 Transport

For coal transport from mine to distant plants, shipping and rail transport are considered the best options, especially in regions such as India where road transport can incur delays and can add to local air pollution. Shipping is common for international bulk coal imports, where the coal is unloaded at the port or terminal, stored, and transported directly by conveyor to a coastal plant or by road transport for longer distances. In India, railway wagons are the preferred means to deliver to remote plants.

At the plant site, conveyors are frequently used for raw material transfer. Enclosed tube or pipe conveyors (Figure 8) are preferred as the system is designed to carry the material without exposing it to wind, rain or moisture.

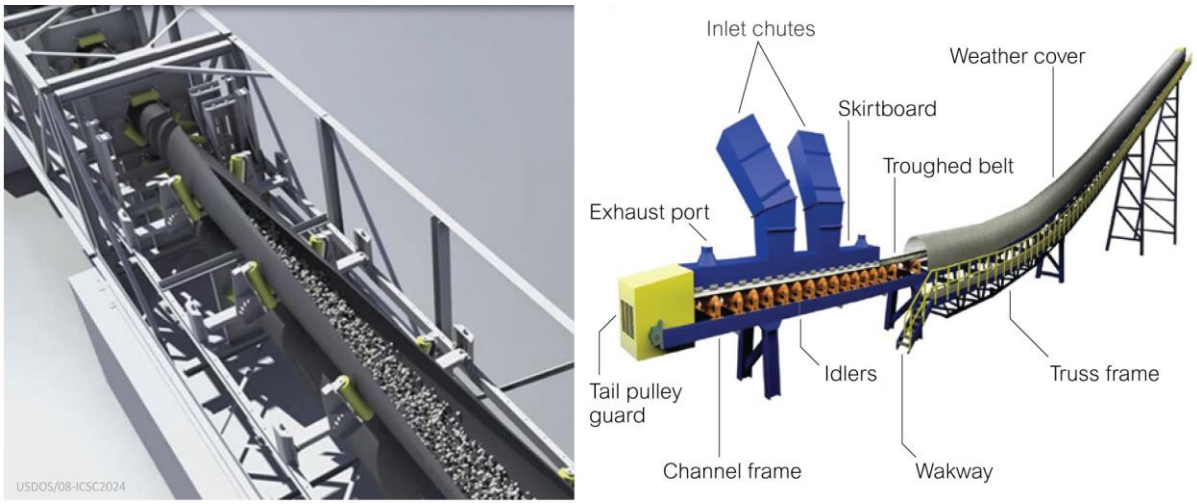

Figure 8 Tube or pipe conveyor and enclosed conveyor (Beumer Group, 2023; Feeco, 2023)

JSW Steel, Bellary, has the world's longest pipe conveyor (20.9 km) installed for iron ore transport from the Nandi Halli yard. For coal transport, 7.5 km and 7 km long conveyor pipes are installed at the Sembcorp Gayatri Power plant and O P Jindal Power plant respectively with shorter systems at numerous other sites (MACMET Engineering, 2023).

3.2.2 Coal unloading

Unloading points are a potential source of fugitive emissions. If the drop height between the delivery system and the site of the deposit is high, then dust release can be an issue. It is recommended that the drop height is kept to a minimum and the deposit point, whether final storage or a changing station, should be enclosed to avoid exposure to the high wind and rain. Airborne dust emissions during unloading can be controlled by creating negative pressure for dust collection and passing the dust-laden air through a bag filter for recovery of valuable raw materials. For dust suppression, water sprinkling, and dry fog systems are recommended. Frequent cleaning of spillages will maintain good housekeeping and workers should be provided with proper dust control masks and personal protection equipment.

Coal delivered through rail wagons commonly uses wagon tipplers or track hoppers to unload the coal at the enclosed plant site which should be equipped with a dust suppression system. As best practice, a weather enclosure shed should be installed over the tipplers and hoppers along with dust suppression systems covering the entire unloading process.

3.2.3 Coal preparation

Unloaded coal is sent through conveyors to crushers to prepare uniform-sized coal. Magnetic separators are used to remove pieces of metal and manual stone separators remove stones prior to coal crushing. Online coal analysers are installed to check the quality of the coal. Various types of primary and secondary coal crushers are available depending on the input coal quality and plant layout. In each step of the process, from the feeding point to the crusher, the crushing operation and crusher discharge points are potential sources of fugitive emissions. Bag filters with negative suction or, less commonly, wet scrubbers can be installed to capture the dust (CPCB, 2007).

3.2.4 Coal storage

Crushed coal passes through the conveyor to the stacker and reclaimer and then goes to storage. Ideally, the storage area should comprise a covered area, with a paved surface, stormwater drain and leachate collection, a dust suppression system, and a sensor to detect spontaneous combustion. Stockpiles can be of conical shape, ring shape, or longitudinal shape ensuring uniform layering without air pockets (Roker, 2018; Figure 9).

Figure 9 Covered coal storage with stacker reclaimer (Roker, 2018)

For open storage, the stockpile should be made in the direction of prevailing wind to lower surface exposure, covered with tarpaulin and/or with a wind curtain to control blow-off. The paved surface with stormwater drains and a leachate collection system prevents water pollution from the storage area. Thermal sensors are used to identify spontaneous combustion in the coal pockets which can be quickly separated and mitigated. Coal pile handling and control of spontaneous combustion are covered in more detail in a separate ICSC report (Sloss, 2014).

3.3 COAL BENEFICIATION

Coals can be improved in various ways, the most common being either washing or blending, as discussed briefly below. The ICSC has produced several reports on best practices in coal washing which are freely available from www.sustainable-carbon.org, such as Zhang (2021), Reid (2017) and Sloss (2014).

3.3.1 Coal washing

As Indian coal has a high ash content, the use of washed coal is considered best practice in India. Indian regulators advise plants to use coals with ash contents below 34% and for many Indian coals, this means that the coal must be washed. Ideally, coal washing should take place at the mine site as it enhances the loading capacity of rail wagons in terms of the energy content of the cargo. Moving only washed coal also reduces the premature wear and tear 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 the ash content of coals from 41% to 34% results in rail cost savings of 15%. By transporting less inert material, the fuel consumed per GJ of energy conveyed is also decreased, thus also reducing the CO_2 emissions from transportation. India has approximately

130 Mt/y of washery capacity (2017), of which approximately 100 Mt/y is for steam (non-coking) coal (CSO, 2018).

Gazette Notification GSR02 (E), dated 2 January 2014 and issued by the MOEFCC (2014) mandates that power plants of capacity of 100 MW or above located between 500–750 km and 750–1000 km from the pit-head shall be supplied and use coal with ash content not exceeding 34% on a quarterly average basis with effect from 2016 and 2015 respectively. Power plants located more than 1000 km from the pit head shall be supplied with, and use, coal with a maximum ash content of 34% on a quarterly average basis with immediate effect (2014) (CPCB, 2014). According to a 2023 press release from the Ministry of Coal, at present there are 20 operating coal washeries in India with a total capacity of 113.6 Mt/y (PIB, 2023a). This is estimated to be around 15% of the total coal consumption in the coal-power sector.

Case study: a 250 MW unit of NTPC's Satpura plant achieved significant benefits from using washed coal (34% ash) which included:

- an increase in PLF (*see* Chapter 2) from 73 to 96%;
- a reduction in coal consumption from 0.77 mg to 0.553 kg/kWh;
- a reduction in coal mill rejects from 0.35% to 0.033%;
- reduced PM emissions from 29.78 mg/m^3 to 17.23 mg/m^3.

These changes had no detrimental effects on boiler performance. Plant degrading issues such as slagging, boiler tube leakage, clinker formation, and abnormal erosion were not reported, indicating smoother operation in the plant (Adams and others, 2021).

APGENCO quantified the environmental benefits of using washed domestic coal (34% ash, 0.62% sulphur) compared with a blend of domestic raw coal (38% ash, 0.62% sulphur) and imported coal (16% ash, 0.8% sulphur) for a proposed 800 MW Vijayawada coal plant. Fuel consumption (t/d); and SO_2 emissions (gramme per second; g/s) fell by 14.6%, ash production (t/d) fell by 23.4%, while NOx emissions (g/s) declined by 41.9% (Adams and others, 2021). There is therefore significant potential for coal washing to contribute to emissions reduction in India.

3.3.2 Coal blending

For plants which are not located at a pit head, there is commonly a choice of coals from regional mines. For many plants, it will be possible to accept coals from a large number of mines which will help to ensure a reliable supply. If the coals are similar, then they may be simply stockpiled and used together. However, if the coals vary significantly in their characteristics, it may be necessary to monitor the coal mixes to ensure consistency so that there will be no damage to mills or injection systems, nor any detrimental effects on combustion performance.

Firing imported coal blended with indigenous coal was adopted by many coal-fired power plants in India to save on fuel costs and to reduce SO_2 emissions by taking advantage of India's low sulphur content coal. The blending began with a ratio below 15% by weight as this proportion does not require plant modification. Zhang (2021) reports that the CEA's April 2011 Guideline has recommended that all new coal-based projects be designed to blend domestic and imported coal up to a blending ratio of 30%. From 2012, Indian coal imports increased year-on-year. However, the Indian government announced that it would cease blending imported coal by March 2023 (Zhang, 2021). The timeline has subsequently been extended to March 2024.

The following case study is copied from the complementary ICSC report by Zhang (2021).

IL&FS Tamil Nadu Power Company Limited (ITPCL) is developing a 3180 MW thermal power plant in Chidambaram Taluk, Cuddalore, Tamil Nadu. Phase I of the project comprises 2 x 600 MW subcritical units, which were commissioned in September 2015 and April 2016. Phase II comprises 3 x 660 MW supercritical units which are under construction (2021). All the units are designed to fire imported Indonesian coal. However, due to the change of policy by the government to promote the use of indigenous coal, ITPCL proposed to use local lignite with imported coal in the two operational 600 MW units. The aim is to also reduce the operational cost and environmental impacts of the plant. The Indonesian coal imported by ITPCL is transported by ship to Karaikal Port, and then 128 km by rail to the power plant. ITPCL proposed to source indigenous coal from NLC India Limited (formerly Neyveli Lignite Corporation Limited). NLC India has four mines with a total lignite production of 30.6 Mt/y located about 25 km from Cuddalore power plant. Coal is blended in the ratio of 25:75 lignite/coal. Beds/stockpile blending and blending on moving belts are used as necessary using a suitable stacking area, conveyors, and track hopper system which are already available at most power plants. The characteristics of the imported coal, the Indian lignite, and the blend of the two are summarised in Table 11.

TABLE 11 CHARACTERISTICS OF COALS FIRED AT CUDDALORE POWER PLANT, INDIA (ZHANG, 2021)

Characteristics	NLC India lignite	Imported coal	Blended coal
Moisture, %	51	26–35	35.265
Ash, %	7.5	0.25–6	6
Volatile matter, %	23.5	32–41	–
Fixed carbon, %	19.75	27–32.75	–
Sulphur, %	0.85	0.13–0.4	0.8
Calorific value, MJ/kg	11.36	16.74–20.92	17.57

ITPCL assessed the environmental and social impacts and mitigation measures resulting from using a blend of lignite and coal. Some parameters for using imported and blended coal are compared in Table 12. The results suggest that no changes are needed in the plant configuration or boiler because the plant is designed to fire imported coal with a gross calorific value (GCV) in the range of 17.57–19.25 MJ/kg and the GCV of the blended coal is in the low end of the range at 17.57 MJ/kg. For the same reason, the quantity of blended coal required is estimated to be the same as the imported coal.

The existing stockyard can be used for lignite storage so there is no need for additional land. The ash content of the coal blend is the same as that of the imported coal, so no additional generation of ash is anticipated, and no extra ash ponds are needed. The power plant has installed ESP, wet limestone FGD, and low NOx burners as emissions control measures. Dust suppression measures include wind barriers, covered conveyors, covered transfer points, water sprinklers, and fitting the silos and track hopper with appropriate controls. With these measures in place, the emissions of pollutants from the power plant are below the national standards. The sulphur content in the coal should not exceed 0.8% to keep SO_2 emissions below the 200 mg/m^3 standard; this is achievable with the blended coal. As the same amount of coal is used, the requirement for desalinated water and seawater (for cooling) is not changed. The amount of discharge water remains the same.

TABLE 12 PARAMETERS OF IMPORTED AND BLENDED COAL AT CUDDALORE POWER PLANT, INDIA (ZHANG, 2021)

Parameter	Imported coal	Blended coal	Remarks
Coal requirement, t/h per unit	336	335.8	No change
Allowed sulphur content, %	0.8 with FGD	0.8 with FGD	No change
Ash, %	6	6	No change
Gross calorific value, kcal/kg	17.57–19.25	Average 17.57	Meets imported coal low
Station heat rate, MJ/kWh	9.83	9.83	No change
Ash generation, Mt/y	29,996.7	29,996.7	No change
Fly ash, kt/y	239.9	239.9	No change
Bottom ash, kt/y	59.9	59.9	No change
Ash pond area for 3180 MW, ha	107	107	No change
Coal requirements, days	30	30	No change
Lime requirement for FGD, t/d per unit	15	15	No change
Gypsum generation from FGD, t/d per unit	20	20	No change
Circulating water requirements (Intake), m^3/h	11,535 for 2 x 600 MW units	11,535 for 2 x 600 MW units	No change
Discharges/outfall, m^3/h	8,539 for 2 units	8,539 for 2 units	No change
Freshwater requirement, million L/d	10 for 2 units	10 for 2 units	No change
Furnace/boiler specifications/ modifications if any	Tangential fired water tube furnace	No modification	No change
Pollution control measures provided/considered	ESP, FGD, Low NOx burners	ESP, FGD, Low NOx burners	No change
Emissions, mg/m^3 PM SO_2 NO_2	 <50 <200 <300	 <50 <200 <300	No change
Traffic rate	5 trains per day	6–7 truck/h and 4 trains/d	
Total plant area, ha	478	478	No change

Best practices for coal washing and blending depend on the requirements of the plant. The desired quality of coal will be determined by the plant operator to ensure efficient and reliable plant performance. However, how the coal is beneficiated, through washing and/or blending, should be carried out in such a way that environmental issues such as new solid or liquid waste streams are avoided or minimised. This will need to be created as site-specific best practice.

3.4 COMMENTS

The extent and form of coal handling, preparation and processing are primarily determined by the source and quality of the coal in relation to the plant (taking into account the coal transport) as well as the coal characteristics specified by the plant. Coal washing is increasingly common in India to reduce the amount of ash which is transported and combusted at plants. However, coal washing creates environmental problems such as new solid and liquid waste streams and so must be carried out according to best practice. This should include:

- Carrying out as much coal cleaning and processing as possible at the site of production (mine). This reduces the amount of incombustible waste material being transported over long distances.
- Ensuring that coal washeries are operated to minimise dust, waste materials and water contamination.
- Evaluation of the entire transport route, from mine to plant, to ensure that steps are taken to minimise dust issues as well as loss (theft) or tampering with the coal during delivery.
- Blending of coals or lignite from different mines can create new mixes with advantageous characteristics for combustion and emissions control. This needs to be evaluated on a case-by-case basis and the blending process must be carried out in such a way as to reduce dust or waste issues.
- Stockpiles of coal should be protected to reduce dust issues and also potential groundwater contamination from rain runoff.

4 BEST PRACTICE IN WATER CONSUMPTION AT COAL-FIRED UTILITIES

Water consumption in a coal-fired power plant can be significant. Water is primarily used for cooling in coal-fired utilities, although it is also used in some ash handling processes. A small amount is used as boiler feedwater. Coastal plants commonly use sea water for cooling and, in some cases, for flue gas desulphurisation. Non-coastal, inland plants depend on fresh water and therefore often have to compete with other important fresh water users. Stress on water resources are higher in power plants with once-through cooling (OTC) systems which demand a huge amount of surface water compared to those with cooling towers which can recycle much of the water. Figure 10 shows the locations of water use in a typical coal plant.

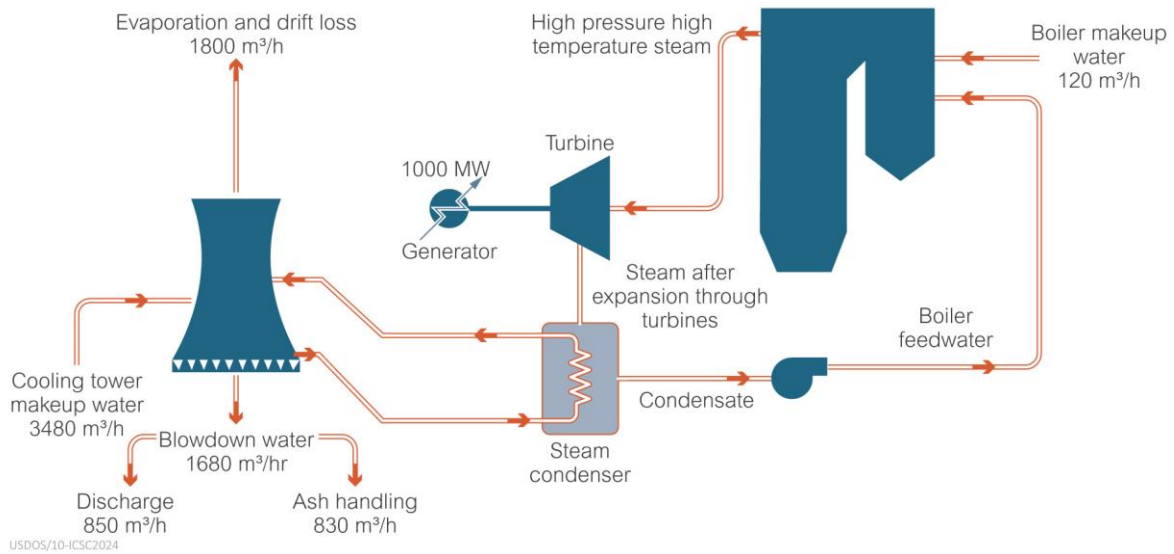

Figure 10 Schematics of water use in a typical 1000 MW coal-fired power plant (CSE, 2015)

Compared to other industrial activities, Indian coal-fired power plants are among the most wasteful consumers of water. Roughly 80% of the water demand is for cooling purposes, 18% for ash handling and 2% for process and domestic uses. However, this percentage varies widely from plant to plant. Overall, a plant with a cooling tower consumes an average 4 m^3 water/MWh compared with an average of 2 m^3 water/MWh in the USA, 1.34 m^3 water/MWh in South Africa, and 2.45 m^3 water/MWh in China. Some modern plants in water-scarce regions of the world have adopted air-cooled systems, which consume as little as 0.1 m^3/MWh (CSE, 2015). OTC power plants withdraw enormous amounts of water, up to 70–200 m^3/MWh, most of which is returned to the source (with around 1% lost in evaporation), but at higher temperatures.

For the first time in 2015, the MOEFCC stipulated water consumption norms of 3.5 m^3/MWh for existing cooling tower-based coal-fired power plants and 3.0 m^3/MWh (revised in June 2018) for those coming online from 2017 onwards. The OTC plants were asked to convert to cooling tower

operation. These norms were expected to be met within two years, along with other air pollution norms. However, many of these standards were delayed, as discussed in the complementary report by Sloss and others (2021), and the MOEFCC notification (MOEFCC, 2021). CSE's report *Water-inefficient power: implementing water norms and zero discharge in India's coal-power fleet* identifies the following Indian plants as having the lowest specific water consumption (CSE, 2021).

- Nabha Power Limited – 1.79 m^3/MWh;
- Sasan Power Limited – 1.9 m^3/MWh;
- KSK Nariyara – 2.05 m^3/MWh;
- Surat Lignite – 2.07 m^3/MWh;
- MB Power limited/Anuppur TPS – 2.2 m^3/MWh;
- Jaypee Bina Limited – 2.2 m^3/MWh;
- GMR Warora – 2.3 m^3/MWh;
- Adani Korba West – 2.35 m^3/MWh;
- Budge Budge TPS – 2.23 m^3/MWh.

A previous report from the ICSC (Carpenter, 2017) reviewed the international legislation on water use at coal-fired plants and provided an overview of the movement of water from the source, through the plant, to the various waste streams. Carpenter's (2017) report has more details on:

- wastewater in cooling systems;
- water use and reuse in flue gas cleaning systems; and
- water recovery from other streams (landfills, ash impoundments, coal piles and cleaning wastes).

In addition, Carpenter wrote a series of ICSC reports on water issues for coal-fired power plants, including *Water conservation in coal-fired power plants* (2017), *Potential water sources for coal-fired power plants* (2016) and *Water availability and policies for the coal power sector* (2015). Another ICSC report by Barnes (2019) reviewed the challenges with water availability in countries such as China, India, South Africa and the USA and summarises techniques and technologies to reduce water wastage and to identify alternative sources of water.

The sections below summarise the situation in India and the technologies which may be most appropriate for Indian utilities.

4.1 ALTERNATIVE SOURCES OF WATER

To avoid withdrawing valuable sources of water from public use, alternative sources of water have been identified and demonstrated as appropriate for use in coal-fired plants (Barnes, 2019):

- Wastewater from urban population centres;
- Seawater and low salt level sources;
- Water pumped from existing and decommissioned mines;
- Water pumped from oil and gas wells; or
- Deep saline aquifers.

As per the Tariff Policy, dated 28 January 2016, notified by the Government of India, sewage treated water is to be used for cooling water by thermal power plants which are located within 50 km of a sewage treatment plant.

Presently, seven thermal power plants comprising a total of around 9 GW are utilising 585 million litres per day (MLD) of treated sewage. These include – Koradi TPS, Khaperkheda TPS, and Nasik TPP Phase-I in Maharashtra; Pragati CCGP and Pragati-III TPS in Delhi; Bhavnagar Lignite TPS in Gujrat; and Yelahanka Combined Cycle Power plant in Karnataka. A further two plants (a total of 3580 MW) have ordered Tertiary Treatment Plant and Pipeline (90 MLD) to enable the use of treated sewage (CEA, 2024).

NTPC's Tanda thermal power plant has installed an ash water recovery system (AWRS). This system recovers around 150 m^3/h ash water, which is recirculated and used in the cooling system within the plant. The plant is working to expand the AWRS for an additional capacity of 300 m^3/h ash water recovery and reuse. The total water currently being discharged into the ash dyke is 842–850 m^3/h, which is almost 5–6 times the current ash water recovery and almost 50% of the total intake of water. Once the total AWRS is working and recovering 50% water from the ash dyke, this will reduce the plant's specific water consumption by approximately 20–25% (Tayal and others, 2016).

4.2 EXAMPLES OF ADVANCED WATER TREATMENT SYSTEMS

There are several commercially available water treatment systems available to reduce water use or enhance recycling. For example, the CoLD® process developed by Veolia Water Technology, is a simple and economical approach to zero liquid discharge (ZLD) and differs from conventional ZLD processes in that it requires no chemical treatment of the wastewater and generates no additional sludge for disposal. According to Veolia Water Technology (2022), it is an ideal solution to address stricter water reuse standards, mandated ZLD, and increasing regulation of discharge limits of total dissolved solids (TDS) facing the power industry.

The CoLD® process is the only method that results in direct crystallisation of highly soluble salts, including chlorides, nitrates, and salts of organic acids which are often produced by IGCC and wet FGD processes. The CoLD® process combines a conventional vacuum-forced circulation crystalliser with conventional heat pump technology to take advantage of the reduced solubility and boiling point rise (BPR) of high-solubility salts at low temperatures. Direct crystallisation of calcium chloride, magnesium chloride, ammonium chloride, or other high-solubility salts using the CoLD® process

eliminates the need for extensive pretreatment of the wastewater with lime, soda ash, and other chemicals to replace the calcium, magnesium, and ammonium ions in the wastewater with sodium ions so that a crystalline solid can be produced (USEPA, 2009). The process offers several benefits as it requires no chemicals, produces fewer solids for disposal, is a simple system with few unit operations, is robust and has similar energy requirements to conventional processes with a similar Capex and lower Opex.

Monfalcone Power Plant, Italy, a 330 MW coal-fired power plant, has installed the CoLD® process. At the Monfalcone plant, the conventional FGD ZLD system would have required softening, evaporation, and crystallisation and an Opex of $15.4 million and a net annual cost of $20.8 million. The CoLD® based ZLD needed only an evaporator and crystalliser with an Opex of $6.4 million and a net annual cost of $11.8 million. Considering the cost of chemicals and disposal, the CoLD® process was almost nine times cheaper.

HERO™ is a reverse osmosis-based process, specifically designed to treat aggressive feedwaters which often pose problems to conventional reverse osmosis processes. Feedwater with biological matter, oil grease, and silica can be captured and controlled. The HERO™ technology uses membrane scaling and endures higher recoveries to provide operational benefits and cost savings through reduced water consumption, use of anti-scalants and cleaning requirements (Water Online, 2023). The process yields ultra-pure water with maximum recovery (up to 90%). The purification process can handle high amounts of silica while consuming less water than conventional reverse osmosis (RO) systems.

A 520 MW natural gas-based combined cycle power plant in Arizona, USA has installed HERO™ which proved to be a suitable economical process to deal with the cooling tower blowdown, reducing waste by 90% and thus substituting a thermal brine concentrator at less than half the cost and with significant power saving. The 320 MW capacity Magnolia power plant (combined cycle) in California, USA and the 600 MW capacity Arlington Valley power station (combined cycle) have also installed the HERO™ system for ZLD (Aquatech, 2023).

For more information on water-saving and recovery systems please see the ICSC reports by Carpenter (2015, 2016, 2017) and Barnes (2019).

4.3 COMMENTS

Water is a valuable commodity and the operation of coal plants is evolving to reduce water wastage and to find alternative sources. By recycling as much water as possible within the plant, the need for additional sources is reduced. Treatment of wastewater is also increasingly important as legislation on liquid effluents continues to tighten. For India, the recovery of water from both internal plant waste (ash piles) and external waste (sewage treatment systems) has been demonstrated at full scale.

5 EMISSIONS REDUCTION

Coal-fired power is one of the most air-polluting sectors in India, contributing nearly 60% of PM emissions, 45% of total SO_2, 30% of total NOx, and more than 80% of total mercury emissions from all industrial sectors in the country in 2020 (CSE, 2020a). The MOEFCC stipulated emissions limits for these pollutants in December 2015 to be met initially within two years. As mentioned earlier, the implementation of these norms has been significantly delayed. A previous ICSC report: *Status of continuous emissions monitoring systems at coal-fired power plant in India* discussed the implementation delay in detail (Sloss and others, 2021).

Prior to the 2015 limits, there had only been emission standards for PM at Indian coal plants. The norms for SO_2, NOx, mercury emissions and water usage of coal-based thermal power plants were new and were relatively challenging, requiring a technology leap for compliance at many plants. The emission limits are summarised in Table 8.

TABLE 8 CURRENT EMISSIONS STANDARDS FOR COAL-FIRED POWER PLANTS IN INDIA (ADAMS AND OTHERS, 2021)

	PM, mg/m^3	SO_2, mg/m^3	NOx, mg/m^3	Mercury, mg/m^3
Old standard	150–350	None	None	None
2015 Norms (limits)				
Units installed before 31 December 2003	100	600 (<500 MW 200 (≥500 MW	600	0.03
Units installed between 2004-16	50	600 (<500 MW) 200 (≥500 MW)	300 450*	0.03
Units installed from 1 January 2017	50	100	100	0.03

* relaxed in 2020, as outlined in the text below
Note: PM, SO_2, NOx and mercury units in are in mg/m^3 which is assumed to be normal cubic metre, Nm^3

A variety of primary and secondary technology options are available for emissions control of air pollutants. Primary options include combustion optimisation whereas secondary options relate to flue gas cleaning with technologies such as ESP and FF for PM emission control, FGD and dry sorbent injection (DSI) for SO_2 emission control, and selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) for NOx control. Emission control for mercury usually comes as a co-benefit from other emission control technologies although additional reagents or technologies can be applied for tighter emission limits or challenging coals.

The following sections focus on the most appropriate technologies to control the major pollutants from Indian coal-fired utilities. A short section on CO_2 capture is also included to cover all relevant emissions.

5.1 PARTICULATE CONTROL

The installation of PM controls is commonly the minimum requirement for emission control at any coal utility plant. ESP or FF are the two major technologies applied worldwide. Hybrid systems such as wet ESP or electrostatically charged FF have emerged in recent years for specific applications, largely for achieving ultra-low emission limits. Since the emission limits in India are not 'ultra-low', these advanced systems may not be considered part of a cost-effective PM emission control strategy in India. Rudimentary PM controls, such as cyclones or settling chambers, do not apply to utility-scale coal-fired power plants, so are not discussed here either.

5.1.1 Electrostatic precipitators

An ESP captures PM in the flue gas by means of electrical attraction. The system (shown in Figure 11) is primarily made up of gas distribution plates, discharge electrodes, collection plates and rappers. The gas distribution plates are perforated plates which help maintain proper flow distribution of the entering gas stream. The discharge electrodes are divided into a number of fields (from 3–14) in series.

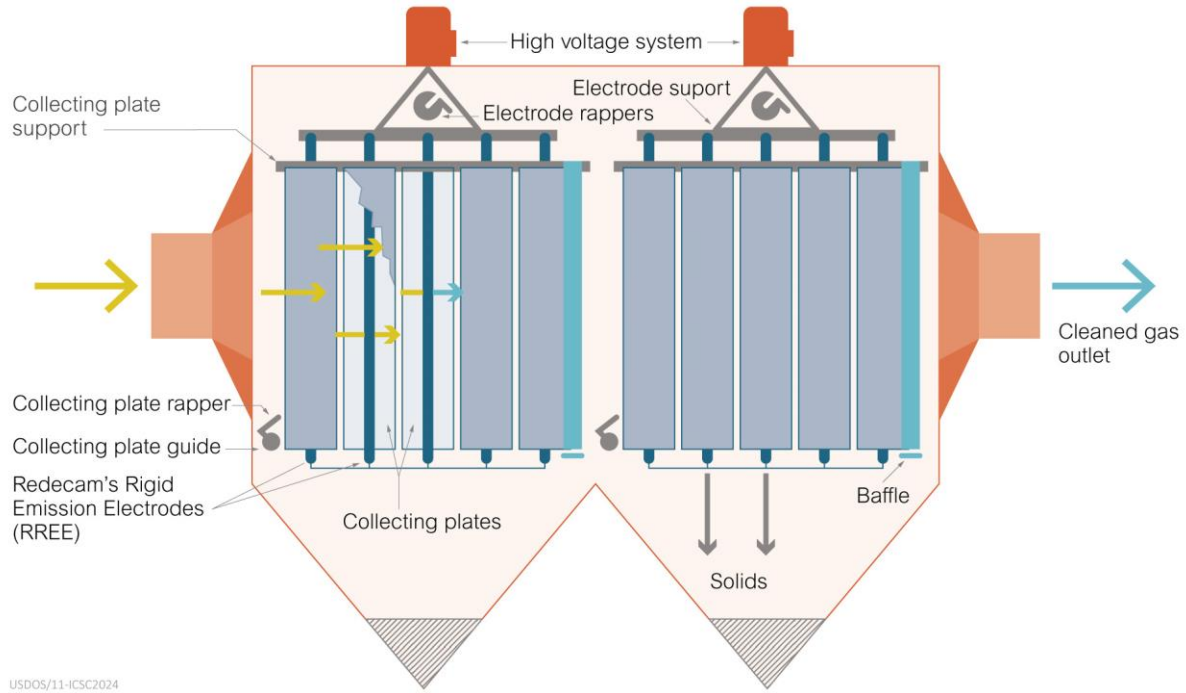

Figure 11 Diagram of a typical ESP (REDECAM Group, 2021)

As flue gas enters the ESP, the dust particles in the gas collide with the free electrons available between the electrodes, receiving a negative charge. The collection plates or pipes are positively charged which provide the collection surfaces for the negatively charged dust particles, as shown in Figure 12. The rapping or brushing system moves the PM from the collection plates into the hopper. In wet ESP (generally used in chemical and mineral processing industries), a water spray replaces the rappers and brushes.

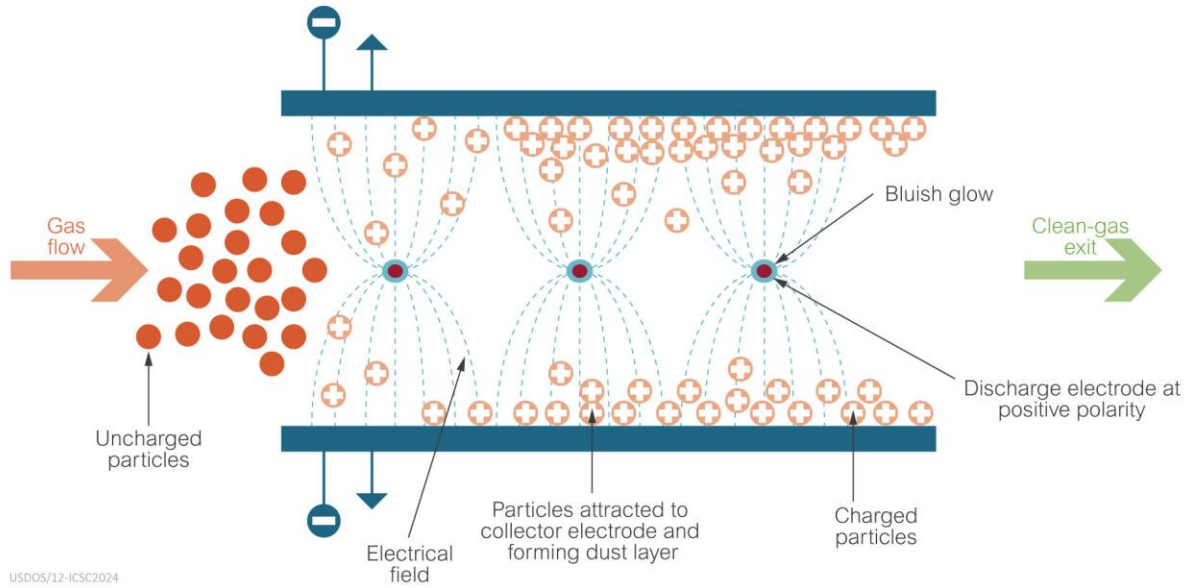

Figure 12 Schematic of ESP process of duct collection (Afshari and others, 2020)

ESP generally achieve an overall PM removal efficiency of 95% or more. Indian coal-fired power plants prefer to use ESP (over FF), due to the nature of the flue gas and quantity of ash generated from the process. ESP are also economical to maintain, have lower capital costs than FF, and have the flexibility to be operated over a wide range of temperatures, pressures, and PM load conditions.

Although many publications assume a 98-99% ESP collection efficiency, the actual PM control value achieved depends on multiple factors including:

- the coal ash content;
- the resistivity of the fly ash;
- the unburnt carbon in fly ash;
- the ESP size relative to PM loading in the flue gas; and
- the ESP operating conditions.

ESP may perform poorly due to operation and maintenance problems. This can be due to human error such as the bypassing of dust removal systems to avoid labour costs. There may be installation errors such as the mismatch of the fly ash evacuation system and the ESP ash dislodging capacity which can result in hoppers being damaged. Electrode misalignment and structure deformation can also affect capture performance. Discharge electrodes may suffer mechanical damage when the system is operated at an inappropriate voltage which leads to sparks, in turn causing erosion of the electrodes.

ESP have a lower removal efficiency when operating on flue gases with high resistivity fly ash. However, in modern systems fly ash resistivity is reduced with conditioning additives such as SO_3 and the resulting PM collection efficiency is improved. ESP are most effective for particles larger than 1 μm in diameter. However, ESP cannot efficiently collect submicron particles. ESP may also experience operational problems with moist or sticky PM which can form deposits on the collection surfaces.

These deposits will lower ESP performance and must be removed during scheduled maintenance. This requires the shutdown of the ESP to allow entry and manual cleaning of plates as well as repairs or replacement of mechanical and electrical components. Proper maintenance of the existing ESP is of paramount importance for assuring its performance according to design specifications.

Some plants may need to upgrade their ESP to meet tightened emission limits, and this will be carried out on a case-by-case basis to meet the plant-specific requirements. Options include (CSE, 2016):

- **Installing additional fields in series**: This is a common option to increase the collection area of an ESP but requires additional space on site.
- **Installing an additional ESP parallel to an existing ESP**: This can help in situations when adding fields is not possible. However, it requires the redesign of the flue gas flow and more power.
- **Increasing the ESP height**: When the plant footprint is limited, building upwards can be the best option. This adds to the specific collection area with increased space between the electrodes and the high-frequency transformer and rectifier without affecting the foundation load.
- **Use of dummy fields of ESP**: During installation, some ESP systems include unused fields which, if fit for purpose, can be upgraded with functional electrodes.
- **Installing a new ESP**: This may be the only option for ESP systems which are not appropriate for upgrade due to age, size, or other limitations.

There are also options for operational improvements to ESP, such as optimisation of the power supply by lowering the ripple voltage, introducing more bus bars and transformer rectifier sets to increase the corona power, and flue gas conditioning by using reagents (as mentioned above). It is also possible to introduce an FF into an existing ESP casing.

It is important to note that, if a plant is planning to install an FGD system, then the combination of ESP and FGD could mean that the ESP size can be reduced. Multipollutant strategies like this will also promote mercury reduction through enhanced co-benefit effects (CSE, 2016).

India's PM emission norms are not challenging for a modern coal-fired power plant. However, in older units, where the ESP performance has deteriorated, an upgrade using the options listed above may be required. The estimated cost for upgrading an ESP is Rs 15–20 lakhs/MW ($20,000–27,000) (CSE, 2020a).

5.1.2 Fabric filters

Fabric filters (FF), also known as baghouses, have similar PM removal efficiencies to ESP but typically are more effective for the removal of smaller particles. This is due to the longer residence times (minutes) of particles on the filtering fabric than in the average ESP (seconds). Additionally, FF are

more efficient than ESP in capturing mercury, which may be physically or chemically bound on the surface of fly ash particles. FF are not suitable for wet flue gases, potential temperature surges, corrosive gases, sparks, and soot. FF are generally more expensive than ESP based on cost per kW because they are technically more complex. Because of the unit-specific advantages of ESP and FF, some plants may choose a hybrid system to obtain the required PM removal efficiency at optimum operating conditions while controlling the cost.

The flue gas passes through rows of fabric bags in a baghouse and the fly ash is sieved from the gas phase. Filter bags can be made from various materials such as polypropylene, polyester, fibre glass, or Teflon and are selected specifically for the plant application and factors such as operating temperature, flue gas properties, and fly ash characteristics (FLSmidth, 2022). The fly ash is deposited on the filter bag until it forms a cake. This cake formation results in a pressure drop, at which time the bag is rapped or shaken, and the filter cake drops into the hopper below. The two most often used methods of cleaning the bags are pulse-jet or reverse air blowing. The typical configuration of an FF is shown in Figure 13.

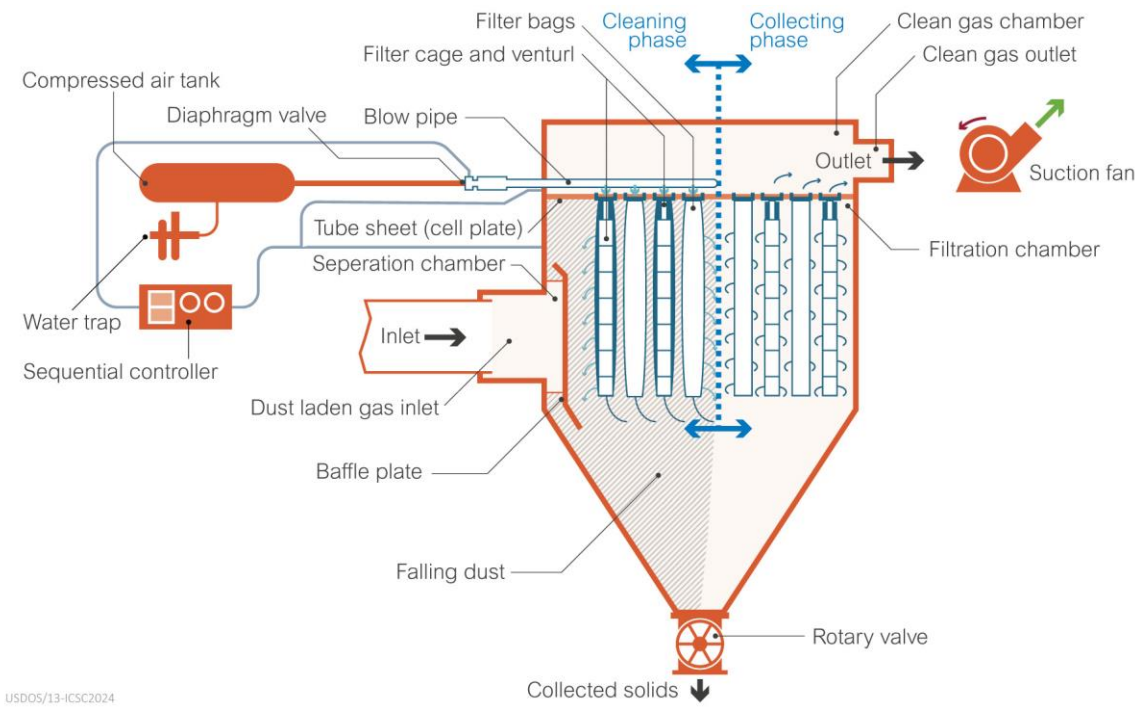

Figure 13 Schematic of a fabric filter (PASI, 2022)

There are three common types of FF, which vary by how the baghouse is cleaned, and the dust collected (Figure 14):

- Pulse-jet FF are preferred as they are the most efficient option (99.9% PM capture). In these systems, the dust-laden flue gas is sucked in from the bottom and pulled upwards; the dust is then captured on the exterior surface of the wire-cage-supported bag filters and clean gas passes through as exhaust. A solid-state timer, sequentially, gives pulses of compressed air in

the reverse direction causing a ripple effect which dislodges and releases the dust cakes which have settled on the bag filter. This type of FF does not need to be shut down for cleaning.

- Shaker FF have a lower efficiency than pulse-jet systems FF. The flue gas enters the bags from the bottom, is pulled upwards and the dust is collected on the inner surface while the clean gas leaves from the top. The collected dust is shaken from the bags at regular intervals. Periodical shut down (plant taken off-line) is required for mechanical shake-cleaning.
- Reverse FF use reverse air generated by a fan or blower and directed by a rotating arm over the bags to remove dust from the exterior surface. This is a low-pressure, high-volume cleaning system which self-cleans while online and decreases wear and tear. Although it saves on compressed air costs, the energy requirements and maintenance costs of the reverse air blower and moving parts are higher than for other FF options. Older designs of reverse air FF systems required offline cleaning and were constructed with multiple compartments (therefore bulky and more costly) to avoid taking the entire FF offline at once (CFE Filters, 2022).

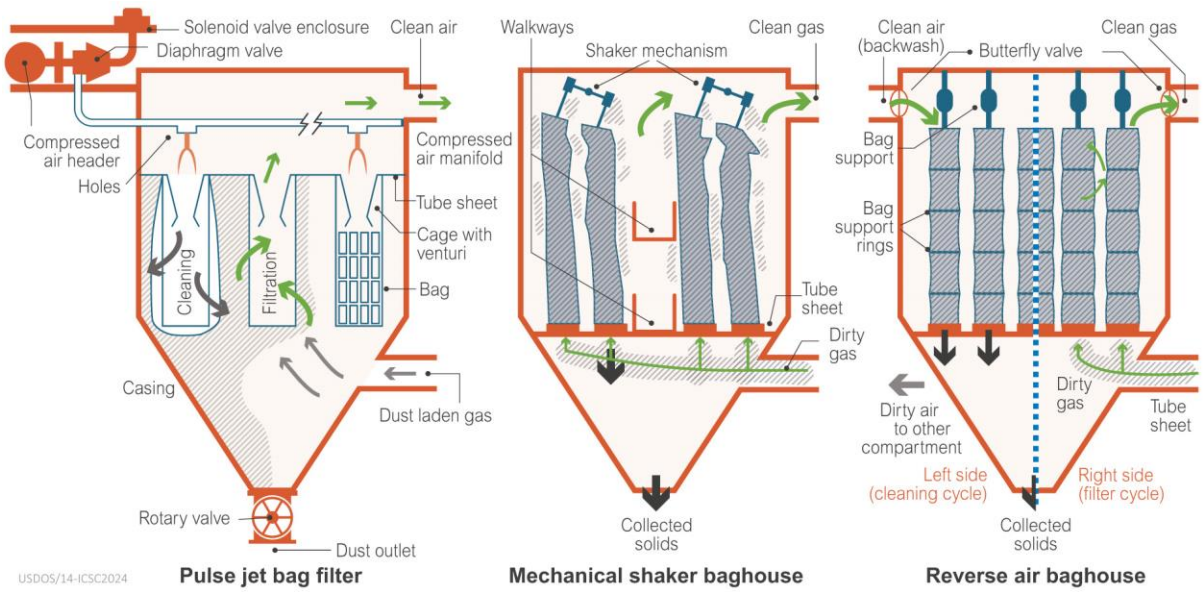

Figure 14 Different FF designs and configurations (Shah, 2017)

The efficiency of PM capture in an FF depends on the inlet flue gas temperature, gas volume, gas composition and the filter load. The filter load is described as the air-to-cloth ratio or volume of flue gas flow passing over a specific area of fabric filter material. The filter load, type of filter medium, construction, size, and shape of the system all influence the pressure drop in FF, which can, in turn, affect the PM capture efficiency and performance.

An FF with over 99.9% PM capture efficiency can achieve outlet PM emission concentrations as low as 10 mg/m^3. However, there are operating boundaries such as the flow rate: of 300 to 1,800,000 m^3/h; temperatures above dew point and <135°C (basic set-up); and in-coming concentrations of 0.1–230 g/m^3. FF needs filter fabrics at 11–17 m^2 per 1000 m^3/h (though this depends on quality and

application) and compressed air. Energy use varies between 0.2–2.0 kWh/1000 m^3 (0.2–3% auxiliary overall) and the cost may range from $1000 to $3000 for 1000 m^3/h (higher rate for lower overall capacity) with filter material costs ranging from 10–50% of the overall cost (emis VITO, 2020).

In addition to being more efficient than ESP, FF are more suitable for the removal of fine PM and are less sensitive to fly ash properties. FF are also available in modular options which allow for easier future expansion. Unlike ESP, fly ash resistivity does not affect the performance of FF. Catalysts such as vanadium and titanium can be incorporated into the FF bags for the destruction/removal of trace pollutants such as dioxins and furans, volatile organic compounds, polychlorinated biphenyls, and other chlorinated compounds. Bags can also be specially fabricated to capture mercury while not contaminating the ash cake.

A preventative maintenance checklist should include periodic inspections of the cleaning system, collection hoppers, and collection bags. Increased pressure drop across the FF can indicate the incorrect amount or undesired properties of PM collected on the filter media and can signal the condition of the bags themselves. Newly installed filter bags have the lowest pressure drop. Keeping a daily log of differential pressure starting with a new filter bag installation helps to diagnose problems. Regular inspection and maintenance are critical to ensuring that FF operate as designed.

5.1.3 Advanced PM control systems

The **moving electrode ESP (MEEP)** by Mitsubishi Hitachi Power Systems Ltd (MHPS) is an advanced ESP in which the ESP fields are retrofitted with a moving/rotating field which moves the dust collection surface past brushes to remove the particulates. The MEEP system is reported to occupy less space and does not have the dust resistivity issues of a traditional ESP system. It is installed in the last one or two fields of an existing ESP where there is low fly ash loading and therefore needs no extra space for expansion. Results from 30 installations in Japan have shown collection efficiencies up to 99.4% with highly resistive fly ash and half the site footprint of a conventional ESP. Installation in NTPC, Rihand (2 x 500 MW) has achieved emission reduction from 500 mg/m^3 to 50 mg/m^3 (MHPS, 2017).

The **electro-mechanical double-sone ESP** by Fujian Longking (China), separates the charging zone from the collecting zone, with both zones having a separate power source – this allows a high voltage direct current of 80 kV without sparking. The technology has high collection efficiencies for resistive finer fly ash (PM_{10} and $PM_{2.5}$). Installation of this system at the Xiamen power plant (300 MW units) in China has shown increased collection efficiency from 99.025% to 99.69%. Similarly, installations at the Henan power plant have shown an increase from 98.62% to 99.96% (34.6 g/m^3 inlet to 13.8 mg/m^3 outlet) and 99.92% (35.2 g/m^3 inlet to 28.1 mg/m^3 outlet). Fujian power plant (660 MW unit) retrofitted electro-mechanical double-zone ESP in the second field of a five-field ESP and has shown an increased collection efficiency from 99.62% to 99.81% (Nicol, 2013).

EPRI developed several advanced PM capture systems in the 1990s, including the Compact Hybrid Particulate Collector (COHPAC) and the TOXICON process. Both these systems showed enhanced PM capture efficiencies along with the potential to employ sorbents such as activated carbon to enhance the capture of species such as chlorine and mercury.

5.2 SO_2 EMISSION CONTROL

Sulphur is present in coal as free pyritic sulphur and organic sulphur bound to carbon atoms and is the source of SO_2 emissions from coal-fired power plants. Coal washing can remove pyritic sulphur but not the organic sulphur, which is converted to SO_2 during combustion. For SO_2 emission reduction, a power plant may either shift to using low sulphur fuel or select appropriate control measures. SO_2 emissions can be controlled at three places in a coal plant:

- **Pre-combustion**: sulphur (pyritic) content in the coal can be reduced through coal washing;
- **During combustion**: injecting sorbents into the boiler, usually for circulating fluidised bed combustion systems (CFBC); or
- **Post-combustion**: FGD or DSI.

FGD is the most popular SO_2 control technology, whereas pre-combustion and combustion modification techniques can help to a limited extent. For example, Indian coal has a relatively low (0.4–0.6%) sulphur content but also a low calorific value and high ash content, raising SO_2 emissions per unit of power generated. In India, using low sulphur coals and coal-washing will have limited benefits. Similarly, the sorbent injection option is not suitable for most common PC combustion-type boilers; it is suitable for CFBC-type boilers only. The most appropriate option for India is thus to consider flue gas treatment through FGD or DSI.

5.2.1 Flue gas desulphurisation

FGD is globally the most popular and proven post-combustion SO_2 control technology, and is widely installed across the USA and China. Both wet-type FGD and dry-type FGD options are available.

Wet FGD is the most commonly used process with an SO_2 removal efficiency of more than 90–95%. Based on the reagent used, the wet FGD process can use seawater or chemical reagents. Wet FGD systems commonly use limestone [$CaCO_3$, $Ca(OH)_2$] as the reagent as it is versatile and used for large-scale operations. Ammonia-based reagents (NH_3, NH_4OH) can also be used, as well as magnesium-based [$Mg(OH)_2$, $MgCO_3$] and sodium-based (NaOH, Na_2CO_3) reagents for smaller boilers and industrial ones. These latter options have high wastewater generation and a medium to high cost compared with limestone (Kortell, 2016).

In a limestone-based wet FGD, limestone (CaO) from the silo is crushed in the mill and then made into slurry in a slurry tank before it is pumped into an absorber vessel from where it is sprayed over the flue gas, as shown in Figure 15. The reagent reacts with the SO_2 in the flue gas and forms calcium

sulphite and then calcium sulphate ($CaSO_4.2H_2O$ – gypsum). In this process, acidic species in the flue gas, such as HCl and HBr, are also removed. At the top of the system, in the mist eliminator, the drops carried from the absorption zone by the flue gas are returned to the process. At the outlet of the absorber, the clean gas is saturated and can be removed directly via a cooling tower or wet stack. Optionally the clean gas can be heated and routed to a dry stack. The slurry collected at the absorber sump is also recirculated. The gypsum slurry collected from the bottom of the absorber passes through hydrocyclones and a filter press for dewatering and separation of the gypsum cake. Based on the requirement, gypsum can also be treated for use as a marketable product.

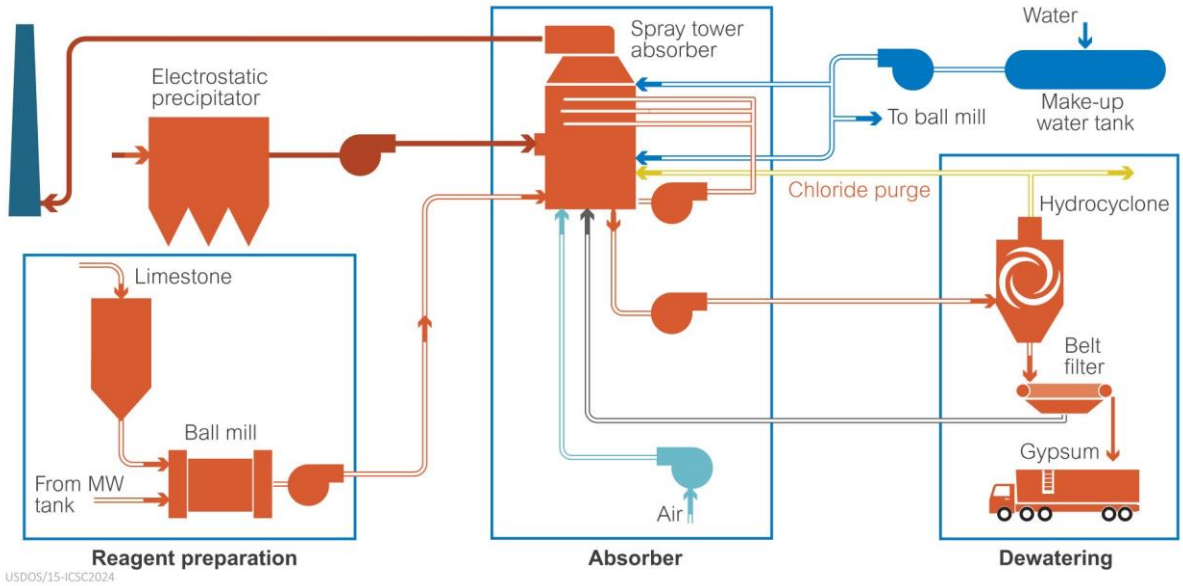

Figure 15 Schematics of limestone-based wet FGD (CSE, 2020b)

The ammonia-based version of this technology is similar to limestone, although the ammonia (NH_3) comes in liquid form and therefore does not need milling or making into slurry, as shown in Figure 16. Instead of gypsum, ammonium sulphate [$(NH_4)2SO_4$] is the by-product. The amount of ammonia required is around half the amount of SO_2 to be removed. The resultant ammonium sulphate by-product produced is around twice the amount of SO_2 removed.

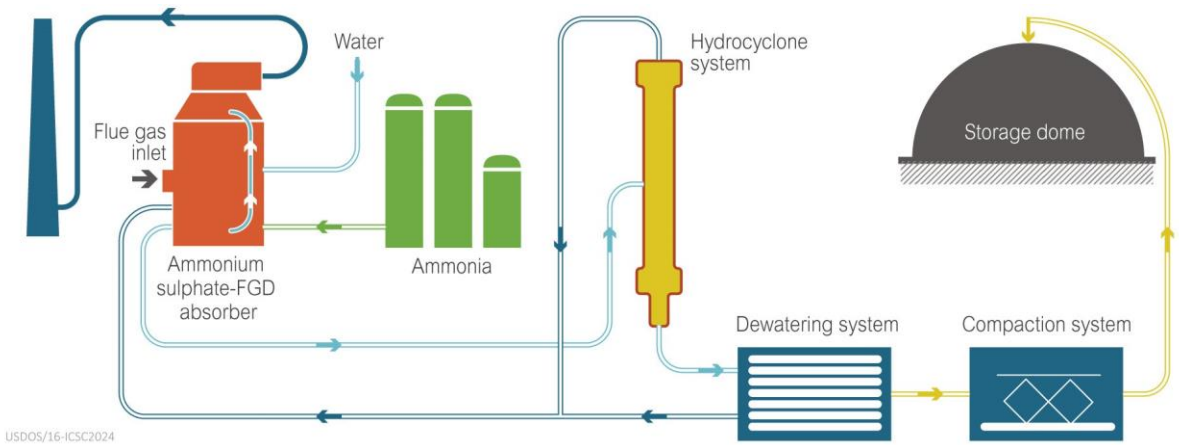

Figure 16 Schematics of ammonia-based wet FGD (Evans, 2012)

In wet FGD, factors such as the SO_2 inlet concentration and required outlet concentration, pH and stoichiometry, liquid-to-gas ratio, residence time and mist elimination are all crucial to SO_2 capture as they affect the design and operational performance. A higher liquid-to-gas ratio improves the SO_2 capture efficiency, but a higher inlet sulphur concentration will reduce the efficiency.

Wet FGD has over 90% efficiency. Some power plants may therefore have the option to choose only partial FGD installation to comply with emission norms. For many plants, partial FGD will help maintain the flue gas temperature, reduce moisture condensation in the chimney, and maintain the buoyancy of the flue gas for better dispersion. If a gas-to-gas heat exchanger is used, this will require additional space at the plant and will increase the cost. It may also lead to pressure drop and leakage but will help reduce inlet gas temperature, improving absorber safety and increasing treated flue gas characteristics for better buoyancy. With wet FGD, the flue gases are wet which requires additional lining of the stack, for example with 2 mm thick titanium (Grade 2 as per ASME SB265) or C-276 alloy over 8 mm thick (minimum) mild steel base or of C22 alloy or Borosilicate bock (CEA, 2019).

In seawater FGD, seawater is used as a low-cost scrubbing agent for SO_2 removal. If plants are in a coastal location, then seawater FGD requires low investment, low space and no chemical reagent handling while still providing high performance and availability. To remove SOx and other acidic components (HCl, HF), the flue gas is brought into intensive contact with seawater in the absorption zone to ensure mass transfer from the gaseous to the liquid phase. The seawater from the absorption zone is gassed with air before being returned to the sea to ensure oxidation of the separated SO_2 to sulphate.

A spraying tower is used to spray seawater evenly through nozzles at multiple levels against the flue gas flowing from bottom to top, as shown in Figure 17. At the outlet of the absorber, the clean gas is saturated and can be directly removed via a cooling tower or wet stack, or the clean gas can be heated and routed to a dry stack.

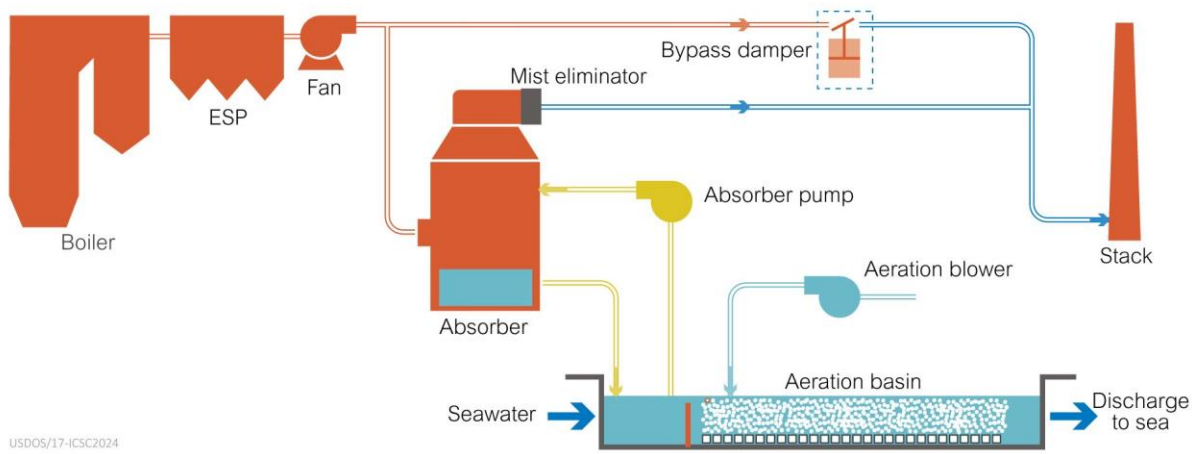

Figure 17 Schematics of seawater FGD (Mitsubishi Power, 2022)

The seawater from the absorption zone is mixed with fresh seawater from the power plant condenser to increase the pH value and is then conveyed to the final treatment system. To treat the seawater collected at the absorber bottom, aeration ensures the oxidation of separated SO_2 to sulphate and thus increases the pH value by stripping CO_2 from the water. Oxidation can take place in the sump of the absorber or in a downstream basin. Once treated, the seawater is returned to the sea.

In India, plants such as Tata Power Trombay (750 MW), Dahanu Thermal Power Station (500 MW), Udupi Thermal Power Station, (1200 MW), JSW Ratnagiri (1200 MW), NTPC Vindhyachal stage V (500 MW), and Adani Power Mundra Ph-III (1980 MW) operate seawater-based FGD (CSE, 2016).

Spray drying is a common dry FGD option and an effective method of producing dry powders from slurry by rapid drying with a hot gas. In this technology, the lime slurry is prepared in a lime slaker and passed to the absorber. The flue gas passes through an inlet pipe of the absorber and is sprayed with slurry (*see* Figure 18). The lime slurry droplets, which are atomised through rotary cup spray atomisers in a spray tower, absorb SO_2 from flue gas and neutralise it to form calcium sulphite ($CaSO_3$). Some of the $CaSO_3$ is oxidised to form $CaSO_4$ with the reaction of flue gas containing oxygen (O_2). Lime slurry is fed continuously to the absorber for lime replenishment.

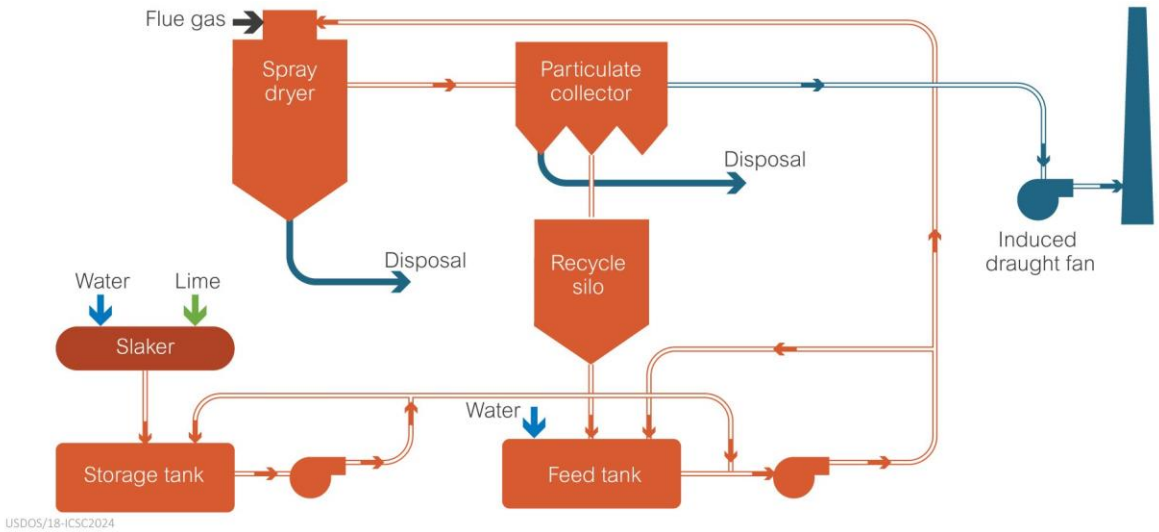

Figure 18 Schematics of a spray dryer absorber (Moss, 2010)

Compared to wet FGD, dry FGD systems have a lower Capex and Opex and lower overall power consumption. Dry FGD does not produce liquid waste, and the solid waste produced has suitable properties for landfilling and can be disposed with fly ash. However, the reagent utilisation efficiency of dry FGD is lower and it is more expensive than wet FGD to achieve the same SO_2 removal (He and others, 2017).

CFB dry scrubbers are considered a good alternative to spray dryer absorber technology, promising high SO_2 removal efficiencies, extremely low water consumption, and the ability to bridge the size gap between the wet and dry FGD options.

Unlike spray dryer absorbers, in CFB systems all reactants (SO_2, SO_3, lime, and water) are introduced at the bottom of the absorber vessel along with a large portion of particulate solids collected from downstream, as shown in Figure 19. Dry hydrated lime, $Ca(OH)_2$, is injected into the CFB absorber independently from the water and recirculated particulates. The flue gas is introduced beneath the sorbent bed and distributed across the vessel diameter. A mechanical water injection nozzle above the sorbent inlet sprays an atomized cloud of water droplets into the bed of solids fluidised by the incoming flue gas. The chemical reaction remains the same as for wet and dry FGD.

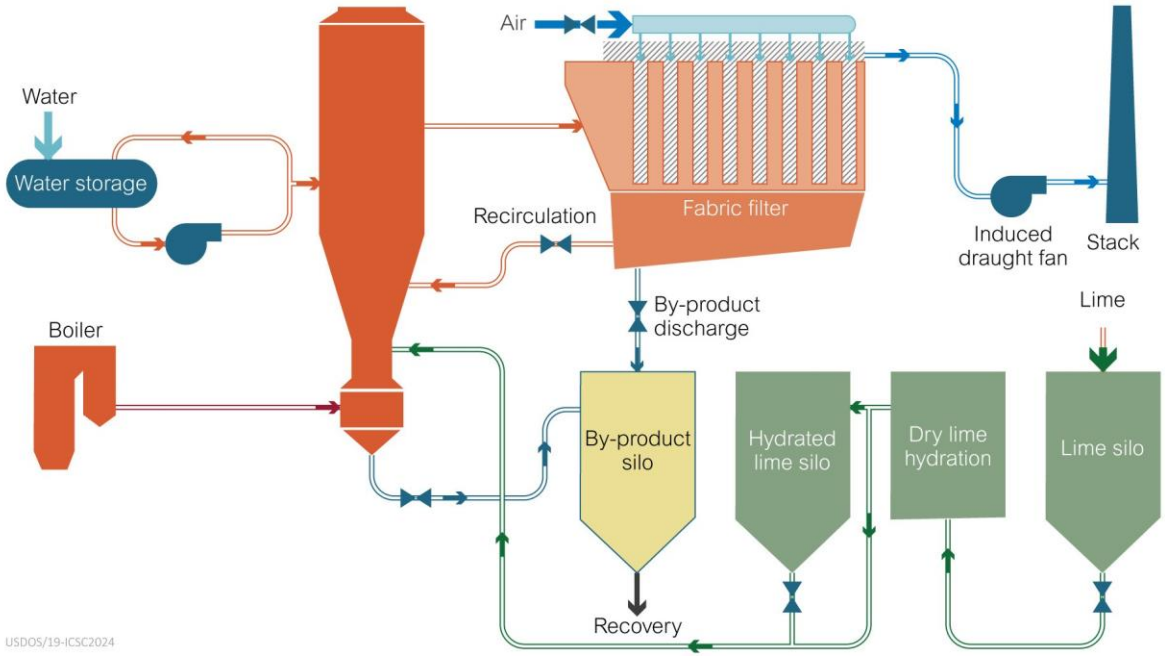

Figure 19 Schematics of a CFB dry scrubber FGD system (Moss, 2010)

CFB technology affords an enhanced heat transfer rate within the bed by spreading the water spray over a much larger surface area of solids. The ratio of solids to spray water is in the range of 20:1, translating into an approximately 20-fold increase in surface area as compared to a spray dry absorber (SDA). The flue gas entering the CFB absorber spends about five seconds passing through a fluidised bed and then adds more residence time passing through a tall and narrow CFB absorber vessel, resulting in improved SO_2 removal efficiencies within a small FGD system footprint. Because there are no high-speed rotary atomisers or lime slurry preparation equipment in a CFB system, the annual cost of replacement parts is much lower than in an SDA. CFB systems have been successfully installed at plants in China, Europe and the USA firing high-sulphur (up to 3.5%) coal. Demonstrated SO_2 removal efficiencies are in excess of 95% and can be as high as 99% (depending on inlet SO_2 loading).

CFB dry scrubber technology is installed on <10 MW to 350 MW size units, so multiple units are required for plants with a higher capacity. However, some manufacturers claim that a single absorber can be configured for 750 MW plants (Moss, 2010). CFB scrubbers have been installed on 660 MW coal-fired power plants in China (Jiang and others, 2011) and on 420 MW units at Dry Fork station in the USA (Carpenter, 2012, 2013).

Novel integrated desulphurisation (NID) is another emerging dry FGD technology offered by Alstom, (see Figure 20). A principal feature of this system is its J-reactor. The chemical process is the same as wet and dry type lime-based desulphurisation and so are the by-products. The stoichiometric ratio of lime-to-SO_2 is 1.5–1.8.

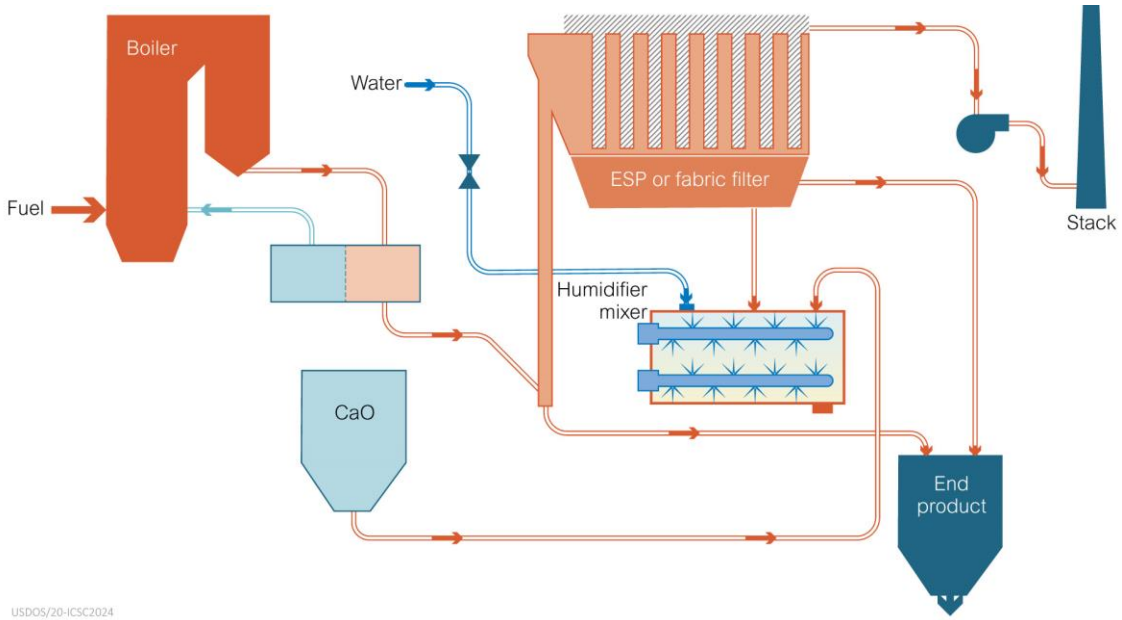

Figure 20 Schematics of NID (EPRI, 2007)

NID functions differently from a CFB as it is an entrainment process not a fluidised reactor. A key to its capability is the small cross-sectional area of the J-tube, where water for both lime hydration and flue gas cooling is introduced at the humidifier. Another unique feature of NID is its modular design, where an average reactor can handle the equivalent of approximately 75 MW of flue gas. Each NID module has its own reactor and ESP or baghouse. This is an advantage in construction and, notably, shipping. An important advantage of modular design is flexibility regarding unit turndown. Individual modules can be taken out of service until only one remains in operation. This final module can be turned down to 50% for extremely low-load operation. According to Alstom, the single capacity can be over 800 MW with multiple modular units. More than 60 NID systems have been installed worldwide including the Homer City Project (USA), NRG's Indian River Unit 4 (400 MW) and Dominion Brayton Point Plant Unit 3 (630 MW) (Carpenter, 2013).

DSI is an economical desulphurisation system which requires calcium or sodium-based alkaline reagents/sorbent injection during the combustion process within the furnace itself. The most common reagent used is hydrated lime [$Ca(OH)_2$], which reacts with SO_2 to produce calcium sulphate ($CaSO_4$) or gypsum. Instead of hydrated lime, other reagents such as trona (sodium sesquicarbonate, $Na_2CO_3{\cdot}NaHCO_3{\cdot}2H_2O$) or sodium bicarbonate ($NaHCO_3$) can also be used which react with SO_2 and generate sodium sulphate. The quantity of reagent required varies with the concentration of SO_2 in the flue gas, the purity of the reagent, and the control requirement.

The use of calcium-based reagents is more common for desulphurisation. Figure 21 shows a typical DSI flow system, highlighting the key parts: a storage and metering system; a conveying air system; a milling system (for sodium sorbents only); and a conveying piping/injection grid.

The hydrated lime stored in the silo is milled and carried to the flue gas stream using an ambient air stream. When using trona, which is hydroscopic in nature, dehumidification is required during unloading and conveying. Conditioning of the conveying air is common to reduce build-up and scaling in the metering and conveying components but is not always necessary if hydrated lime is used (ICAC, 2016).

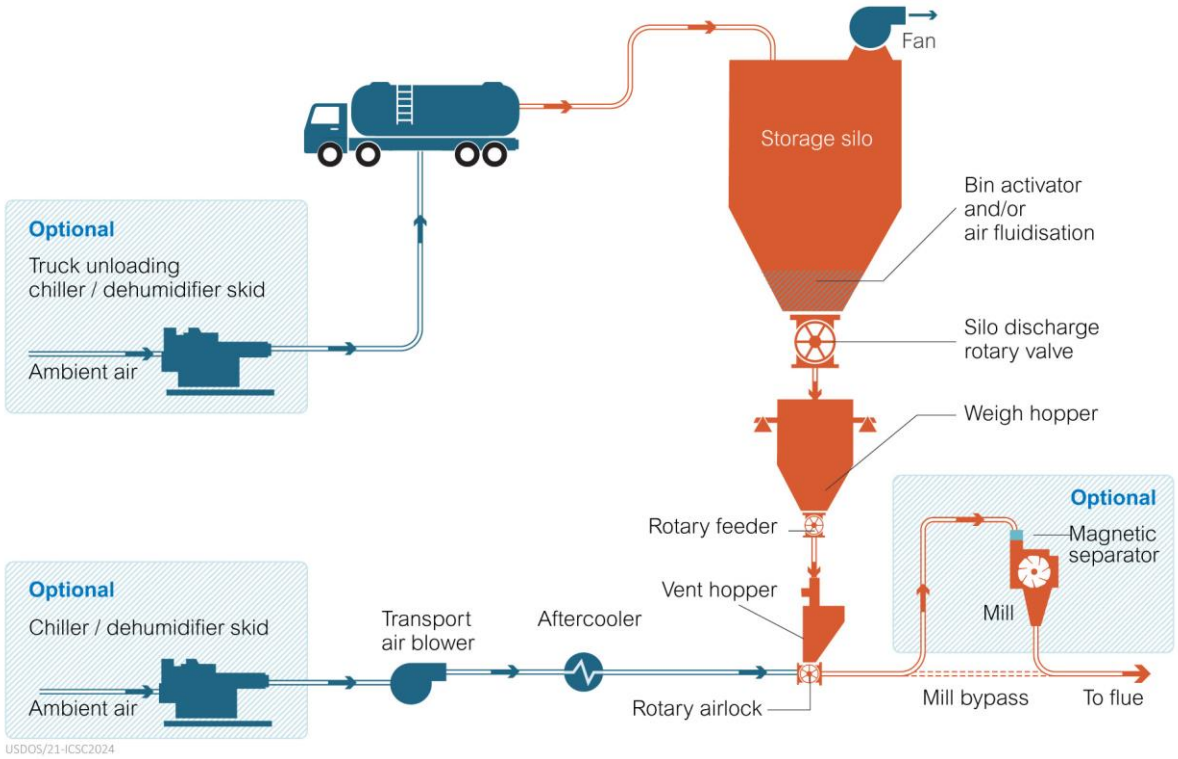

Figure 21 Schematics of DSI (ICAC, 2016)

The lime requirement can vary in the ratio of 1.3 mol Ca/mol of SO_2 and 1.8 mol Ca/mol SO_2 for 70% and 90% removal efficiency respectively. Based on this, a plant which must meet the norm of 600 mg/m^3 would require lime (90% pure CaO) at a rate of around 6 g/kWh on a gross generation basis. Similarly, with the use of a sodium-based reagent (sodium bicarbonate) around 1 mol Na_2 and 2 mol Na_2/mol of SO_2 will be required for 50% and 70% removal efficiency respectively. This implies around 12 g/kWh sodium bicarbonate consumption (100% purity) will be required to comply with the tighter 600 mg/m^3 norm. There are many lignite-fired CFBC boilers in India. These plants dose limestone in the furnace for SO_2 control. A typical CFBC can achieve 90–95% sulphur removal efficiency at a ratio of 2 mol calcium per mol sulphur and this can remove 200–300 mg/m^3 of the SO_2 in the flue gas. At this ratio, a CFBC boiler using 2650 kcal/kg lignite with 1% sulphur would require limestone at around 60 g/kWh (CEA,2019).

The use of DSI introduces new operational challenges for plants through the increase of dust load at the ESP or FF which will lead to more frequent cleaning. A change in the fly ash composition will mean that a new disposal path will need to be defined. An increase in fly ash resistivity will affect the dust capture efficiency in the ESP (sodium-based reagent reduces resistivity). If the power plant also uses halogen-based mercury control (*see* Section 5.4), the reagent used in the DSI system will neutralise the halogen and therefore affect mercury oxidation and control (ICAC, 2016). A DSI retrofit (with a gas-to-gas heater) also increases the auxiliary consumption by around 0.3% of the gross generation of the plant (CEA,2019).

CEA (2019, 2020) suggestions for optimum selection of SO_2 control technology in Indian power plants

The construction of an FGD unit involves both civil and mechanical work, including the installation of scrubbers, gas re-heaters, ducting and chimney lining, or the construction of a new chimney. Typically, construction takes about 18 months for a 500 MW unit. The shutdown time to install a wet FGD system takes up to one month, depending on the chimney construction. It is, therefore, important to take into account the techno-economic issues of the plant to determine the most appropriate technology to control SOx. This would include the unit size or technology, the age or remaining life of the plant, the operating performance and cost of generation, relevant emissions and the applicable standards required to reduce them.

- Plants older than 25 years should not be required to install FGD units. They should explore reducing SOx emissions through sorbent injection or obtaining low-sulphur fuel.
- Smaller (<500 MW) units may need to consider the option of partial FGD – treating a lower volume of flue gas. This process would cost less, in the range of 0.3 cr/MW (36,193 $/MW), and its installation would suffice to meet the 600 mg/m^3 norms. The retrofit costs are approximately 0.25–0.3 cr/MW (30,160–36,193 $/MW).
- DSI is preferable for smaller TPP (60–250 MW), those running on a low PLF and with shorter remaining operating life (7–9 years). The adaptation of this technology may be finalised based on techno-economic feasibility considering the PLF of the unit, the required efficiency of the FGD system, the balance of operating life and the Opex (reagent consumption cost).
- Larger (>500 MW) units were required by environment clearances to allocate spare land for possible installation of an FGD unit in future. To meet an SO_2 standard of 200 mg/m^3, these units will need to install dry or wet FGD units. The retrofit costs are approximately 0.5 cr/MW (60,321 $/MW).
- Limestone technology has a large footprint, and higher Capex and reagent purity issues than ammonia-based and dry FGD technologies. Ammonia-based FGD technologies are preferable for unit sizes below 500 MW where they have approximately 10% less Capex and air pollution control compared to limestone-based FGD. The availability of ammonia and additional safety requirements for the handling of this new material must be considered. However, there is the added advantage of a readily saleable by-product – ammonium sulphate. Power plants must conduct a 'life cycle cost benefit analysis' when choosing the available FGD technologies.

The stack height formula for plants with wet FGD was revised in the June 2015 notification from the MOEFCC (CPCB, 2015), as below:

- for 100 MW and above units: H=6.902 (QX0.277)0.555 or, 100 m (minimum)
- for less than 100 MW units: H=6.902 (QX0.277)0.555 or, 30 m (whichever is more)
- where, H= height in m, Q= is SO_2 emission rate in kg/h

This may reduce the cost of larger stacks in new plants and the cost of the stack inner lining needed for wet FGD.

The regenerative activated coke technology (ReACT™) system is marketed by J-Power Entech (Japan) and is installed in many plants including the Isogo power plant (2 x 600 MW units, Japan), Takehara power plant (350MW unit, Japan), Weston plant (USA) and many plants in Germany. Over 99% of the SO_2 and SO_3, 20–80% of the NOx, over 90% of the mercury (both elemental and oxidised), and around 50% of the particulates are removed in the process when burning low to medium sulphur coals (Carpenter, 2012). The ReACT™ system is installed after the particulate control device and acts as a polishing stage for particulates.

The process involves three stages: adsorption, regeneration, and by-product recovery (*see* Figure 22). In the adsorption stage, ammonia is injected into the flue gas which then passes horizontally through the absorber (a single- or two-stage tower) containing a moving bed of coal-derived activated coke. The activated coke flows slowly downwards through a series of modules installed side by side. SO_2, SO_3, NOx and mercury are removed through adsorption, chemisorption, and catalytic reactions. SO_2 reacts with oxygen and water vapour in the flue gas (through catalytic oxidation) to form sulphuric acid, which is adsorbed on the activated coke. It also reacts with ammonia to form ammonium sulphate and bisulphate. SO_3 reacts with water vapour, also forming sulphuric acid. NOx is catalytically reduced on the activated coke surface, reacting with ammonia to form nitrogen and water. Mercury is retained on the activated coke. Particulates are removed by their impact on the coke pellets. The clean flue gas exits the adsorber and is released through the stack. The activated coke takes around 80–120 hours to pass through the adsorber and the residence time for the flue gas is around 10 seconds.

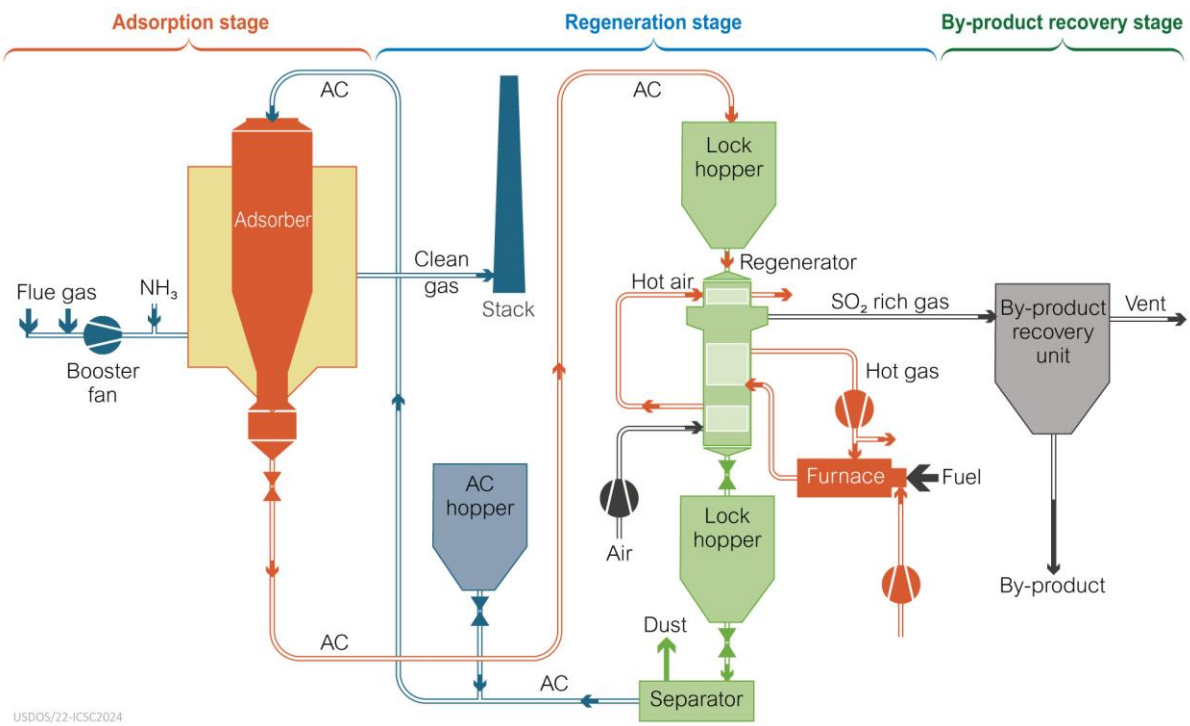

Figure 22 Schematics of ReACT (Carpenter, 2013)

The ReACT™ system is a dry process (requiring no water for humidification or flue-gas saturation), easy to install in limited space, easy to maintain and consumes around 0.7% of the plant's gross output. Since the SO_2 adsorption in ReACT™ improves with lower flue gas temperature, SO_2 compliance is easier at lower temperatures and during turndown. Conversely, NOx emissions will be higher during start-up due to the time it takes the absorber to reach the operating temperature required for denitrification (Carpenter, 2013).

Isogo Power plant burns low sulphur coal and has used the ReACT™ system as a flue gas polishing technique since 2002. It has over 98% SO_2 removal, reducing flue gas concentrations from 200 - 400 ppm at the inlet to 5 ppm at the outlet. ReACT™ technology also provides 20–40% NOx removal. Co-benefit emission control is extended to mercury, achieving over 90% reduction (Sloss, 2017). Saleable by-products such as sulphuric acid, pre-collected fly ash and spent activated coke from the mercury capture zone (14 t/y from a 250 MW unit) can be sold. Operating costs include the replacement of activated coke which, for a 250 MW plant, is around 135 t/y. No solid or liquid wastes are produced since the fines separated from the regenerated activated coke can be burnt as a fuel or sold and used in industrial applications, such as carbon sorbents.

Unlike wet FGD processes, ReACT™, with its low SO_2, NOx and PM emissions and the avoidance of water addition to the flue gas stream, may help to optimise CO_2 reagent life, if a post-combustion CO_2 control system is installed.

5.3 NOx EMISSION CONTROL

In a coal-fired power plant, NOx is formed during coal combustion both from nitrogen present in the coal and from the nitrogen in the combustion air. NOx may comprise N_2, NO_2, NO, and/or N_2O depending on the combustion chemistry within the boiler. In general, 90–95% of NOx emitted from coal power plants is in the form of nitric oxide (NO) (CSE, 2018).

There are two main types of NOx control:

- primary measures which can be implemented within and around the combustion zone, such as low NOx burners (LNB), overfire air (OFA) and combustion optimisation, and
- secondary measures which can be applied downstream, including selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technology.

Most controls can be applied alone or in combination, as shown in Figure 23, depending on the rate of NOx removal required (Wiatros-Motyka and Nalbandian-Sugden, 2018).

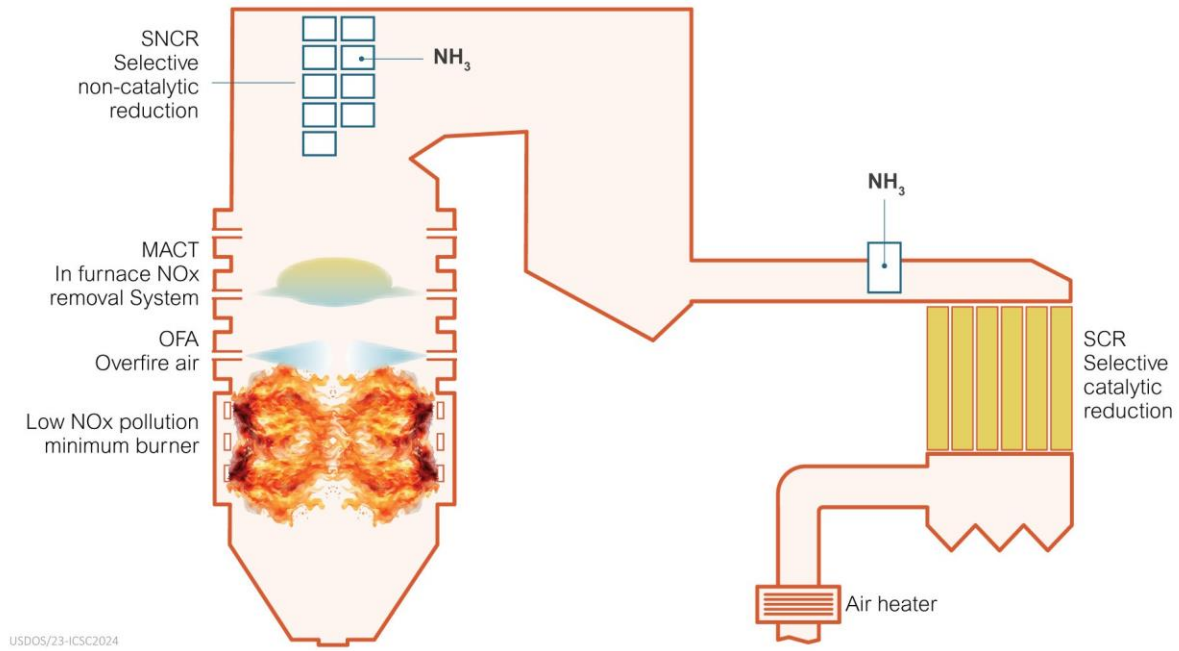

Figure 23 Schematics of a typical coal-fired plant with various DeNOx installations (MHPS, 2019)

Although the choice of appropriate NOx controls depends on several factors, the required level of NOx reduction is the most critical. To meet stringent NOx emission regulations, it has been standard practice to start with primary measures such as LNB and OFA and then add an SCR, SNCR or a combination of both. For new units, primary and secondary NOx controls are installed in combination during construction. Figure 24 shows NOx level reductions with different technologies in relation to the evolving European environmental regulations (Adams and others, 2021).

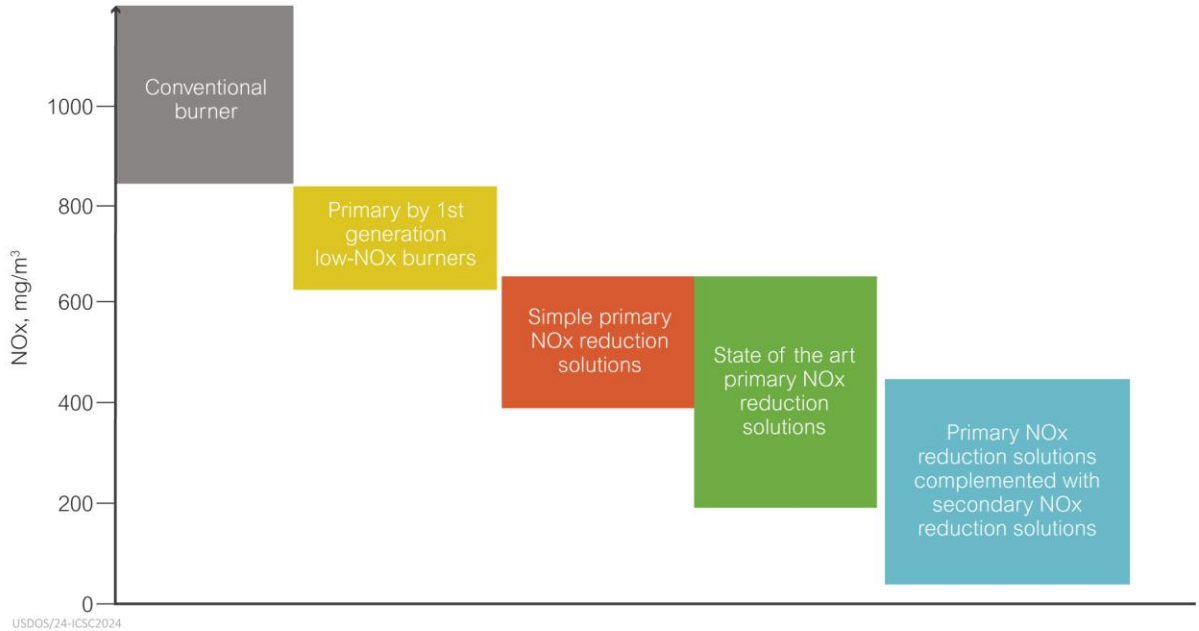

Figure 24 NOx reduction levels with various control technologies in the EU (Adams and others, 2021)

As shown in Figure 24, the latest primary measures on their own can lower NOx emissions to around 200 mg/m^3. Most Indian plants comprise large-sized boilers firing using lower-quality coal so a higher NOx level of 300 mg/m^3 has been reported using only primary measures. Currently, some Indian plants will not require secondary measures for NOx control. However, since these secondary pollution control technologies can also extend co-benefits to other pollutants, it is important to consider a comprehensive plan and cost-benefit analysis for the selection of emission control technologies to address multiple pollutants. Guizhou Fa'er power plant and Hunchun power plant (China), commissioned in 2013 with a combination of primary and secondary control measures, have achieved NOx emissions of around 88 mg/m^3 (Adams and others, 2021).

5.3.1 Primary NOx control measures

The level of NOx reduction achieved by primary measures depends on several factors such as coal properties (particularly nitrogen content and fuel ratio), coal fineness, air-to-fuel ratio and distribution to each burner, all air flows (primary, secondary, tertiary), burner level and mills in use, boiler load, boiler dimensions and geometry and bulk furnace temperature. When selecting a NOx reduction strategy, all these factors should be considered and modelling may be required for the selection process (Sloss and others, 2023a).

Combustion optimisation is the primary initiative which helps reduce any emissions through reducing coal combustion and increasing plant efficiency. It can have many forms, including ensuring optimal mill performance and coal fineness, adjusting air-to-fuel ratio, trimming excess oxygen in the furnace, and fine-tuning combustion controls. The NOx reduction potential is around 15–35% and is dependent on fuel type, boiler dimensions, existing burners, OFA technology and existing coal mill performance (CSE, 2018).

The air-to-fuel ratio of a boiler is key to optimum combustion and affects combustion parameters such as boiler efficiency; oxygen and CO level; loss on ignition (LOI) or carbon in ash (CIA); and furnace exit gas temperature (FEGT), as shown in Figure 25. NOx emissions can be reduced by careful control of the air-to-fuel ratio by several commercially available technologies. Such systems monitor and regulate all combustion air streams and the air-to-coal ratio while ensuring even fuel flow distribution between individual burners.

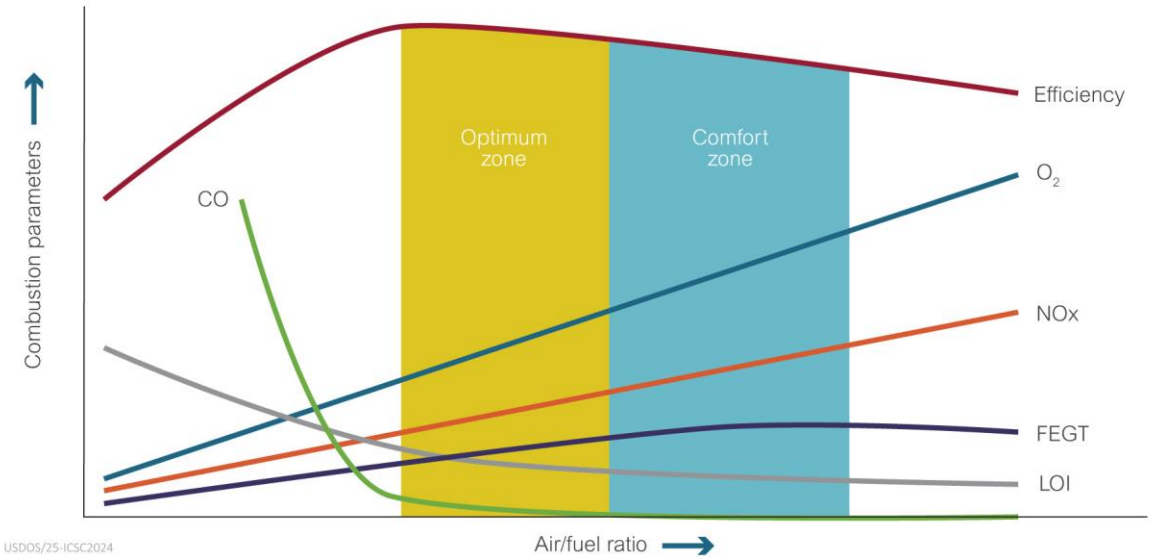

Figure 25 Combustion parameters versus air-to-fuel ratio (Adams and others, 2021)

Maintaining the correct air-to-fuel ratio can increase plant efficiency by up to 1–2% and lower NOx emissions by up to 10%. The effect of increasing plant efficiency is significant – it provides more power for less coal, lowering costs and emissions simultaneously. New digital instruments can cost up to €1 million (INR 8.9 crores; $1.08 million), for both coal and air monitoring and control, but the saving on coal combusted means that the payback time is often less than one year (Sloss and other, 2023a).

LNB are the most common technology used worldwide. They are easy to install, although the designs of LNB vary widely between manufacturers. All LNB work on the principle of staging combustion air within the burner to lower the peak flame temperatures and reduce NOx formation (Wiatros-Motyka and Nalbandian-Sugden, 2018; *see* Figure 26). LNB optimise combustion to create a large and balanced flame; the peak flame temperature is controlled through the oxygen supply to the fuel-rich environment and hence a minimal amount of NOx is produced. As the temperature is reduced, hydrocarbons react with the NOx and create a reducing atmosphere. A minimal amount of NOx is produced in the last stage when the internal air staging finishes (Ruichang, 2019).

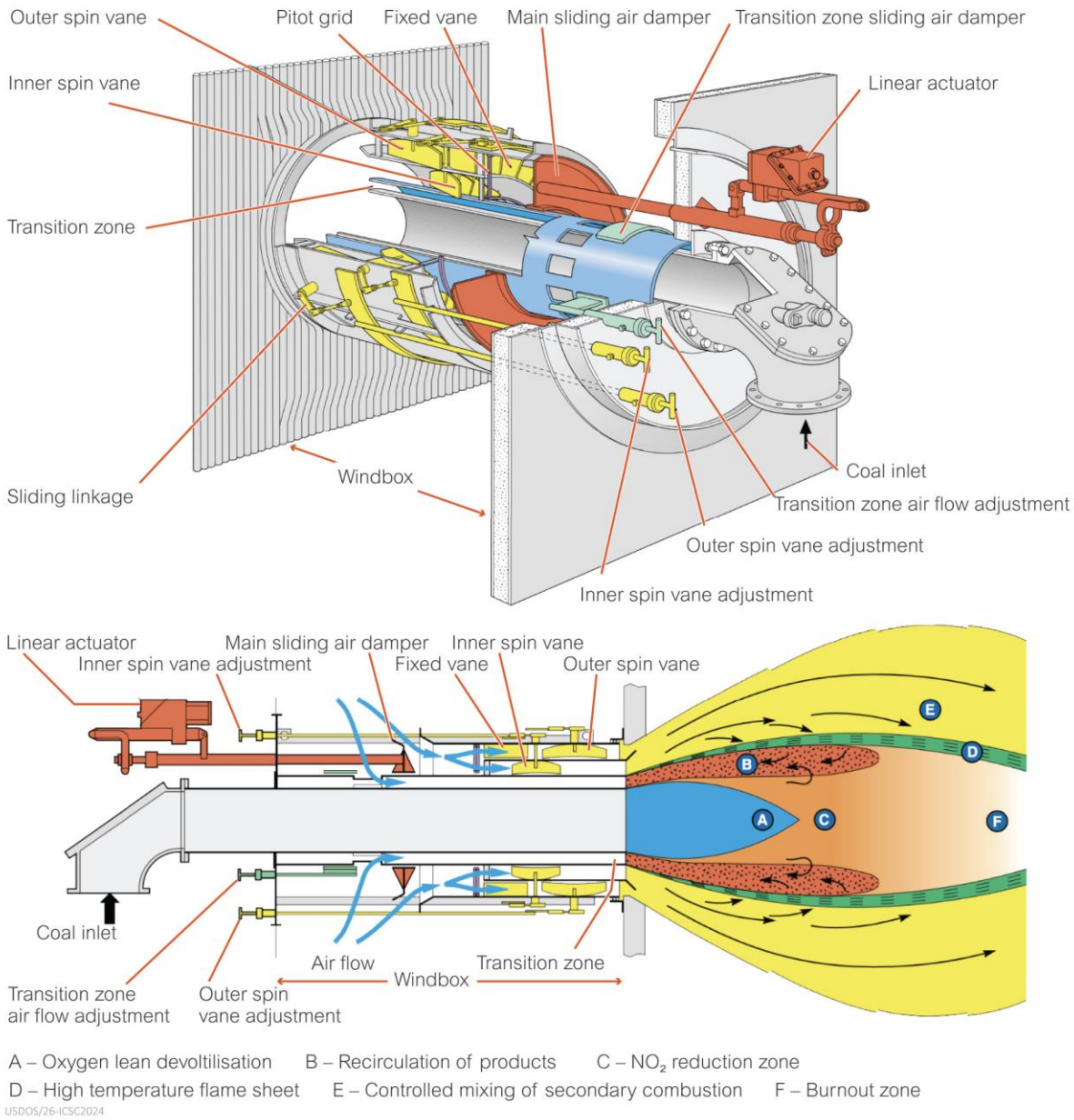

Figure 26 Schematics of an LNB (Babcock and Wilcox, 2020)

Different LNB designs use several techniques for NOx control including different fuel/air mixing designs, changes in internal dimensions, pressure drop requirements, flame geometries and control requirements. All the designs aim to configure an optimum combustion process where the flame is stabilised, using internal air and fuel staging to manage fuel-rich and fuel-lean areas of primary combustion. These designs must be reviewed and vetted when selecting and installing new burners, including the consideration of multiple strategies used together. For example, LNB can be combined with other primary measures such as OFA reburning or flue gas recirculation (Berry, 2017). Typically, LNB can reduce NOx by 30–50% on their own, but in combination with separated OFA (SOFA, *see* below) and some combustion optimisation, they can reduce NOx by up to 70% (Adams and others, 2021).

LNB are a common choice because they are cost effective in terms of both Capex and Opex, they require no additional space, and installation is not time consuming. If LNB and SCR are used in combination, then a smaller and more cost-effective SCR may be adequate. However, when choosing a low NOx burner design for a specific boiler, the following considerations must be addressed (Berry, 2017):

- Most LNB need high air-side pressure drops for air-to-fuel staging which may lead to draught loss. The capacity of existing forced draught (FD) fans may need to be assessed.
- Many LNB include a flue gas recirculation system which may need up to 5–30% additional boiler flue-gas flow and pressure drop. Therefore, the capacity of the existing FD and ID fan should be assessed. Additional mass flow may also impact the boiler superheat temperature and therefore superheater modifications may also be required.
- Since LNB also change the air-to-fuel ratio, their effect on the functioning of rear- or side-wall burners should also be assessed.
- Retrofitting LNB while using the existing burner wind box may face issues with space availability and may require platform modification, dismantling and reinstallation of the wind box and related mounted equipment.
- NOx emission reduction may require the removal of air-preheating in the boiler. This has implications with respect to boiler efficiency and may also affect mass airflow in the boiler and thus the pressure drop.
- LNB may require larger pipe diameters to facilitate fuel/air staging. The extent of this must be assessed to ensure it does not cause issues at the interface with furnace waterwall openings.
- Some LNB designs require specific fuel supply and/or control requirements, multiple control valves, flame scanners, reduced boiler ramp rates, special fuel/air ratio curves and fuel and airflow measurements. This may mean that modifications will be required in existing fuel trains, the burner management system (BMS), and the combustion control system (CCS).

OFA systems control the availability of oxygen near the burner area, minimising the formation of fuel NOx. About 70–90% of the required total combustion air is provided near the burners, creating an oxygen-deficient, fuel-rich zone, leading to partial combustion of fuel. The balance of the combustion air is then injected above the burner elevation, through the OFA nozzles into the furnace, where combustion is completed.

In two-stage combustion, the airflow to the burner is first mixed with the fuel at the burner, producing an oxygen-deficient, fuel-rich zone and resulting in minimised formation of fuel NOx and partial combustion of the fuel. During the second stage, the balance of the combustion air is injected through the OFA nozzles into the furnace, where combustion is completed (Xu and others, 2015). Two-stage combustion in combination with an overall lower level of excess oxygen reduces the net unit heat rate as well as SO_3, CO and LOI, and produces a more uniform temperature profile at the furnace exit.

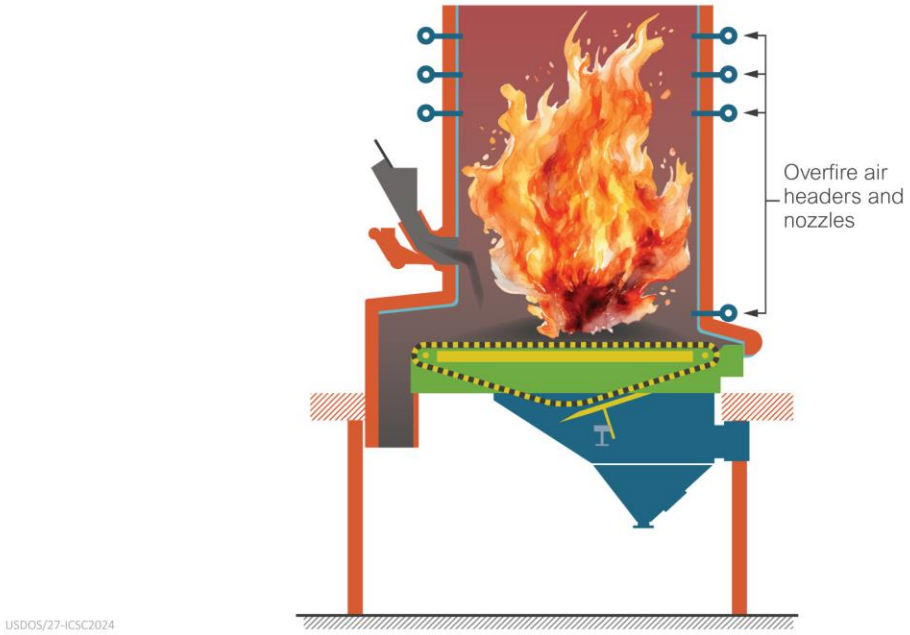

Figure 27 A typical OFA system (Detroit Stoker, 2022)

There are numerous commercial OFA systems which can reduce NOx formation by 20–45% (CSE, 2020a). OFA is frequently used in combination with LNB and/or flue gas recirculation and also with post-combustion DeNOx systems for better NOx control.

The location of the injection ports and mixing of the OFA are critical to maintaining efficient combustion. However, although most existing boilers in India already have OFA systems, these are usually the closely coupled type which means that there is insufficient distance between the burners and the overfire air. The coal particles do not have enough time to burn out effectively and the potential benefits of such systems are limited, especially in comparison with those systems which are placed at a sufficient distance from the burners. These latter systems are called separated overfire air (SOFA). There are several SOFA system designs with variable numbers of stages. Each stage can have 1 to 4 compartments with one OFA nozzle. The number of SOFA compartments and stages needed depends on the NOx emission reduction required and is always determined on a plant-by-plant basis, using computational fluid dynamics (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. 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 and tangential) (Sloss and others, 2023a).

SOFA has been installed at an Indian coal plant, CLP Jhajjar, Haryana, where NOx emissions were reduced to below 300 mg/m^3 at two units. GE has carried out SOFA installation at 19 NTPC units totalling almost 10 GW. An emission target of 400 mg/m^3 was requested by NTPC but greater reductions would have been possible if a further SOFA layer had been installed (Adams and others, 2021).

5.3.2 Secondary NOx control measures

Secondary NOx control involves post-combustion measures. The NOx generated in the combustion zone moves with flue gas, which needs to be treated with secondary control measures to bring down NOx concentration to the minimum for compliance. SCR and SNCR are the two most popular and proven secondary NOx control technologies. These systems lower NOx emissions by neutralising them into nitrogen gas via chemical reactions either with or without a catalyst.

SCR is the most effective and well-established NOx removal technology and has been in use since the early 1970s. It can be applied as a standalone control technology or in combination with other technologies, including SNCR, combustion optimisation and in-combustion modifications such as LNB and OFA.

An SCR system, shown in Figure 28, broadly comprises ammonia storage, a vaporiser and injection grid system, and a catalyst-based reactor. A catalyst is usually made of vanadium pentoxide (V_2O_5) or tungsten trioxide (WO_3) supported on titanium dioxide (TiO_2). NO is reduced by NH_3, which is injected upstream of the SCR catalyst bed, at temperatures above 300°C. The V_2O_5 sites adsorb the ammonia strongly, while NO reacts from the gas phase or, as a weakly adsorbed species (Eley-Rideal mechanism). Both NO_2 and NO are decomposed into N_2 and H_2O vapour. The SCR catalyst efficiently facilitates ammonia and NOx reactions (Monterroso and others, 2011).

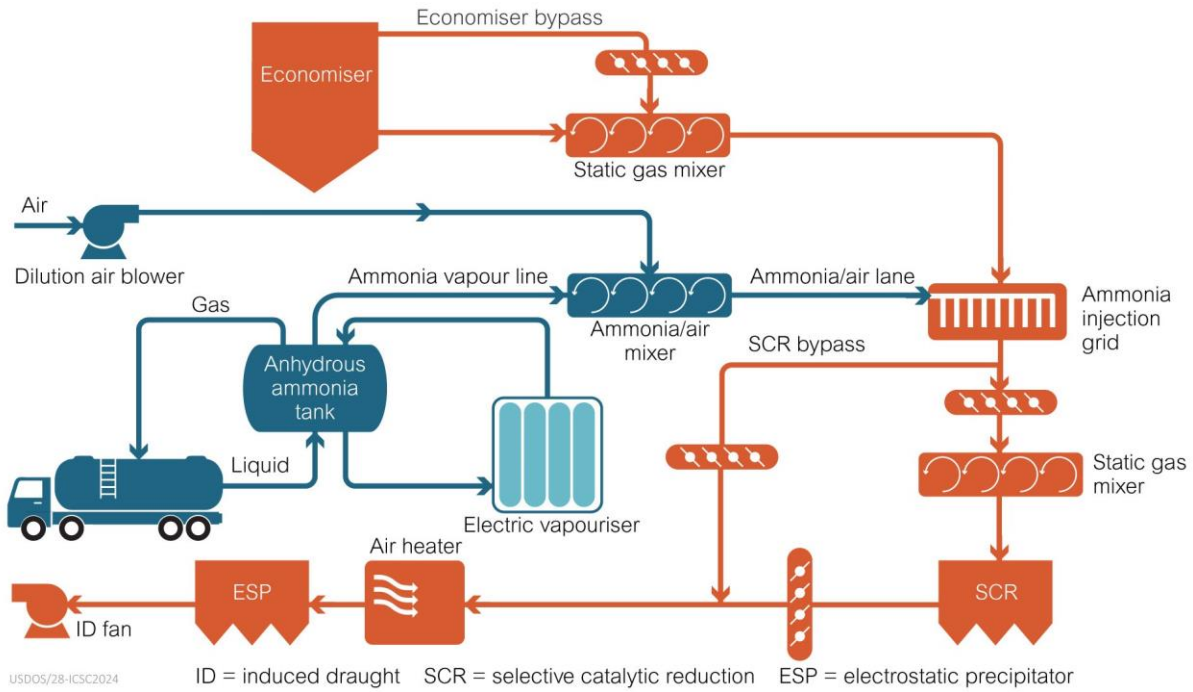

Figure 28 Schematic of a typical SCR system (Sorrels, 2019)

The technology can be arranged in three different layouts in a coal-fired power plant (Wiatros-Motyka and Nalbandian-Sugden, 2018):

- high-dust (before the PM control system);
- low-dust; and
- tail-end position.

The layouts are shown in Figure 29.

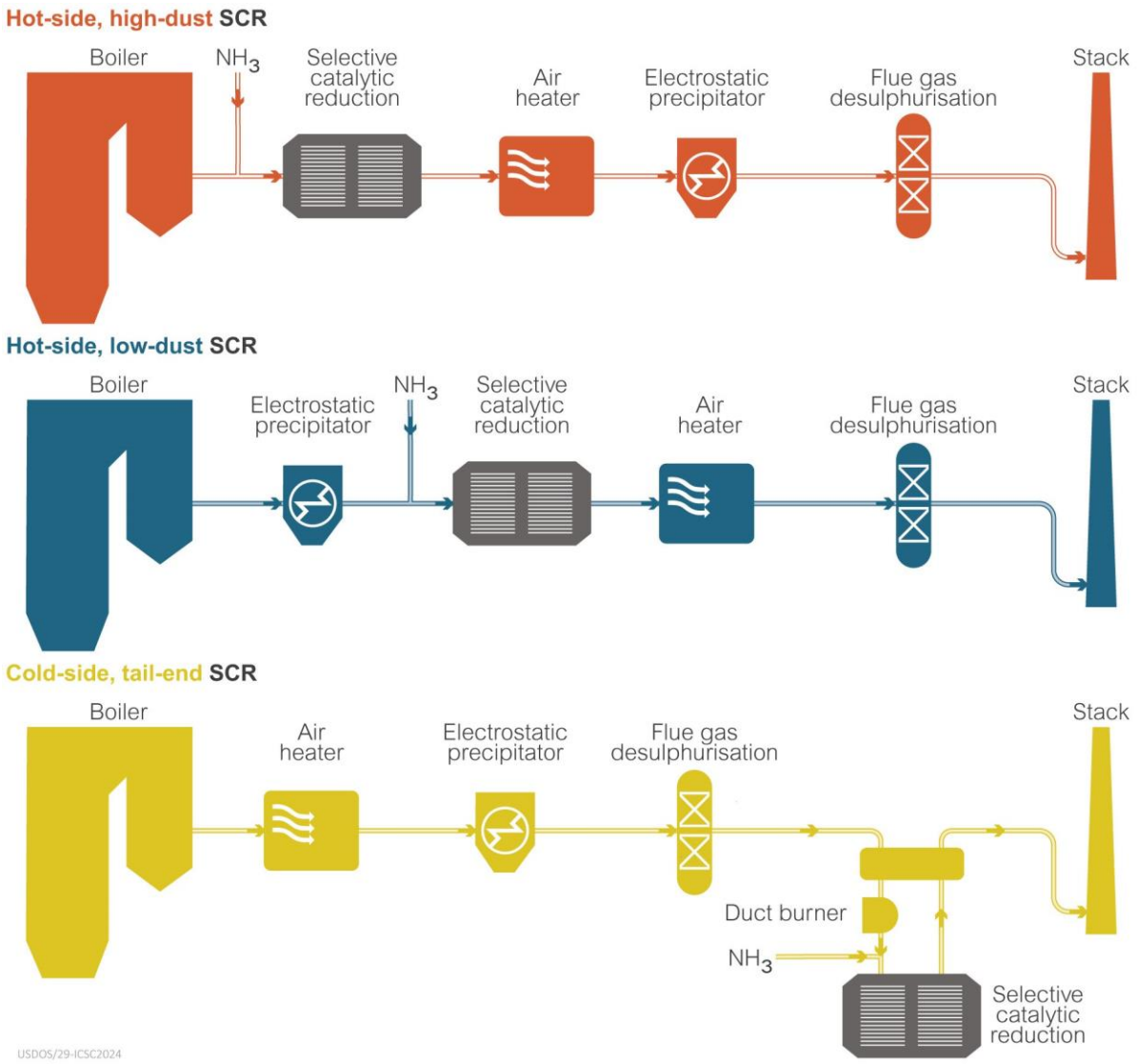

Figure 29 Different SCR positions in a typical coal-fired plant (Wiatros-Motyka and Nalbandian-Sugden, 2018)

Hot-side, high dust SCR is the most widely used configuration in coal-fired power plants internationally. An SCR is installed upstream of the PM control, between the economiser and the air heater, where the temperature of the flue gas (300–400°C) is ideal for the SCR reaction. However, in this configuration, the catalyst is exposed to poisoning by the fly ash and chemical components of the flue gas, such as sulphur trioxide (SO_3). For Indian power plants, high ash content makes hot-side CSR an unsuitable choice. An alternative is hot-side, low-dust SCR, installed downstream of the ESP/FF where the catalyst faces low dust. However, some plants may need to install a costly hot-side ESP, or

modify the existing one with a flue gas heating system, to maintain the optimal temperature required for the catalytic reaction of NOx. Cold-side, tail-end SCR, (also called cold-side, low-dust SCR) is installed downstream of the FGD. It is also a more costly option due to the requirement of an additional flue gas heating and heat recovery system but this can be compensated for by a lower Opex for the catalyst.

Cold-side, tail-end SCR is suitable for Indian units. SCR has a high proven efficiency of over 90%. The cost of SCR may be around INR 20 Lakh/MW ($24,129/MW) with a catalyst replacement expenditure of INR 2.5–2.7 Lakh/MW (3016–3257 $/MW) every three years (CSE, 2016). To date, there is information of any commissioned and operating SCR in any Indian power plants. Reports, however, indicate that some of the plants such as Harduganj TPP, Obra TPP, Jawaharpur TPP and Panki TPP of Uttar Pradesh Rajya Vidyut Utpadan Nigam Limited (UPRUVNL) had issued the Tender with scope of SCR for its 660MW size units (UPRUVNL, 2020). Bharat Heavy Electricals Limited (BHEL) reports that it has started manufacturing SCR indigenously to fulfil the orders from Yadadri TPP (800MW), Bhuswal TPP (660 MW), Sagardighi TPP (660 MW), Damanjodi TPP (18.5 MW) (BHEL, 2023).

SNCR is another NOx control technology which relies on the post-combustion injection of reagent using a catalyst, as shown in Figure 30. The injection is into the furnace above the combustion zone at locations where the flue gas temperature ranges from 900°C to 1100°C. Ammonia and urea are the most common reagents, although other chemicals such as amines, amides, and cyanuric acids have also been tested. The temperature window plays a critical role in the effective operation of the SNCR system. Since anhydrous ammonia is highly toxic and requires strict handling, alternatives such as dry urea, molten urea, and urea solutions are preferred (Miller, 2017).

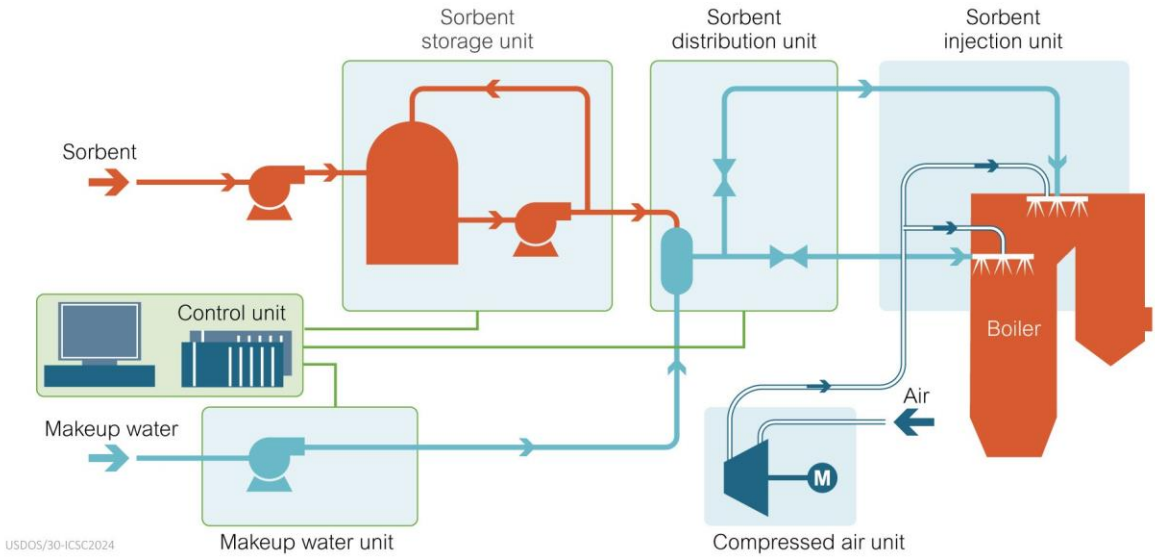

Figure 30 Schematic of SNCR (Jet Inc, 2023)

On average, SNCR can reduce NOx by 30–50% on its own, but when used in combination with primary measures the reduction rates can be as high as 70% (Wiatros-Motyka and Sugden, 2018; IFS, 2021).

The efficiency of SNCR depends largely on where the reagent is injected. The optimum window relies on carbon monoxide, oxygen, and temperature, which change with the plant load. Therefore, these key combustion parameters must be monitored and subsequent adjustments made to the injection location to ensure that the reagent is injected in the right temperature window, typically between 900 and 1150°C (Adams and others, 2021). If these conditions are not maintained the effectiveness of the system is lower and several problems can occur. For example, if the temperature is too high, the ammonia will produce additional NOx. Alternatively, if the temperature is too low, the NOx reduction reaction will not occur, and the ammonia will remain as ammonia slip and be wasted. Additionally, ammonia slip can react with SO_3 present in the flue gas to form ammonium sulphate and ammonium bisulphate. Ammonium bisulphate tends to condense on the cooler surfaces of the air heater and can cause significant loss of efficiency, in addition to mechanical damage (Xu and others, 2015). Therefore, effective operation of the system at various load regimes requires close temperature monitoring within the furnace and reagent injection in areas to maintain the appropriate temperature window (Sloss and others, 2023a). The use of multiple zones of injection and the ability to take injectors in and out of service as needed allows for chemical release within the desired chemical and thermal environment. This approach provides good opportunities for effective NOx and ammonia slip control and has been commercially proven even on units as large as 660 MW (Sloss and others, 2023a).

In practice, SNCR is always used in combination with primary NOx controls and can also be combined with SCR. SNCR can be fitted on new plants as well as retrofitted on existing ones and the industry has significant experience in such installation, including in high ash coal boilers such as those in India. SNCR has considerable advantages over SCR, it is economical, both in terms of Capex and Opex, it has small plot requirement and is simple to install and retrofit. However, SNCR has a lower efficiency, requires a narrow temperature range for operation, requires more water for proper reagent spray and retrofitting can be challenging.

SNOX™ is a dry catalytic process developed by Haldor Topsoe for SOx and NOx emissions control (see Figure 31). This technology is installed in many power plants including the 300 MW Nordjyllandsværket power plant (Denmark), a pet coke-fired power plant in Italy, and a heavy residual fuel oil power plant in Austria (Carpenter, 2013). The SNOX™ unit is located downstream of the ESP/FF. The dedusted flue gas is reheated in a heat exchanger to around 400°C and ammonia is injected before the gas enters the NOx reduction reactor. NOx is reduced by the ammonia over a proprietary catalyst to nitrogen and water, just as in conventional SCR operation. The flue gas is then heated and SO_2 is catalytically oxidised to SO_3 in a second reactor. Designs where the two catalytic reactors are integrated into a single unit are also employed. The flue gas exiting the oxidation reactor passes through the hot side of the heat exchanger where it is cooled as the incoming flue gas is heated. SO_3 reacts with water in the flue gas to form sulphuric acid vapour, which is then condensed into 94–95% concentrated sulphuric acid in the WSA (wet gas sulphuric acid) condenser. Boiler

modifications will be necessary for SNOX™ retrofits to enable full integration of the heat recovery features, particularly for the use of preheated air (WSA cooling air) as boiler combustion air.

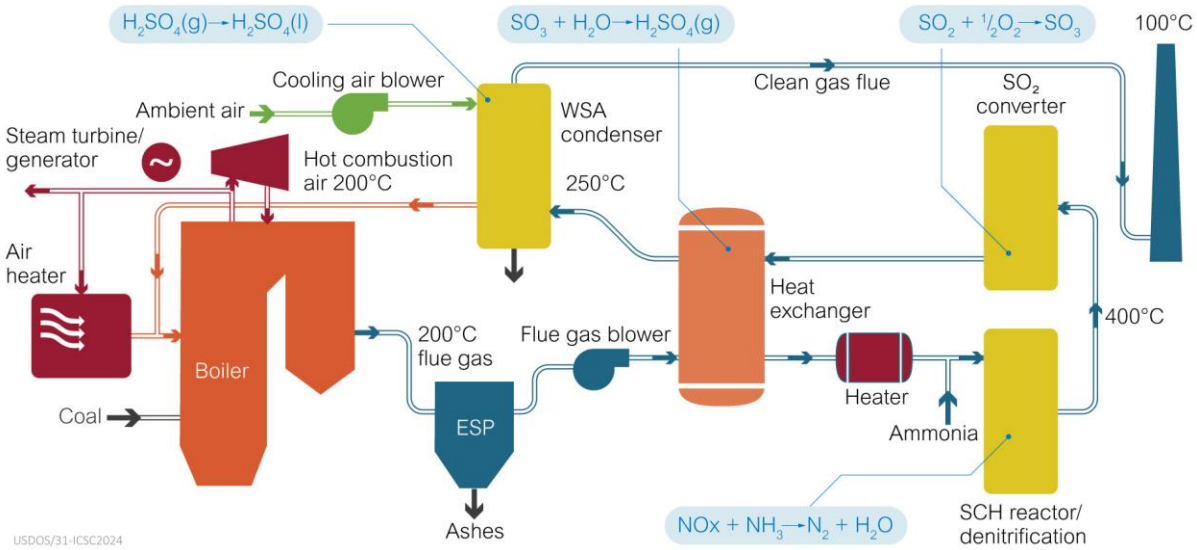

Figure 31 Schematics of the SNOX™ process (Carpenter, 2013)

Similar to SCR, the process requires the flue gas to be cleaned to protect the catalyst. The surplus ammonia is used in the SCR reactor to achieve a high NOx reduction efficiency without problems with ammonia slip, as all the ammonia in the gas after the SCR reactor is oxidised in the SO_2 oxidation reactor to nitrogen and water vapour. No wastewater and waste are produced, besides a saleable by-product sulphuric acid (2.2 kg H_2SO_4 is produced per kg of SO_2 emissions). The operating cost of a SNOX™ unit decreases with increasing SOx content in the flue gas due to heat recovery – in a 500 MW coal-fired power plant, the heat recovery is more than the supplemental power (12.5 MWe) needed for the SNOX™ plant and could provide a potential net gain equivalent to 8 MWe. SNOX™ has lower capital requirements and lower operation and maintenance costs than a wet limestone FGD + SCR plant burning high sulphur (2.9% S) coals. However, SNOX™ requires more space than a typical wet FGD or SCR unit (Carpenter, 2013).

5.4 MERCURY CONTROL

Coal combustion is the single largest source of mercury emissions, contributing nearly 80% of total emissions in India (CSE, 2020a). Mercury contents in Indian coals are typically in the range of 0.003–0.34 g/t with an average concentration of 0.14 g/t (UNEP, 2018). However, due to the large volume of coal burnt, a significant amount of mercury is released into the atmosphere. During combustion, the mercury in coal is volatilised and converted to elemental mercury (Hg^0) vapour in the high-temperature regions of coal-fired boilers. As the flue gas is cooled, a series of complex reactions begin to convert Hg^0 to ionic mercury (Hg^{2+}) compounds and/or to mercury compounds that are in a solid phase at flue gas temperatures or are adsorbed onto the surface of other particles [Hg(p)]. The presence of chlorine favours the formation of mercuric chloride ($HgCl_2$) at flue gas

cleaning temperatures. However, Hg^0 oxidation reactions are kinetically limited and, as a result, mercury enters the flue gas cleaning device(s) as a mixture of Hg^0, Hg^{2+}, and Hg(p). This partitioning of mercury into Hg^0, Hg^{2+}, and Hg(p) is known as mercury speciation, which can have considerable influence on the selection of approach for mercury control. In general, the majority of gaseous mercury in bituminous coal-fired boilers is Hg^{2+}. However, the majority of gaseous mercury in subbituminous and lignite-fired boilers is Hg^0. This means that mercury reduction strategies have to take coal characteristics into account.

A power plant may consider the following technology, techniques, and practices for mercury emission reduction:

- Use low-mercury coal or blending to ensure low mercury concentration on a fired basis;
- Coal-washing to reduce not only ash but also mercury content;
- Utilising co-benefits of air pollution control systems such as ESP, FF, FGD, DSI, SCR or SNCR or advanced systems like TOXECON in combination; and
- Retrofit powdered activated carbon (PAC) injection or halogenated PAC.

Control of mercury emissions from coal-fired boilers is automatically achieved, to a varied extent, through existing emission controls ESP, FF, FGD, SCR and SNCR as a co-benefit. Co-benefit mercury control may be low (below 10%) or may be up to 95%. The result is variable depending on multiple factors including the coal chemistry and the plant configuration, as shown in Table 9. ESP can provide limited mercury co-benefit control as only a fraction of the mercury is captured on particulates, whereas baghouses or FF offer greater mercury control since the residence time on the filter is longer, allowing more opportunity for mercury to adsorb to fly ash, especially to any unburnt carbon. SCR systems can also oxidise mercury, promoting its capture in downstream PM and SO_2 control systems. Dry FGD systems can absorb mercury into the dry by-product and wet FGD systems can capture mercury in both the wastewater and the gypsum (Sloss and others, 2023a).

TABLE 9 MERCURY REMOVAL (%) CO-BENEFITS WITH VARIOUS AIR POLLUTION CONTROL DEVICES (UNEP, 2017)

Air pollution control device combinations	Mean	Minimum	Maximum	Standard deviation	Number of tests
Wet PM scrubber	23	7	59	18	8
ESP cold-side	29	1	83	19	64
FF	67	9	92	30	10
ESP cold side+wet FGD	62	13	88	22	19
FF+wet FGD	86	77	97	10	3
SCR+ESP+ wet FGD	69	36	95	24	4
SCR+FF+wet FGD	93	86	99	9	2
ESP cold-side+CFB+FGD+FF	68	68	68		1

For mercury specific control, sorbents and oxidants are often used. Powdered activated carbon (PAC) is injected into the flue gas duct between the air preheater and the ESP or baghouse, typically in the 120-150°C range to provide an attractive surface to which mercury will adhere (*see* Figure 32). Mercury is absorbed by activated carbon which is collected at the ESP or baghouse. Baghouses/FF are more effective since the bags/filters become covered with an activated carbon layer which captures more mercury from flue gas. ACI with flue gas temperature control helps to optimise the temperature at which activated carbon absorbs mercury.

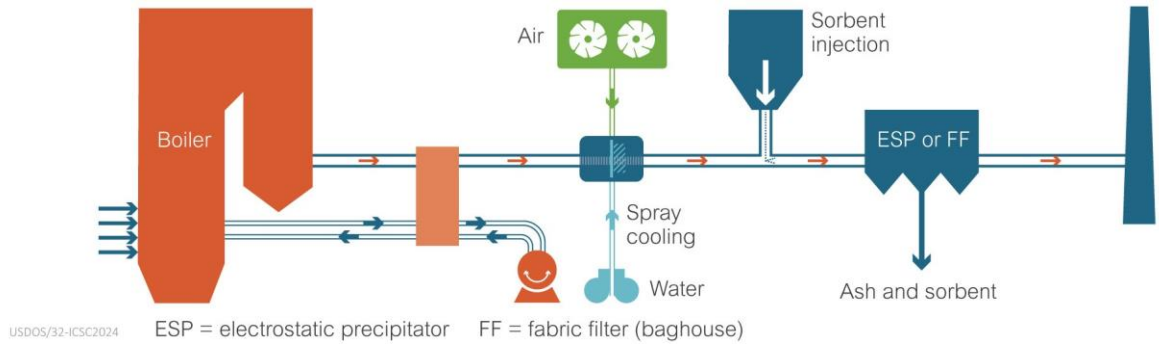

Figure 32 Schematics of ACI/sorbent injection for mercury control (Durham, 2003)

The injection location is determined by the plant configuration, especially any additional downstream PM control equipment. For example, to segregate collected fly ash from collected sorbent it may be beneficial to retrofit a pulse-jet FF downstream of an existing ESP and inject the sorbent between the ESP and FF. This arrangement is available in EPRI's TOXECON technology, as discussed previously. Sorbent injection can also be put between ESP fields (TOXECON-II) to enhance the useful collection of fly ash. The use of powdered sorbent injection can be employed in combination with existing SO_2 control devices. For example, powdered sorbent might be injected prior to the SO_2 control device or after the SO_2 control device, subject to the availability of a means to collect the powdered sorbent downstream of the injection point (USEPA, 2013). Factors that impact the ACI performance include:

- injection concentration of the sorbent measured;
- flue gas conditions, including temperature and concentrations of HCl and sulphur trioxide (SO_3);
- the air pollution control configuration;
- the characteristics of the sorbent; and
- the method of injecting the sorbent.

The selection of a carbon for a given application should take into consideration the total concentration of mercury, the relative amounts of Hg^0 and Hg^{2+}, the flue gas composition, and the method of capture (ESP/FF/FGD). ACI may be used either in conjunction with existing control technologies and/or with additional controls such as the addition of an FF. ACI has become relatively common on coal-fired plants in the USA and also on waste incineration units.

Oxidants such as halogens can be added in combination with sorbents to maximise mercury capture. Bromine (released from the bromine salt) is the most commonly used halogen as it has the greatest oxidation potential for mercury (Sloss, 2017). Alternatively, sorbents can be prepared with halogens in place – halogenated PAC are easier to handle than both ACI and oxidants separately. PAC with high chlorine contents can give around 90% mercury control at less than 170ºC flue gas temperature, whereas chlorine on its own can only remove up to 60%. Brominated PAC is the more effective option given the higher reactivity of bromine over chlorine. It is expected that total mercury removals would increase from 10–50% to 50–90%, even at higher temperatures, with brominated PAC injection.

A problem with PAC injection is the potential for poisoning by SO_3. The consumption of PAC increases as the concentration of SO_3 increases above 5 ppm and when the concentration of SO_3 increases to more than 15 ppm, the PAC becomes less effective for mercury removal. To mitigate this, a DSI should be installed to remove SO_3 before the point of injection of PAC. The larger the DSI unit, the greater the conversion of Hg^0 to Hg^{2+} and consequently the more efficient the mercury removal. The oxidised mercury can be effectively removed by wet FGD systems (Shahzad and others, 2017). Halogenated PAC has been employed at many plants including Plant Millar of the Alabama Power Company (USA) where the mercury concentration was reduced from 10 µg/m^3 to below 2 µg/m^3; Pleasant Prairie Plant (2 x 600 MW) in Wisconsin; and at numerous waste incineration plants in Germany and France (Sloss, 2017).

The Sanhe and Xuzhou Power Plants in China have used fly ash as the sorbent for mercury control. The fly ash is modified using an onsite mechanical brominated coupling method. The modified fly ash is uniformly injected into the flue gas before the ESP to adsorb and oxidise mercury in the flue gas. The former Shenhua Group adopted this technical route and carried out extensive engineering application research with the North China Electric Power University. The world's first 300 MW and first 1000 MW demonstration projects for mercury removal with modified fly ash were established in Unit 4 of the Sanhe Power Plant and Unit 2 of the Xuzhou Power Plant, respectively. After the mercury removal systems were applied, the removal efficiencies increased to 94.6% and 91.0%, respectively. In addition, the mercury removal efficiency of the ESP increased from 28.6% to 87.6%, indicating that the performance of modified fly ash on mercury removal is similar to that of ACI. The operation cost of this technique was CN¥ 51.3 (about INR 590; $7.1) for the removal of 1 gHg as compared to CN¥ 353.5 CN¥ (INR 4050; $48.9) for PAC (Wang, 2020).

5.5 CARBON CAPTURE, UTILISATION AND STORAGE

Carbon capture, utilisation, and storage (CCUS) is primarily intended for use at large point sources such as power plants or industrial facilities which use fossil fuels or biomass as fuel and emit substantial quantities of CO_2. Captured CO_2 can be used on-site or compressed and transported to end-use applications or injected (trapped and stored) into deep geological formations such as depleted oil and gas reservoirs or saline aquifers. To date, there are around 35 commercial facilities applying CCUS to

industrial processes, fuel transformation and power generation with a total 42.5 Mt/y capture capacity in addition to around 200Mt/y capture capacity is in the pipeline (IEA, 2022; GCCSI, 2022).

Commercially available CO_2 capture technologies include:

- solvent-based absorption which can use physical solvent or chemical solvent-based absorption;
- adsorbent-based adsorption; and
- cryogenic separation.

These technologies are summarised in Table 10.

TABLE 10 COMPARATIVE ANALYSIS OF VARIOUS CO_2 CAPTURE TECHNOLOGIES (NITI AAYOG, 2022)

Process	Working principle	Advantages	Limitations	Examples
Chemical solvent	• Chemical reaction between CO_2 and solvent • Governed by rate kinetics and thermodynamics	• High absorption at low partial pressure of CO_2 • Selective capture and high purity CO_2 product	• High energy (steam) requirements for solvent generation	• BASF/OASE® • ICE-21, ICE-31 • KS-1™, KS-21™ • UCARSOL™ • CAP
Physical solvent	• Absorption due to CO_2 solubility in the solvent • Governed by Henry's Law	• Suitable for gas streams with high partial pressure of CO_2 • Regeneration through low temperature flashing or pressure reduction • High absorption capacity and lower solvent recirculation rates	• Low energy efficiency for low partial pressure of CO_2 • High compression requirement for low pressure feed gas • H_2S often absorbed more effectively than CO_2	• Rectisol™ • Selexol™
Adsorption	• Selective adsorption due to difference in diffusivity and heat of adsorption • Governed by pressure change	• Selective capture • Can be performed at normal temperatures	• Batch process • Complex pressure balancing management system • High electrical energy consumption	• Pressure swing adsorption • Vacuum swing adsorption • Temperature swing adsorption
Croygenic separation	• Low temperature separation through liquefaction • Governed by temperature change	• Selective capture and high purity CO_2 • Liquefied CO_2 product • Food grade CO_2 • Almost no steam consumption • Low area footprint	• High energy requirement • High operating pressure	• Cryocap • Ortioff Dual Refrigerant CO_2 Fractionation (DRCF)

Additionally, there are membrane, microbial and algae-based CO_2 capture technologies, but these are currently still at the developmental stage.

CCUS could play a crucial role in the transition to cleaner energy systems in India through the evolution of hard-to-electrify CO_2-intensive sectors such as steel, cement, oil and gas, petrochemicals and chemicals, and fertilisers. CCUS could also accelerate a low-carbon hydrogen economy together with decarbonisation of highly required sources such as coal-fired power, cement, and steel plants. The key to a successful CCUS policy for India is a framework that supports the creation of sustainable

and viable markets for CCUS projects. Towards this aim, NITI Aayog completed a study on a 'CCUS framework and deployment mechanism' in November 2022 (NITI Aayog, 2022).

The capital cost and cash costs of carbon capture depend on:

- the CO_2 source characteristics (pressure and CO_2 concentration),
- the capture technology, and
- the power and steam sourcing costs.

The NITI Ayog study indicated that CO_2 capture costs are the lowest for gasification processes, as carbon capture is already integrated within the process. An additional cost of around INR 400/t (4.83 $/t) of CO_2 is estimated for polishing and compression of the CO_2 stream. The capture costs for other production processes such as steam methane reforming (SMR)-based hydrogen production, iron and steel, and cement include the costs for gas processing, carbon capture, and compression, and are consequently higher. As the CO_2 concentration is the lowest for coal-based power plants and other contaminant pollutants are present, the capture cost is the highest of all major industries. Since the CO_2 source characteristics are generally process-driven, the typical capture cost of CO_2 (including cash costs and capital charges) was estimated for a reference plant size for each sector and compressed CO_2 delivery from the plant gate at 10 MPa for each case.

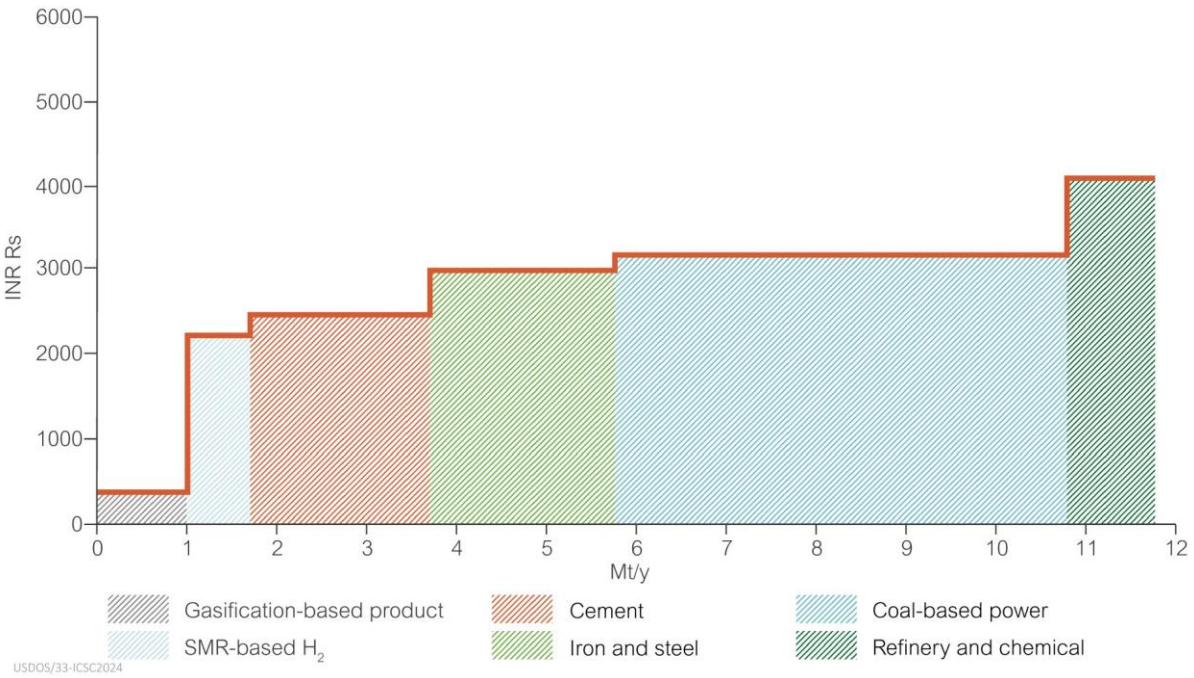

Figure 33 Comparative analysis of various CO_2 capture technologies appropriate in India (NITI Aayog, 2022)

Utilisation technologies and pathways for captured carbon are important components in the decarbonisation solution across all industries. Utilisation of the captured CO_2 is primarily for enhanced oil recovery, green urea production (conversion of green ammonia to green urea using the captured CO_2) and utilisation of CO_2 in food and beverage applications. Additionally, there are other promising

propositions for the utilisation of CO_2 including mineralisation to produce concrete and aggregates, the production of chemicals such as methanol and ethanol, creation of polymers including bioplastics. The ICSC has published a report on CO_2 utilisation (Zhu, 2024). Various utilisation pathways are depicted in Table 11.

TABLE 11 VARIOUS UTILISATION PATHWAYS FOR CO_2 CAPTURED BY CCUS (NITI AAYOG, 2022)

Product	Sub-category	Project and location	Technology provider	Production capacity	Quantity of CO_2 utilised
Building materials	Concrete	San Fransico Bay Aggregates LLC, USA	Blue Planet	33 kt/y (Phase-1)	14 kt/y (Phase-1)
	Concrete	Thomas Concrete, USA	CarbonCure Technologies	1.8 million yd^3 (1.37 million m^3)	4500 t/y (across its US operations)
	Lightweight construction aggregates	AVR's Energy from waste plant, Duiven, Netherlands	Carbon8 Systems	100 t of building product (pilot level)	–
	Concrete bricks	Ghent Footpath Construction, Belgium	Carbstone Innovation	Unknown	1 m^3 of Carbstone bricks stores a net 350 $kgCO_2$
	Concrete Masonry Unit (CMU)	–	Carbicrete	Unknown	3 $kgCO_2$ removed per CMU
Chemicals	Methanol	Shunli CO^2-to-methanol plant, China	Carbon Recycling International (CRI)	110 kt/y	15 kt/y
	Methanol	George Olah renewable methanol plant, Iceland	Carbon Recycling International (CRI)	4 kt/y	5.5 kt/y
	Methanol	ThyssenKrupp Duisburg steel plant, Germany	ThyssenKrupp	Unknown	Unknown
	Ethanol	Beijing Shougang LanzaTech New Energy, China	LanzaTech	60 kt (since May 2081	100 $ktCO_2$ (since May 2018)
	Ethanol	Steelanol, ArcelorMittal, Belgium	LanzaTech	80 million litres of bioethanol (aim)	-1.5 $MtCO_2$/y (aimed)
Polymers	Bio-plastics (AirCarbon)	Dell Latitude series laptop packaging Sprint cell phone cases KI plastic chair components	Newlight	>23 kt/y	Unknown
	Polyether carbonate	Cardyon mattresses, Germany	Covestro	10 kt/y	Mattresses formed of 20% CO_2

The world's first CCUS-equipped large-scale power plant began operation in Canada in October 2014 and was expected to capture around 1 $MtCO_2/y$. The $1.4 billion facility captures CO_2 released from its coal-fired Boundary Dam Power Plant near Estevan and transports it by pipeline to nearby oil fields to be used for enhanced oil recovery and deep underground storage (Royal Society of Chemistry, 2014). Since then, there have been numerous projects for CCUS worldwide, as shown in Figure 34.

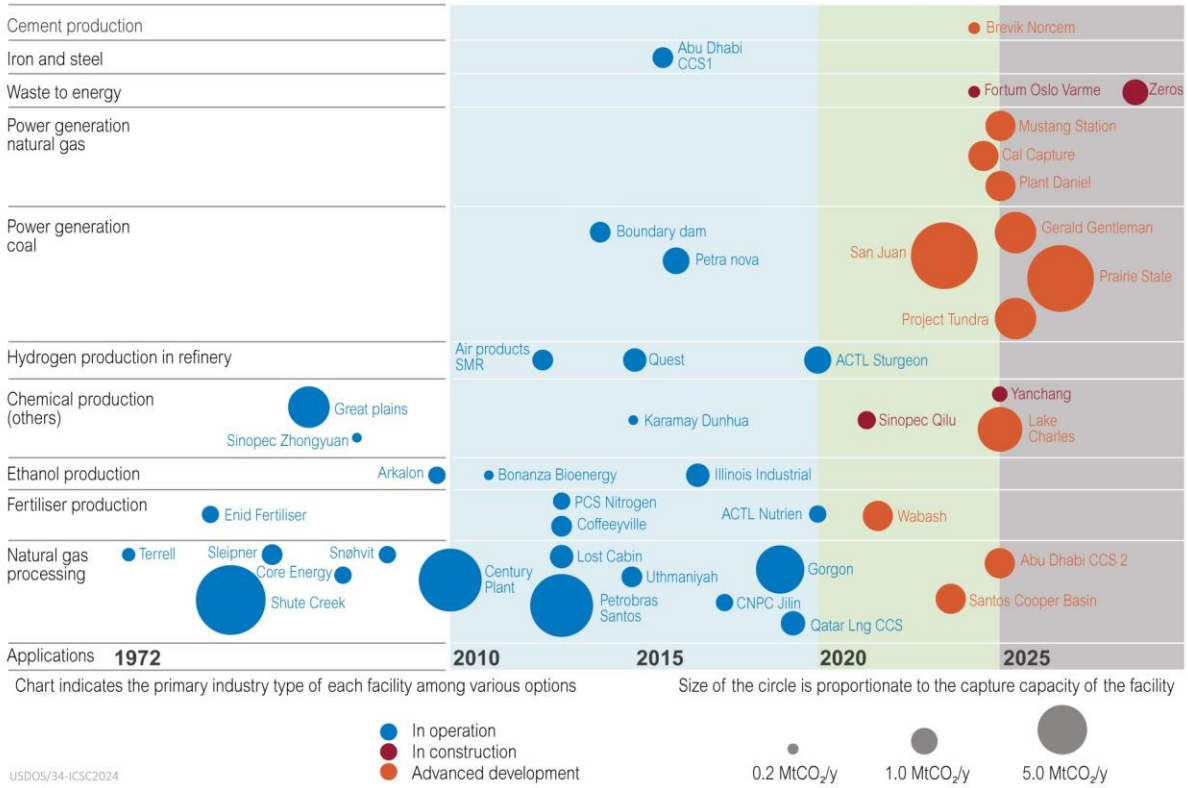

Figure 34 Major large-scale commercial carbon capture projects worldwide (NITI Aayog, 2022)

India's largest coal-fired power plant, the NTPC 4.8-GW Vindhyachal Super Thermal Power Station, has begun capturing CO_2 from plant flue gas as part of a foundational project to explore the conversion of CO_2 to methanol. This is designed and built by UK-based carbon capture solutions provider Carbon Clean and Green Power International, an engineering, procurement, and construction firm. The project will capture 20 tCO_2/d from a 500 MW unit using a modified tertiary amine. The pilot project, built for NTPC Energy Technology Research Alliance (NETRA), is part of an initiative launched by NTPC in 2020. NTPC expects that the project will comprise three parts (Powermag, 2022):

- a carbon capture unit;
- a hydrogen generation unit that will use high-temperature steam electrolysis to generate 2 t/d of hydrogen; and
- a methanol production unit that will convert the CO_2 to methanol through a catalytic hydrogenation process.

5.6 COMMENTS

Coal combustion releases significant quantities of pollutants such as PM, SO_2, NOx and mercury. New emission norms in India require the monitoring and control of these emissions. Since Indian coal and coal plants often differ from those in Europe, China, and the USA, where many control technologies were developed, it is not possible for Indian coal-fired plants to simply assume that standard control technologies will be as effective in India as they are elsewhere. In many cases, the high ash content of Indian coals will cause issues with pollution control devices. For example, standard PM controls such as ESP and fabric filters may require more frequent maintenance and repair due to the increased ash load. Primary NOx control systems, which operate by optimising combustion conditions, will have to take high ash issues into account. Similarly, flue gas controls such as FGD and SCR systems may have to be adjusted to Indian flue conditions. Before any decision is made on which control technology to install, the plant operator must consider the various options and how each may perform under plant-specific conditions. This commonly requires expert guidance. Despite the increased challenges introduced by high ash Indian coals, most control technologies can be adapted to ensure that the emission norms set in India can be met.

6 CONCLUSIONS

Coal-fired power plants are critical to the economy in India and will remain potentially important for decades to come. They will provide an important bridge to cleaner renewable power options. However, as they continue to operate, it is important that the emissions from these units are monitored and controlled.

The most cost-effective means to reduce all emissions from a coal plant is to improve its performance and efficiency. The higher the plant efficiency, the lower the amount of fuel required to produce the same amount of electricity – the lower the amount of fuel used, the lower the emissions.

For performance and efficiency improvement, coal-fired power plants are required to adopt the best practices, from coal beneficiation through flexible operation, better process technologies, improved raw material use, better pollution control and ultimately planning for potential carbon capture and storage.

Coal beneficiation, handling and processing have a high potential to improve efficiency and reduce resultant emissions and waste. Since India is known to have high ash coals, the cleaning of coal will reduce transport costs (per GWh of energy produced from the coal delivered). Improvement in coal handling will also reduce dust and pollution from the numerous stages through which the coal passes between the mine where it is produced and the boiler where it is combusted. Many of the techniques and technologies used to limit dust production and coal wastage will also decrease the loss of combustible material.

Prioritising and monitoring water use, for coal washing and for other plant operations, such as cooling and fly ash cleaning, is particularly important in regions of India where water is a scarce resource. Instead of using clean community water, coal plants can use processed wastewater from industrial sources and sewage plants. Water from the plant should be recycled for use where possible. In India, the recovery of water from both internal plant waste (ash piles) and external waste (sewage treatment systems) has been demonstrated at full scale.

Indian coal plants must flex more than any other fleet in the world due to the increase of VRE into the grid and the lack of alternative dispatchable capacity, such as natural gas. Subcritical coal plants were not designed to run in flexing mode and so the repetitive starting and stopping, heating, and cooling, can lead to significant damage and potential outages. Methods are available, such as the EPRI Flexibility Toolkit, which can help operators identify areas of concern and prioritise maintenance and repair. This approach will also improve plant efficiency at little or no additional plant running cost and is therefore a ‘win-win’ situation.

Improving plant efficiency will reduce the number of pollutants released per unit of energy produced. However, stringent new emission norms have been introduced in India which require the control of PM, SO_2, NOx and mercury. Since Indian coals have high ash contents, PM capture systems must work harder to reduce emissions and produce significantly more fly ash by-products. Most Indian plants use fabric filters and meet the new emission limits. However, some older units may need to upgrade or ultimately replace their PMN control systems.

SO_2 and NOx control systems are relatively new requirements in India and so most plants do not yet have them installed. The selection of the most appropriate technology must be determined on a case-by-case basis and, since there is limited experience with SO_2 and NOx control technologies on high ash coals and Indian plants, there may be a steep learning curve to ensure these systems work efficiently in India. It is therefore imperative that Indian coal plants share their experience with these systems to allow lessons learned to be shared efficiently across the coal fleet.

Currently, the emission limits for mercury in India are not challenging. However, mercury can be controlled relatively easily by maximising the co-benefit effects of PM, SO_2 and NOx technologies. It is therefore important that, as these systems are installed across the Indian fleet, knowledge is shared on the extent of mercury co-reduction. If and when mercury emission norms tighten in future, India can be ready to maximise co-benefit effects through the addition of oxidants and sorbents, where necessary.

For the moment, CO_2 control on Indian plants is not a legal requirement and the most cost-effective strategy to reduce CO_2 emissions from across the Indian coal fleet will be to increase plant efficiency.

Indian coal plants face challenges with respect to achieving high efficiency and low emissions. However, techniques and technologies are available which should accelerate plants to accomplish this goal.

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