Clean Coal Technologies for Power Sector and their Scope in SAARC Member States

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Energy for Peace & Prosperity

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Executive Summary

In 21st century, a major challenge faced by SAARC member states is poverty elevation with minimal climatic deterioration. Poverty elevation requires significant industrial development fueled by reliable, economical and indigenous energy resources. SAARC region possess limited furnace oil resources, abundant but significantly consumed natural gas resources and substantial coal resources. In this scenario, coal fired power generation is set to play a major role in power generation portfolio of SARRC member states in coming decades. Despite the recent efforts to enhance the share of electricity generation from renewable sources made by several countries in the SAARC region, coal is and will going to be the single largest source of power generation in near future, particularly in India, Pakistan and Bangladesh.

This inevitability of coal utilization for power generation in the region dictates that clean coal technologies must be employed to reduce environmental burden. 21st Century clean coal technologies offer higher efficiency with reduced pollutant emissions particularly NOx, SOx and particulate matter. In the upcoming coal fired power plants in SAARC region, more than 50% deploy supercritical technology coupled with Low NOx burners, flue gas desulfurization (FGD) units and electrostatic precipitators (EP). This trend will ensure that coal fired power generation will become cleaner from the past.

However, there are several areas that require immediate attention by the policy makers regarding coal fired power generation in the SAARC region. Deployment of integrated gasification combined cycle (IGCC) technology remains a key challenge. The major hurdle is contextualization of technology which is designed on low ash coals to indigenous coal resources. Research and development can be initiated targeted at specific deposits to develop dedicated gasifiers. Improving thermal efficiency of coal fired power plant indeed reduces carbon dioxide emissions, however, deep cuts in carbon emissions may only be realized by carbon capture and storage (CCS). Therefore, the need of the hour is to invest in IGCC and CCS.

Chapter 1: Introduction of the Study

In SAARC member states, provision of reliable, cheap and environment friendly energy portfolio is one of the major challenges to ensure sustainable development while addressing the increasingly pressing issue of deteriorating climate. Economic development, increasing population and urbanization are main drivers of energy demand in SAARC member states. According to key world energy statistics 2017, the primary energy supply has nearly increased from 2571 MTOE to 6510 MTOE between 1990 and 2015 in Asian countries. The share of SAARC member states in energy consumption will continue to increase within foreseeable future.

Coal contributes 39.3 % in global electricity generation and will continue to play a major role in delivering secure energy within in coming decades. Although, the share of coal in the energy mix is declining in developed countries like USA, China and UK, SAARC member states are planning to enhance the coal based power generation as the region has abundant coal resources. Particularly, the expansion of coal fired power generation in India and Pakistan will account for the major increase in coal utilization in the region. Governments of Bangladesh and Afghanistan have also planned to expand coal based power generation in near future. The region is all set for sustained coal utilization in decades to come and coal is going to play an important role in poverty elevation in the region. However, upcoming coal fired power plants in Pakistan, Bangladesh and India will only accounts for ~10% of India's coal utilization.

The role of clean coal technologies is significant in SAARC region as compared to other parts of the world. This report provides an overview of existing clean coal technologies, their application and potential in SAARC region.

1.1 Objectives of the Study:

The study has following major objectives:

1. To briefly describe existing clean coal technologies.
2. Highlight the existing clean coal technologies in operation in SAARC member states.
3. Outline the scope of clean coal technologies in SAARC region.

1.2 Methodology Adopted in the Study:

The methodology adopted in the study is primarily the review of open literature available and analyze the potential of clean coal technologies in SAARC region.

1.3 Limitations of the Study:

The main limitation of this study is availability of pertinent data and literature. Efforts have been made to access all relevant literature.

Chapter 2: Description of Clean Coal Power Generation Technologies

2.1 Power Generation from Coal:

Estimated coal reserves across the globe amount to 1 trillion tons that are sufficient to last about 150 years at current consumption levels. Geographical spread of coal (See Figure 1) and cheap production cost makes it most suitable source of energy. Consequently, coal is the single largest source of power generation around the globe providing nearly 40% of world's electricity. Since its development in late 18th Century, electricity generation from coal has been continuously improving in terms of efficiency improvement, emission reduction and process control.

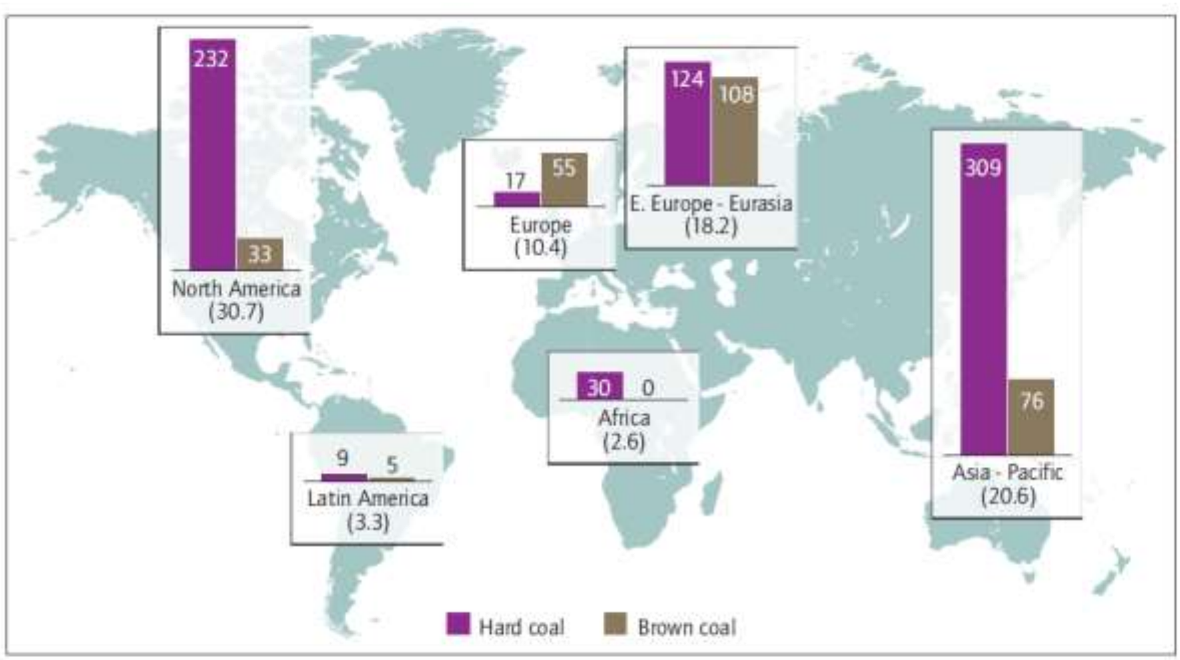


Figure 2.1: Geographical Spread of Coal

However, the challenging goal of sustainable development requires provision of cheap, reliable and environment friendly electricity. To achieve this goal, it is essential to develop high efficiency coal fired power generation technologies with near-zero emissions. Geographical spread of coal, mature industrial scale production & consumption technologies and low cost make coal irreplaceable source of power generation in decades to come. Research and development efforts are focused on efficiency improvement, co-firing coal with biomass, and carbon capture and sequestration to achieve the objectives of sustainable development.

Modern coal fired power generation plant is schematically represented in figure 2 below. Briefly, heat is generated from combustion of powdered coal. The generated heat thus converts water into steam at various temperature and pressure range. To minimize the emission of pollutants from combustion 3 major systems are applied including NOx reduction system, Electrostatic Precipitator (EP) and Flue Gas Desulfurization system. In addition to pulverized coal combustion, two more systems are employed for coal combustion mainly on small to medium scale plants including Fixed Bed Combustion System and Fluidized Bed Combustion System. Selection of combustion systems depend upon coal properties, efficiency requirements and load of the power plant.

Among the three widely used coal fired power generation technologies, fixed Bed Combustion is least efficient technology due to limited gas solid contact. Fluidized Bed Combustion is the most versatile technology for coal fired power generation which can utilize low quality coals, various biomass species, waste fuels and coal-biomass mixtures. Another major advantage of fluidized bed combustion is lower SOx emission owing to limestone injection within the combustion process. However, large scale power plants employ pulverized coal combustion due to high combustion temperatures and efficiencies. This technology is employed in up to 90% modern coal fired power plants.

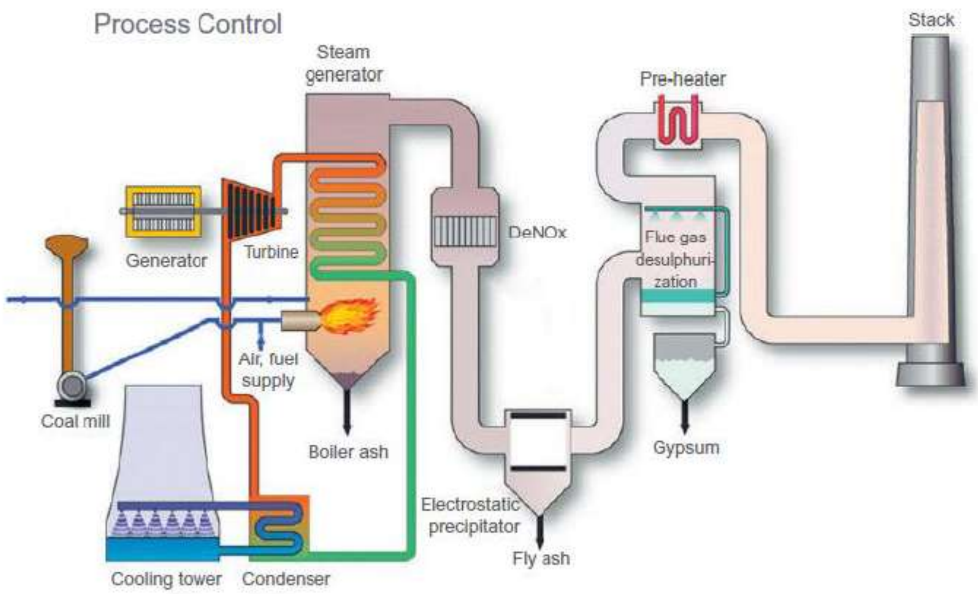


Figure 2.2: Schematic Diagram of Electricity Generation from Coal

2.2 Fixed Bed Combustion:

Fixed Bed Combustion technology has been used in the early 19th Century for coal based power generation. Initially, Fixed grate boilers were used for combustion, however, improvements in coal feeding and ash removal systems led to the development of chain grate boilers. Fixed bed boilers offered advantages like low particulate matter (PM) emission, ease of operation and use of crushed coal instead of pulverized. However, these advantages are largely offset by disadvantages like; high maintenance cost, in-efficient gas solid contact and inability to burn coals with caking and low ash fusion temperature properties. Even though most of the chain grate boilers have become obsolete from the developed countries, there are a number of small capacity units being installed for captive power generation in developing countries like India and Pakistan owing to smaller capital costs and easier operations. The tradeoff between cost saving from higher efficiency with advanced coal based power generation technologies against chain grate boilers with low efficiency is largely governed by coal prices. Since the coal prices have been on the lower side for the last 10 years, small industries with requirement less than 20 MW often favor cheap chain grate boilers.

2.3 Fluidized Bed Combustion Technology:

Fluidized bed combustion (FBC) has good fuel flexibility and reduced emissions compared to conventional stokers and pulverized coal combustion (PCC) boilers. It has been used to burn all types of coals, coal wastes and a wide variety of other low-quality fuels such as biomass and wastes, either singly or in conjunction with coal. In particular, it is suitable for those coals which are difficult to mill and fire in conventional stokers and pulverized coal combustion boilers.

During the past decades, FBC technology has undergone considerable technological and commercial developments towards improved performance and lower capital costs. It has found a variety of applications ranging from small industrial boilers and furnaces to large power generation units. FBC has now become the most widely applied clean coal technology after PCC with flue gas desulphurisation (FGD). However, the technology currently operates at relatively small sizes. CFBC boilers currently in operation have a maximum size of 300 MWe, while larger units up to 460 MWe are under construction. At present, the technology represents only about

2% of the total coal-fired capacity worldwide. However, this percentage is expected to increase with a wider spread of FBC within the next few decades.

Fluidised bed coal combustion differs from both conventional stokers and pulverised coal combustion. It uses a continuous stream of air to create turbulence in a mixed bed of inert material and coarse fuel ash particles. At suitable gas velocities, the particles remain suspended and move about freely or become entrained in the gas stream. In this state they behave like a fluid, in other words, the bed becomes fluidized. When fuel is added to a hot fluidized bed, the constant mixing of particles encourages rapid heat transfer and good combustion. It also allows a uniform temperature to be maintained within the combustion zone. Heat generated is recovered by in-bed water tubes (with a BFBC boiler), waterwalls, superheater/reheater sections, economizer and others. Flue gases leaving the combustion system are cleaned of solid and gaseous pollutants and then discharged into the atmosphere.

FBC offers a number of significant advantages over conventional pulverised coal combustion systems, including:

1. The bed can be operated at temperatures typically 800–900°C (in some cases, as high as 950–1000°C) above which ash may melt and form slag;
2. The scrubbing action of the moving particles on the immersed water tubes increases the rate of heat transfer;
3. the bed has a substantial thermal capacity which allows a variety of fuels to be burned, including low-quality fuels with a high ash or moisture content as well as mixed fuels;
4. NOx formation is reduced because the combustion takes place at relatively low temperatures and the system offers opportunities for air staging;
5. Typically 90% of the SO2 released during combustion can be captured in the bed by adding a suitable sorbent such as limestone or dolomite.

As noted above, FBC boilers can operate with quite different fuels. However, there are limitations on the use of fuels outside the designed range. Operations with fuels outside the designed range may deteriorate the boiler performances. There are also some disadvantages with FBC technology:

1. Commercially proven only at relatively small scales compared with pulverised coal combustion;
2. Relatively large amounts of solid residues generated (with sorbent addition), some of which require special measures for disposal;
3. Higher carbon-in-ash levels than those from pulverised coal combustion;
4. Increased N2O formation (with coal/coke or similar fuels) due to the lower combustion temperatures.

There are four different forms of FBC. In terms of the fluidising gas velocity, FBC can be divided into two groups: bubbling fluidised bed combustion which takes place at low gas velocities; and circulating fluidised bed combustion which occurs at higher gas velocities. In terms of operating pressure, there are also pressurised bubbling fluidised bed combustion and pressurised circulating fluidised bed combustion. Accordingly, the four derivatives differ largely in their designs although there are some common features.

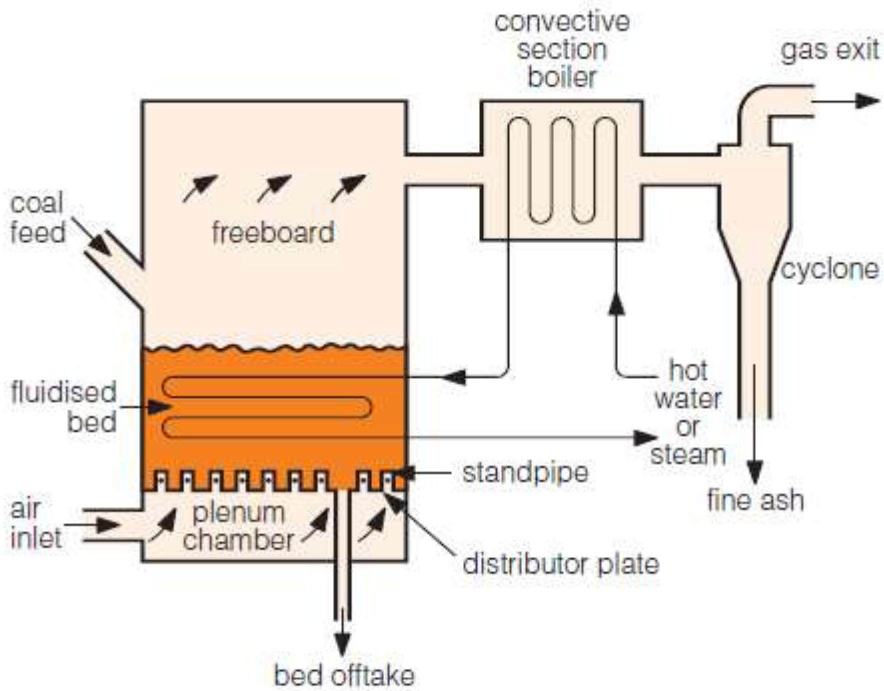


Figure 2.3: Bubbling fluidised bed combustion system

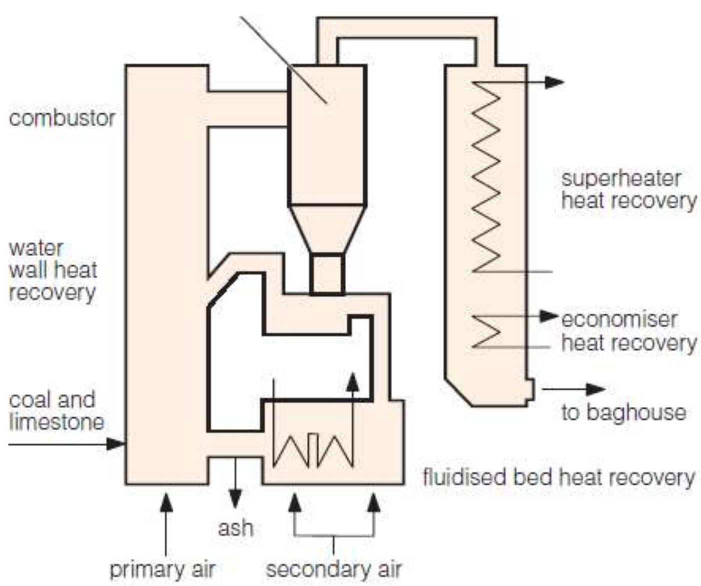
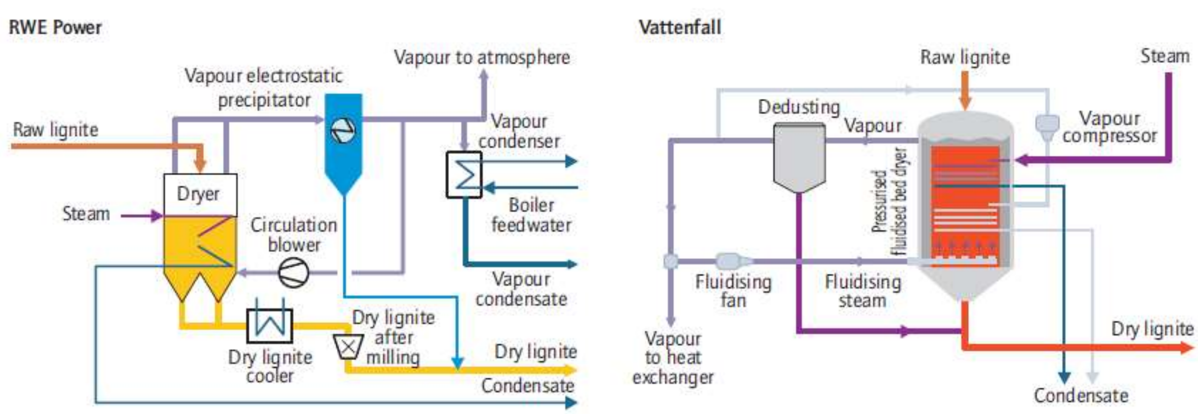


Figure 2.4: Circulating fluidised bed combustion system

2.4 Pulverized Coal Combustion:

Pulverized coal combustion currently most employed technology and the centerpiece of advanced coal firing developments (Figure 2.5). Pulverized coal firing is a mature technology and has been a subject of extensive research and development.

Briefly, coal is ground by crushing and milling operations so that 70-80% particles are less than 200 Mesh size. This pulverized coal is carried into the boiler by means of primary air. Once this coal enters the combustion chamber rapid combustion takes place yielding temperatures in the range of 1400-1700°C. Exothermic energy thus generated is captured initially through radiative heat transfer in super heater of the boiler system. Heat transfer in the steam tubes occurs by convective mechanism at lower temperatures. Flue gasses pass through the economizer around 300°C which functions to preheat the boiler water. Afterwards, flue gasses are carried into primary air preheater at about 150°C. In a typical power plant, gas cleaning systems are employed afterwards which include electrostatic precipitator to remove particulate matter and desulfurization system which removes SOx from the flue gas.



Note: RWE Power's WTA process shows one of several process variants being developed and tested.
Source: RWE, 2010; and Vattenfall, 2011b.

Figure 2.5: Schematic Diagram of Pulverized Coal Combustion System

Pulverized coal based power generation has been the key focus of development and several technologies have been developed to improve the efficiency of power generation. Efficiency improvement not only reduces the cost of power generation but also limits greenhouse gas emissions. However, significant reductions in emissions can only be implementation of achieved by carbon capture and sequestration technologies. Technological improvements in pulverized coal combustion include deployment of supercritical, ultra-supercritical, advanced ultra-supercritical and Integrated Gasification Combined Cycle (IGCC) Technologies which are briefly discussed below (Table 2.1);

Table 2.1: Features for Current Available Technologies for Coal based Power Generation

Technology	Steam Pressure	Thermal Efficiencies (LHV, Net)	Overnight Cost	Coal Consumption	CO_2 Intensity Factor
Subcritical	Below Critical Pressure of water 22.1MPa	up to 38%	USD 600/kW to USD 1980/kW	≥380 g/kWh	≥880 g CO_2/kWh
Supercritical	24.31 to 26.52 MPa	up to 42%	USD 700/kW to USD 2310/kW	340-380 g/kWh	800-880 g CO_2/kWh
Ultra-supercritical	Up to 620°C, with 25 MPa to 29 MPa	up to 45%	USD 800/kW to USD 2530/ kW	320-340 g/kWh	740-800 g CO_2/kWh
Advanced Ultra-supercritical	700°C to 760°C and pressures of 30 MPa to 35 MPa	45-50%	Alloy Under Development	290-320 g/kWh	670-740 g CO_2/kWh
IGCC	1500°C	45-50%	USD 1 100/ kW to USD 2860/kW	290-320 g/kWh	670-740 g CO_2/kWh

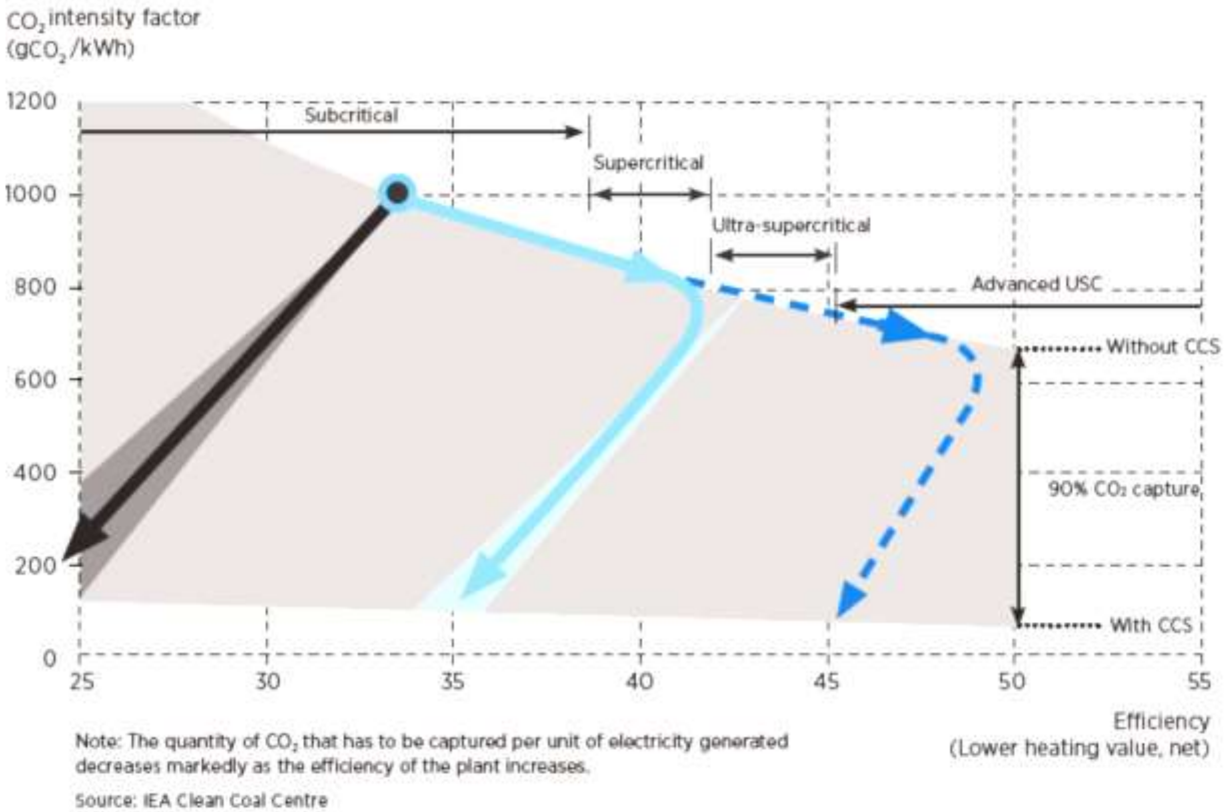


Figure 2.6: Effect of Steam Conditions in CO2 Emissions and Thermal efficiency of Pulverized Coal combustion.

Increase in steam temperature increases the thermal efficiency of coal fired power plant. Whereas subcritical plants only achieve efficiency up to 38%, super critical and ultra-supercritical technologies can boost thermal efficiencies to 43 % and 46% respectively. Increasing thermal efficiency reduces CO_2 emissions generated from above 1100g CO_2/kWh to nearly 800 g CO_2/kWh with ultra-supercritical technologies in place. This reduction in CO_2 emissions reduces the quantity of CO_2 to be sequestered. Obviously, in order to achieve near zero emissions from coal fired power plant, it is imperative to capture and store CO_2.

The major problem for the implementation of ultra-supercritical and advanced ultra-supercritical technologies is the development of materials capable of handling high steam temperatures and pressures. Research and development is required to develop Ni-Based alloy to commercially apply advanced ultra-supercritical technologies.

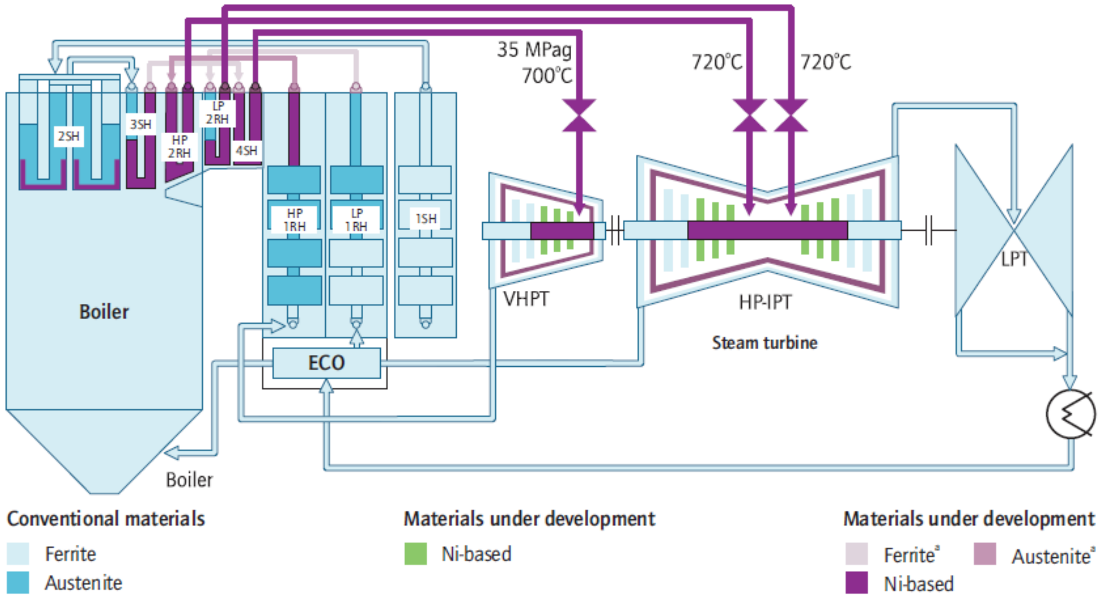


Figure 2.7: Development Status of Materials for Advanced Ultra-Supercritical Steam Cycle

2.5 Integrated Gasification Combined Cycle

A simplified version of a coal-fueled IGCC cycle is shown in Figure 2.8. Like all combined cycles, it employs gas and steam turbines but the fuel gas for the gas turbine is first prepared by gasification of the coal followed by gas cleaning. Current gasification technologies and detail principles of IGCC has been detailed elsewhere[1]. Gas cleaning is typically affected by water scrubbing or dry removal of solids, followed by hydrolysis of COS to H_2S, then scrubbing to remove H2S. There are many possible configurations, because gasifier designs vary significantly and IGCC has a large number of process areas that can use various technologies. The deep cleaning needed to protect the gas turbine enables emissions of particulates and SO_2 to be very low. Totally dry gas clean-up at elevated temperatures may eventually be applied, with advantages in efficiency, but is not currently available for commercial IGCC.

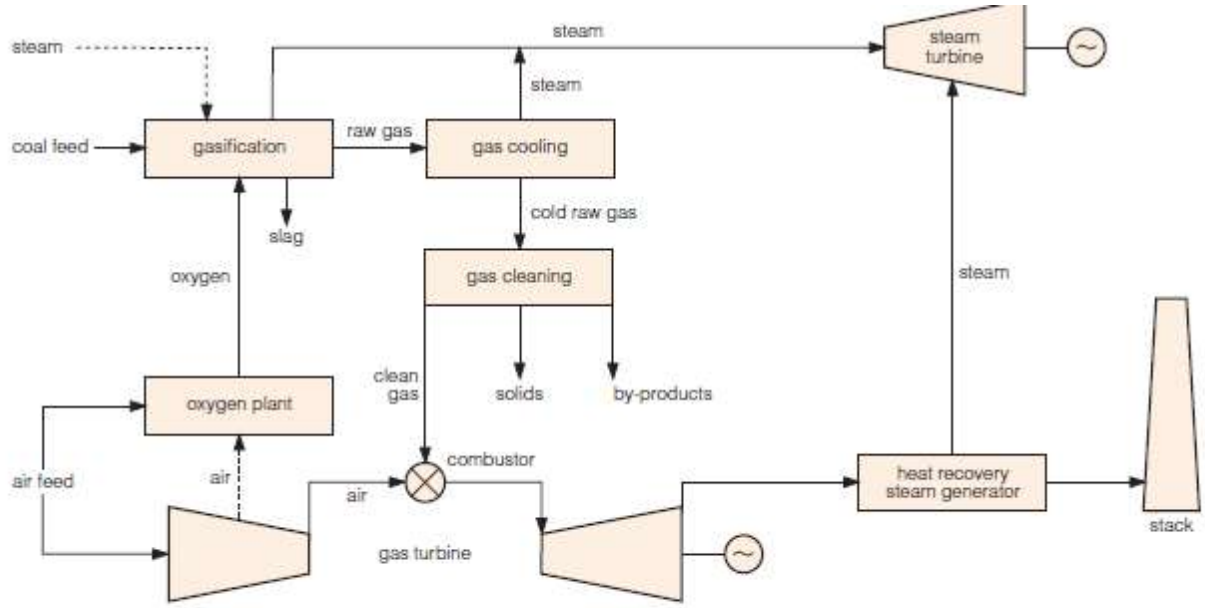


Figure 2.8: Schematic Representation of Integrated Gasification Combined Cycle

There are three general types of gasifier: entrained bed, moving bed, and fluidised bed. IGCCs have usually been based around entrained gasifiers because of their fuel flexibility, their production of high pressure steam, and the lack of tars in the product gas. Entrained gasifiers operate in slagging mode, and most are oxygen blown. Steam is also usually needed if the coal is not fed as a water slurry. The oxygen production plant can take its compressed air supply from the gas turbine compressor or from separate motor driven compressors or a combination of both (partial integration). Higher degrees of integration favor higher thermal efficiency. Highly integrated designs exhibit long start-up times, as individual process areas need to be brought on-stream in correct sequence, and some flexibility is lost in comparison with less integrated, lower efficiency designs. Partial integration is favored for future designs as it gives more rapid start-up and greater operating flexibility, while maintaining the efficiency advantage of gas turbine air extraction. Retention of integration of oxygen production also allows integration of nitrogen supply arrangements for fuel gas dilution for NOx minimization and better use of available low-grade heat. It also gives higher mass flow through the turbine, for better stability and performance.

Other gasifier types are being promoted for IGCC, including the BGL moving bed system, the HTW fluidised bed gasifier, HRL's IDGCC (Integrated Drying Gasification Combined Cycle) fluidised bed process and the Transport Gasifier. Moving bed gasifiers, while widely used for other applications at present, are probably unlikely to move extensively into IGCC because of their high production of tars. The fluidised beds are basically air-blown systems, EPIC's moving bed gasifier is also air blown and, unusually, MHI's entrained gasifier is also air blown with a small degree of oxygen enrichment. Air blowing avoids the cost of a large oxygen plant, and MHI and EPIC claim higher efficiencies than for oxygen-blown IGCC, although such advantages remain to be demonstrated. Net efficiency for the existing IGCC plants is up to 41%, HHV basis, on bituminous coals (43% LHV basis), as obtained at NUON's Shell Coal Gasification Process-based IGCC plant at Buggenum in the Netherlands with a Siemens 2 Outline of IGCC.

2.6 Typical Clean Coal Technologies

Clean coal technologies comprise a set of techniques aimed to reduce the environmental burden of coal usage. These technologies can be classified as pre-combustion, during combustion and post combustion technologies and will be discussed below:

2.6.1 Pre-Combustion Clean Coal Technologies

Pre-combustion cleaning of coal provides significant benefits for coal utillization including:

- Increased coal reserves;
- Lower transportation costs;
- Improved utilization properties and
- Abatement of pollutants
    - Sulfur Related Emissions
    - Particulate Matter Emissions
    - Hazardous Pollutant Emissions

Coal preparation technologies play a significant role in reducting the environmental burden of coal. Sulfur occurs in coal as three distinct forms (sulfate, organic, and pyritic). Sulfate sulfur is present in very small quantities and is not considered a serious problem. Organic sulfur, which is part of the basic structure of coal, is not removable by conventional cleaning.

The precombustion removal of organic sulfur is possible using chemical cleaning methods; however, these elaborate processes are not economically competitive with flue gas scrubbing. Pyritic sulfur is present as discrete inclusions of iron sulphides distributed within the coal matrix. As such, this form of sulfur can be removed by physical cleaning processes such as coal preparation. Coal preparation plants have been reported to remove up to 90 percent by weight of pyritic sulfur, although rejections are typically in the 30–70 percent range because of liberation constraints. When compared to the postcombustion control of sulfur, coal preparation offers several distinct advantages, including improved market flexibility, lower scrubber loading, and concurrent removal of other impurities (e.g., ash, trace elements, and moisture). Although coal preparation does not directly affect the nitrogen content of coal, washing has been shown to help reduce Nox emissions by providing a consistent high-quality fuel that provides for ease of control of the combustion environment. Noncombustible impurities present in the feedstocks supplied to coal power stations generate waste streams as either bottom ash/slag or fly ash. Of these, the finest particles of fly ash emitted to the atmosphere are considered to be of greatest environmental concern because of their potential adverse impact on human respiratory health. Power stations make use of several types of effective control technologies to minimize fine particulate emissions. These postcombustion technologies include efficient processes such as electrostatic precipitators (ESPs), fabric filters (FFs), cyclones, and wet scrubbers. Modern control systems typically achieve better than 99.5 percent removal of all particulates and exceed 99.99 percent in some cases. However, standards for particulate emissions continue to become increasingly stringent as reflected in expanded regulations by the Environmental Protection Agency (EPA) to include particles smaller than 2.5 microns in new ambient air quality standards. As such, there is continued interest in removing greater amounts of particulates upstream of other emission controls using coal preparation technologies. The separation processes used in coal preparation plants remove noncombustible minerals that ultimately affect the amount and type of particulate matter (PM) that passes downstream to emission control systems. For these systems, proper levels of coal washing can be identified that effectively reduce ash loading and improve removal efficiencies. A recent presentation by

American Electric Power to the Asia Pacific Partnership concluded that "Consistent and proper quality coal is best tool to improve plant operating performance and reduce PM and SO2 emissions. Removal of some of the coal ash (includes rocks) at the mine is more economic than in the pulverizer, boiler, precipitator and scrubber." Washing also minimizes the total amount of high-surface-area fly ash that is more hazardous to dispose because of its high reactivity. In cases where particulate controls are currently deemed adequate, greater use of coal preparation may be required in the future to compensate for deterioration in feedstock quality as higher-quality coal reserves become depleted.

Some of the most noteworthy hazardous pollutant elements preseat in coal are antimony, arsenic, beryllium, cadmium, chlorine, chromium, cobalt, fluorine, lead, manganese, mercury, nickel, selenium, and radionuclides. Concentrations of these elements are known to vary considerably from seam to seam, and in some cases within the same seam During combustion at electrical utilities, these elements may be released to the atmosphere as solid compounds with the fly ash and in the vapor phase with the flue gas. Existing post-combustion control technologies, such as electrostatic precipitators, can be reasonably effective in reducing the concentration of trace elements associated with fly ash. These elements commonly include antimony, beryllium, cadmium, cobalt, lead, and manganese. Capture efficiencies greater than 97 percent have been reported for electrostatic separators. On the other hand, trace elements such as arsenic, chlorine, mercury, and selenium have the potential to volatilize and are less-effectively controlled by postcombustion methods. Studies have shown that many of the hazardous air pollutant precursors are associated with mineral matter commonly rejected by coal preparation plants. This approach to trace HAP control is attractive, because the waste rock rejected by coal preparation plants is coarser and has a lower reactivity than the high-surface-area ash generated by power stations. In-plant sampling campaigns conducted by various researchers suggest a good correlation between the rejection of mineral matter and the removal of trace elements during physical cleaning. These findings are also supported by laboratory float-sink tests performed using a variety of eastern coals. These data suggest that trace elements are typically rejected at levels of 40 to 70 percent by weight using conventional preparation technologies. These values appear to be in good agreement with earlier values reported by

Fonseca et al. (1993), which showed an average trace element removal by conventional coal preparation of approximately 64 percent for six different coals. On the other hand, the large degree of variability observed in the data from these and other studies suggest that the rejections of trace elements by coal preparation are very site specific and need to be quantified on a case by case basis.

Mercury is the trace element in coal of greatest environmental concern. Mercury can be released during coal combustion and subsequently deposited in the environment. Ecological studies have shown that mercury bioaccumulates in the food chain as higher species consume lower life forms exposed to mercury contamination. Data reported by US EPA indicate that coal-fired utilities are currently the largest human-generated source of mercury releases in the United States. It is estimated that these plants release approximately 48 tons annually. To curb these emissions, US EPA issued the world's first-ever rule to cap and reduce mercury emissions for coal-fired power plants in March 2005. Compliance options available to utilities include postcombustion capture of mercury by existing or new flue gas scrubbing technologies as well as precombustion control of mercury by coal preparation and coal switching. A recent study by Quick et al. (2002) showed that the mercury content of coal delivered to utilities (based on ICR data) was lower than that of the inground coal resources in the United States (based on COALQUAL data).

Coal preparation involves a number of unit operations. As a matter of fact, the processing happens to be complicated because of the heterogeneous nature of coal, which needs to be addressed for making it acceptable after mining. Generally, the processing encompasses particle sizing, cleaning and dewatering and all of these steps are repeated sequentially for maintaining efficiency [2]. Figure 2.9 displays unit operations involved in sizing, cleaning and dewatering.

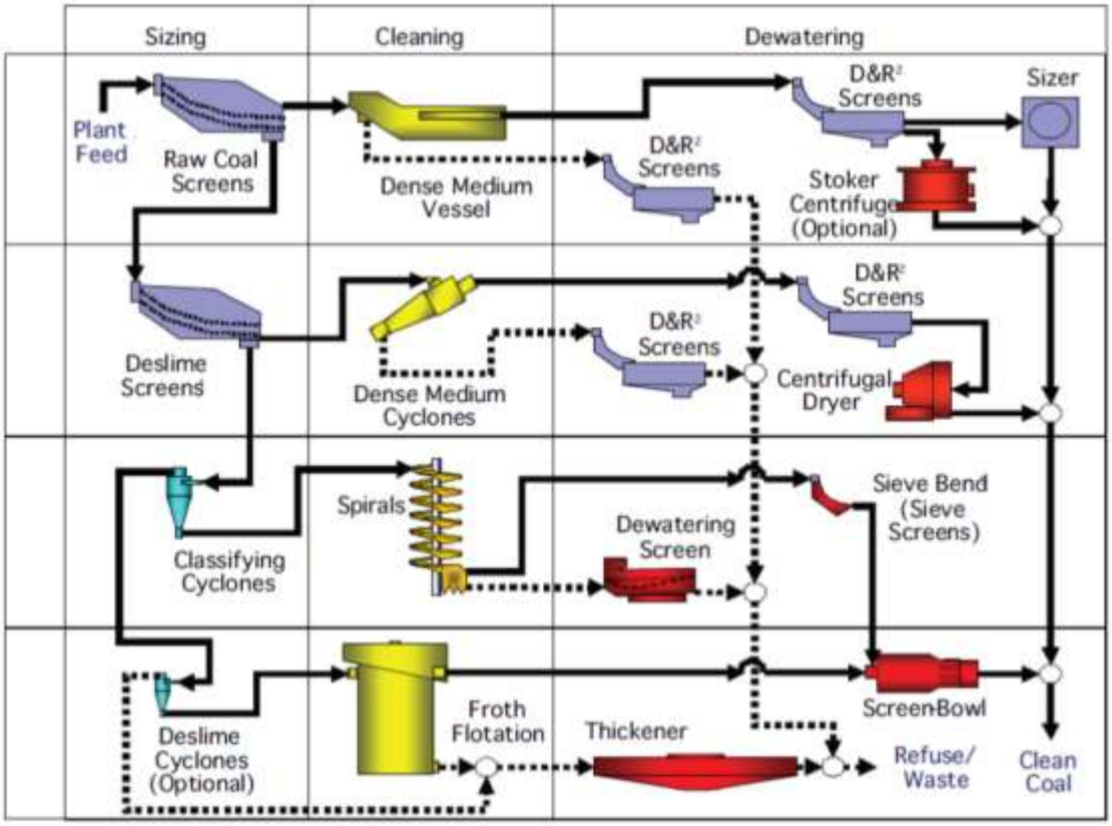


Figure 2.9: Overview of Coal Processing

In United States, four dedicated and separate processing circuits are employed for treating a range of particle sizes including, 1) greater than 10 mm, 2) between 1 and 10 mm, 3) between 1 and 0.15mm and less than 0.15mm, which may be regarded as coarse, small, fine and ultrafine, respectively [2]. A typical pant manages the sorting of feed coal into narrow particle sizes with the help of vibrating screens for coarser particles and for fine particles, classifying cyclones are employed. Chain-and-Flight Dense Medium Vessel (DMV) is used for the cleaning of coarse fractions, while Dense Medium Cyclones are specifically used for the upgrdation of smaller fraction [2]. The basic mechanism behind the operation of these processes is the exploitation of suspension for separation of coal from minerals on the basis of differences in particle densities. The cleaning of fine fraction can be carried out using spirals, water-only cyclones or combination of these may also be employed. The basic principle employed in water based processes is the differences in particle sizes or shape of the particles and density [2].

The efficiency of each processing technology depends on particlualr coal size (Figure 2.10).

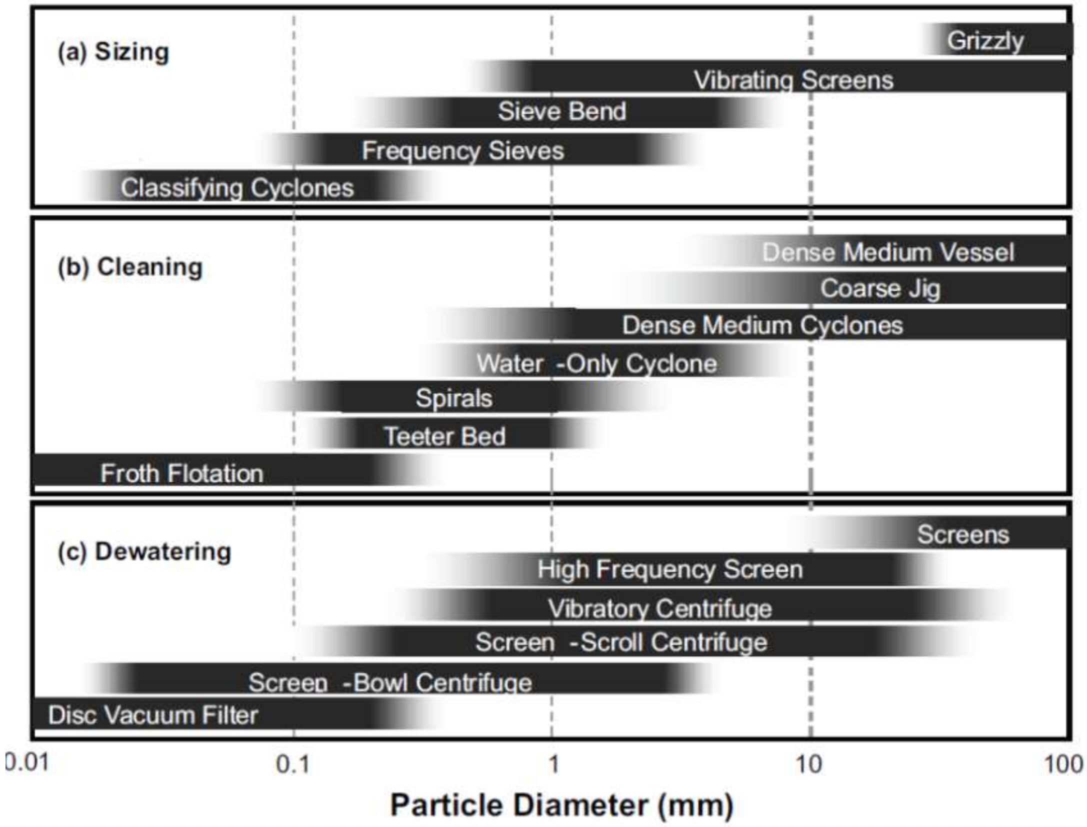


Figure 2.10: Overview of Techniques with respect to Particle Size for Coal a) Sizing, b) Cleaning c) Dewatering

Conventional density separators may not find application in the upgradation of ultrafine fractions because of the low mass of the very small sized particles. For ultrafine particles, froth flotation is generally used which works on the principle of differences in the surface wettability of organic and inorganic fractions. However, in a number of cases, ultrafine fraction may be resized ahead of flotation for the removal of particles which are under 40 microns or known as slimes and these are supposed to be harmful for the flotation process and subsequent dewatering processes. Lastly, the water employed in all processes is removed from the particles using a variety of screens and centrifugal dryers (basket type). Sometimes, coal particles manage to retain higher amount of moisture for which screen-bowl centrifuges or vacuum filters are used [2].

Particle Sizing: Mechanized mining operations produce a range of particle size including quite fine coal in powder and hundred millimetres as coarser particles. After crushing of coal to an appropriate particles size, the size classification of the feed coal is carried out using a number of equipment [2].

Screens are sizing devices, which sort particles into fine and coarse (Figure 2.11). These are most common and shaking rotating mechanism segregates particles on screen surface. The use of high-frequency screens manages the rapid passage of fine particles and use for the removal of moisture from fine coal (Figure 2.12) [2].

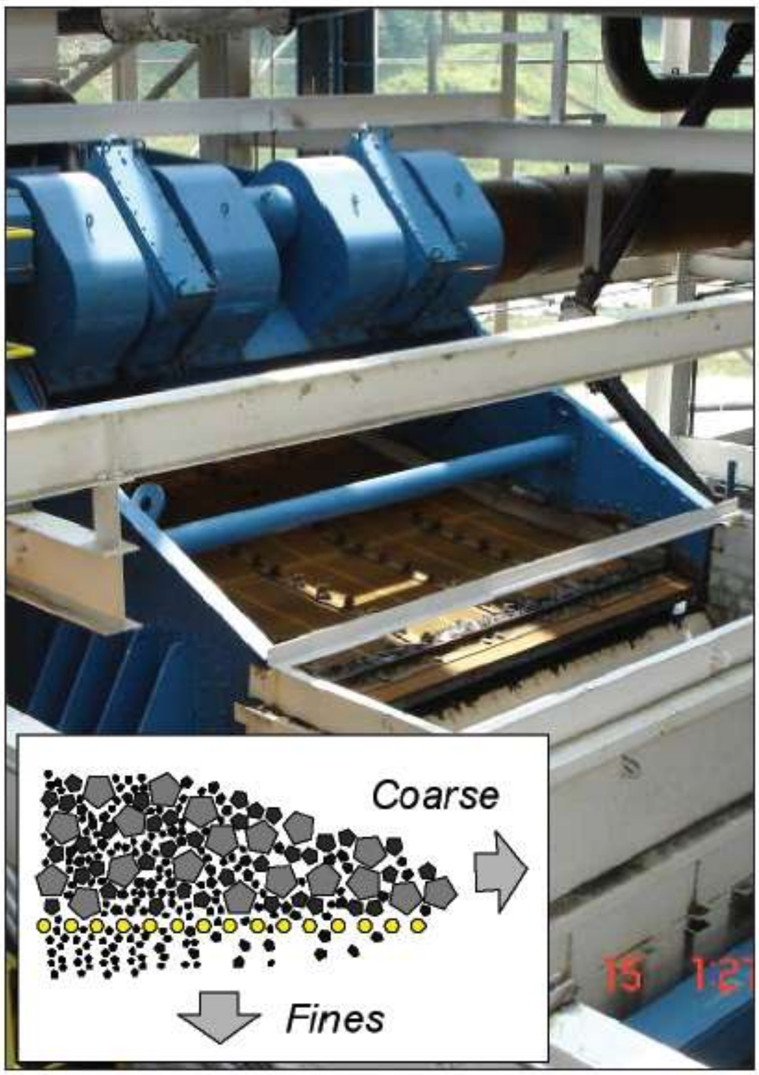


Figure 2.11: Vibrating Screens

Figure 2.12: High Frequency Screens

Sieve Bends and Classifying Cyclones: The sizing of fine coal become difficult because of the low capacity and increased chances of plugging in screen openings, therefore, sieve bends and classifying cyclones are employed for overcoming this limitation. The curve plate on sieve bend helps in slicing the material from flowing stream. The placed slotted bars in the path of the stream manages the sizing of the particles (Figure 2.13). Cyclones are applicable where the range of particles between 0.10 to 0.15 mm and it represents the only practical option for sizing the ultrafine particles. The working principle, operative in sizing devices, is the difference in settling rate of particles of different sizes. Generally, smaller particles take time in settling while larger particles settle rapid, comparatively (Figure 2.14) [2].

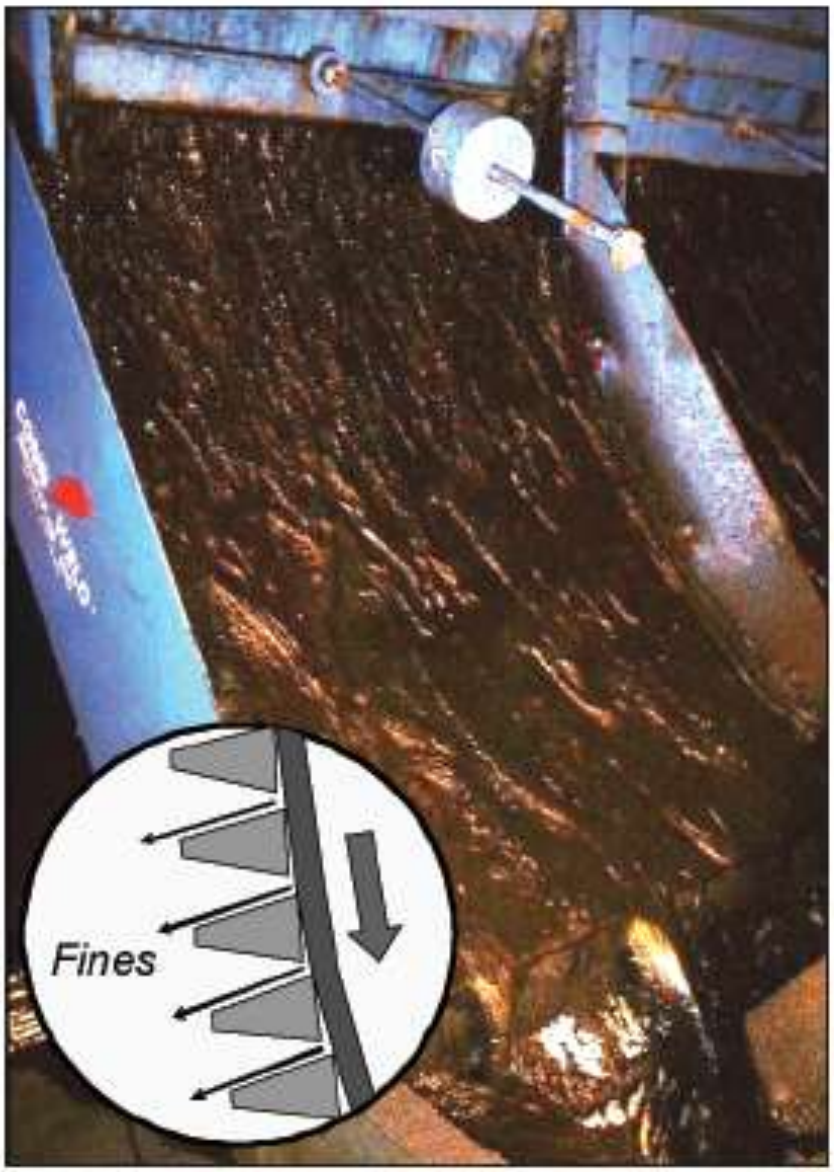


Figure 2.13: Sieve Bends

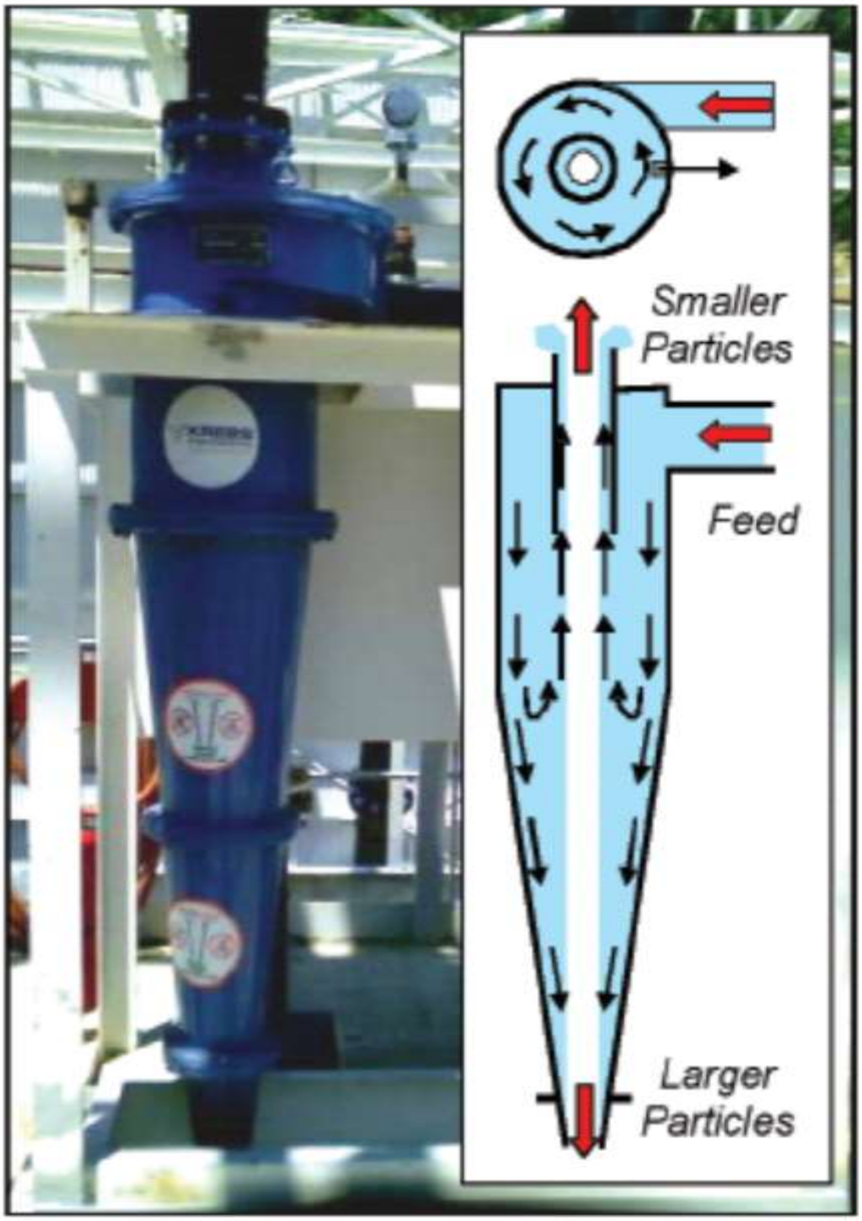
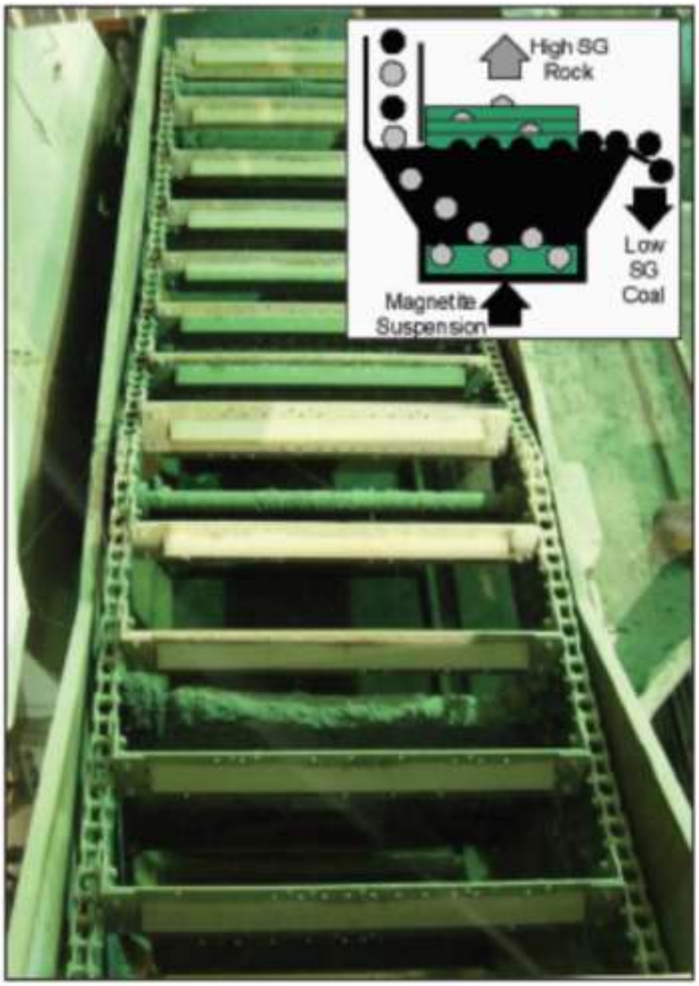


Figure 2.14: Classifying Cyclones

Solid-Solid Separation: The valuable carbonaceous material from inorganic materials is important and can be exploited on the basis of differences in physical properties of the mineral matter and coal. Some of those physical properties include size, density and wettability [2].

Dense Medium Vessels are notable devices for the separation of coarser coal particles with size greater than 12.5mm (Figure 2.15). These devices contain large open tank through which a dense suspension for pulverized coal is moved. Coal particles start suspending in the surface of the vessel because of its low density and subsequently these particles are transported with the help of overflow to collection screen. The waste sinks to the bottom where it is collected using flights, which are mechanical scrapers [2].



15**Figure 2.15: Dense Medium Vessels**

The washed coal is, then, transported through drain-and-rinse (D&R) screens for removal of magnetite medium from the surface of the coal and dewatering of the coal particles. In case of the presence of magnetite, as inorganic material associated with coal particles, it is, generally, recovered and used in magnetic separators [2].

Likewise, Dense Medium Cyclones (DMCs) are intendedly used for coal particles which are in the size range of 0.5 to 12.5 mm. These are high capacity devices and work on the same basic principle as Dense Medium Vessels (Figure 2.16) [2].

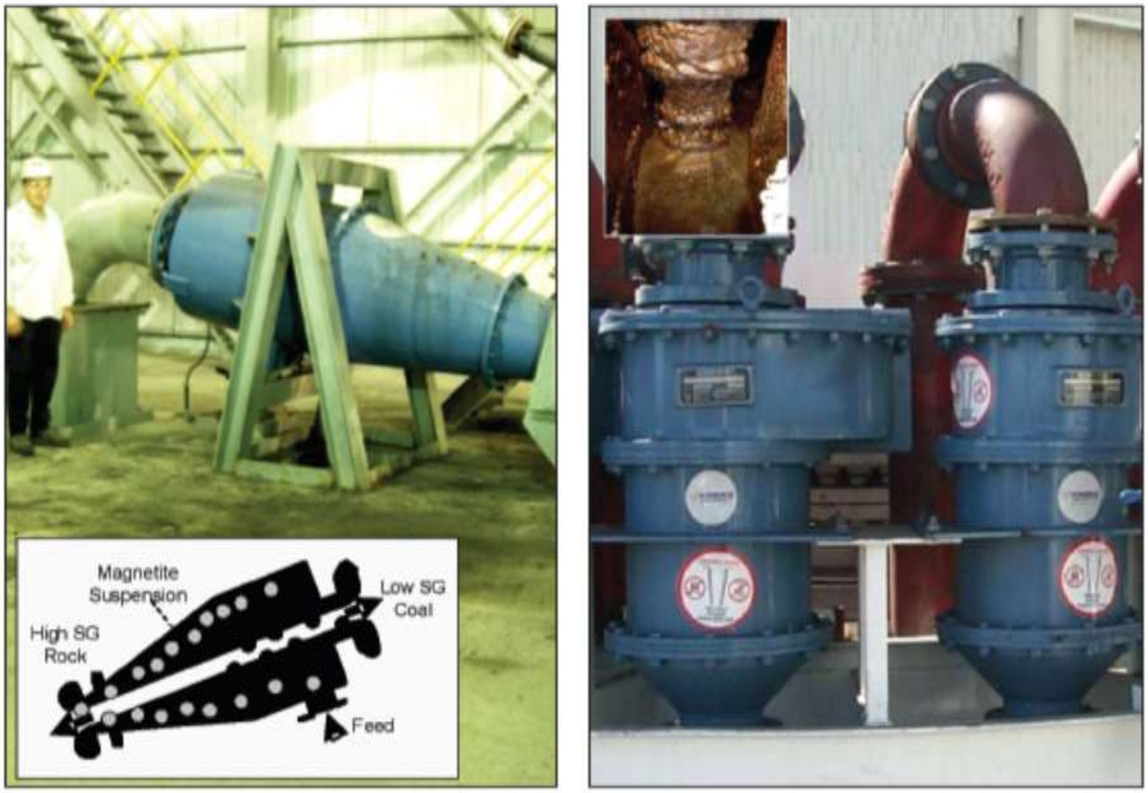


Figure 2.16: Dense Medium Cyclones

Water Based Density Separators: For separation of coal and rock particles in the range between 0.2 and 1.0mm, density based separators are used and the most common of these are water-only cyclones and spirals [2].

Water-only cyclone has broad wide angles conical bottom and basically a classifying cyclone. The formation of dense suspension forms by natural fines, which are already in feed slurry.

On the other hand, the presence of corkscrew shaped device on spirals helps in sorting the coal from rock with the help of selective segregation. Spirals are arranged in groups because of their low unit capacity and sometimes water-only cyclones and spirals are employed in combination (Figure 2.17) [2].

17Figure 2.17: Spirals

For the treatment of very fine coal particles, froth flotation is quite promising approach which works on the basis of difference in the surface wettability of coal and rock particles (Figure 2.18). During the process, air is passed through a pulp containing coal and mineral particles and coal particles selectively get associated with air bubbles and move to surface. The mineral particles tend to stay in suspension because of their tendency for wettability. Sometimes, a frother, is also added which helps in promotion of small bubbles. Likewise, a collector is also added which promote the adhesion between air bubbles and coal particles. On the basis of chemical nature, collectors are generally hydrocarbon liquids such as diesel oil or fuel oil [2].

Figure 2.18: Conventional Froth Flotation Unit

Solid-Liquid Separations: Solid liquid separations are carried out for the removal of undesirable surface moisture, which result in reduction of calorific value and handling problems. Additionally, the transportation cost also increases [2].

Simple screens have capacity for removing water from the surface of coal, however, for removal of water content from fine particles, centrifugal methods or filtrations systems are employed [2].

In centrifugal dewatering systems, centrifugal force manages to pull water away from the surfaces of coal particles (Figure 2.19). Likewise, for fine particle with size less than 1 mm, screen-bowl centrifuge is used (Figure 2.20). These processes are quite capable of producing products with low moisture, though, with the use of bulk water, sometimes ultrafine solids are lost [2].

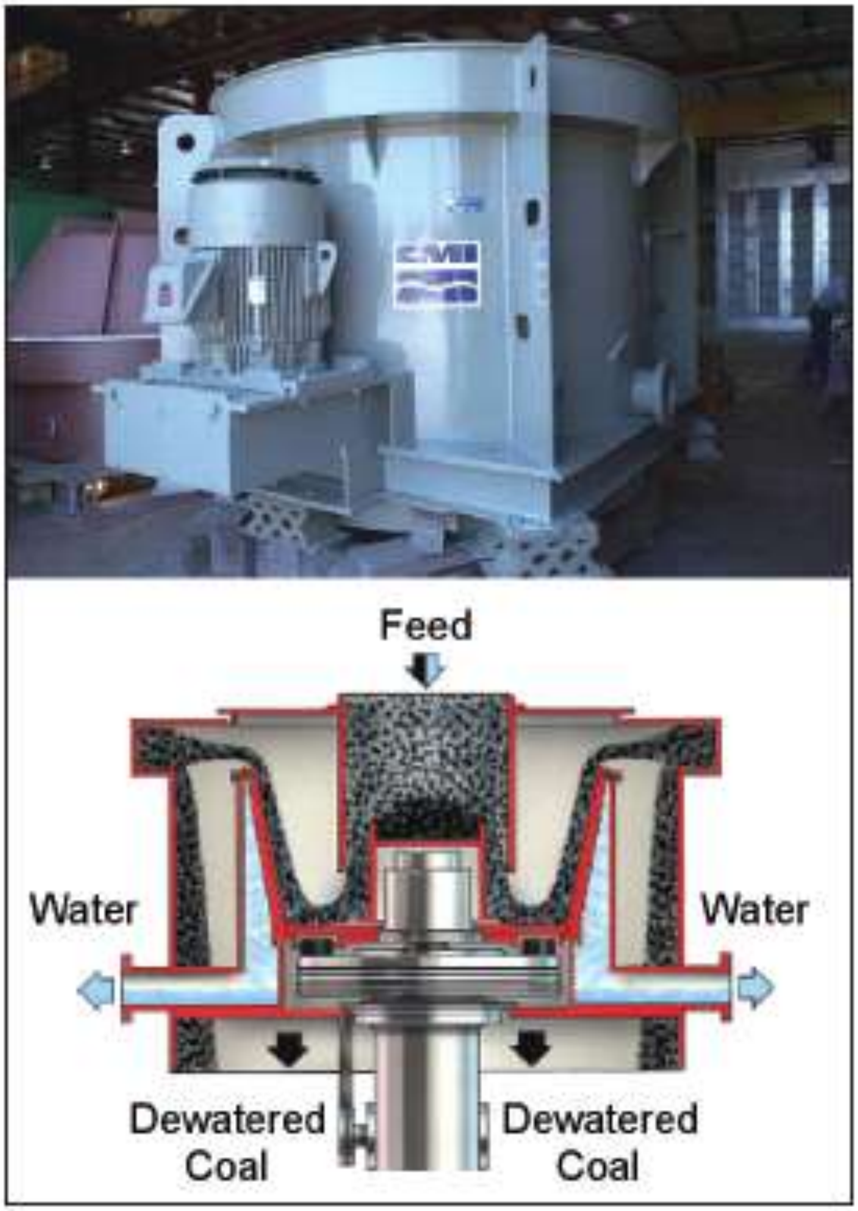


Figure 2.19: Vibratory Centrifugal Dryer

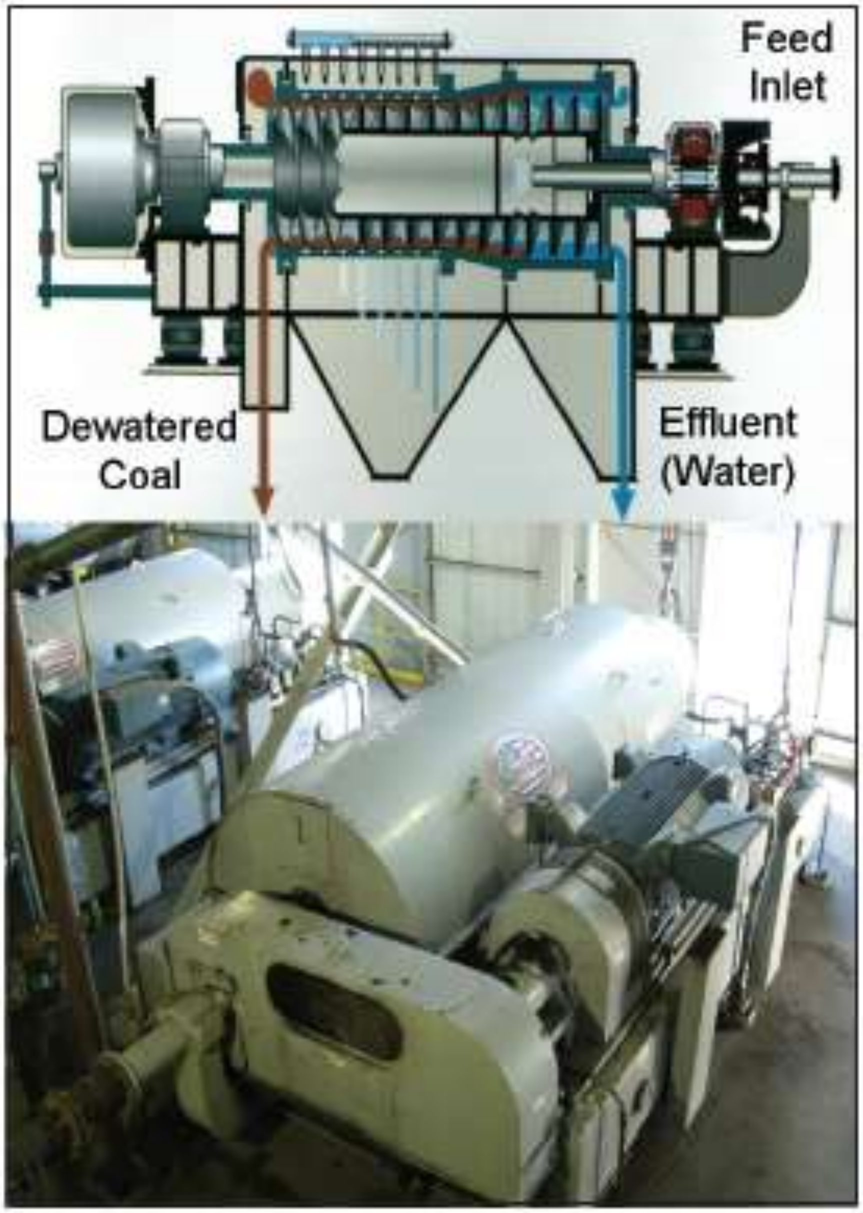


Figure 2.20: Screen Bowl Centrifuge

Filtration Dewatering: Filtration is one of the most basic unit operations employed for high recovery of coal from dewatering. The basic operative mechanism behind filtration is the entrapment of fine solids as a cake against porous medium (filtering). Vacuum filtration is also used for the dewatering of flotation concentrates in order to achieve high coal recovery i.e., more than 97% with the production of water up to 20-30%. Disc filter is among the most employed vacuum filters (Figure 2.21). Moisture content can also be reduced using thermal dryers. The most common and popular design operative across the globe is fluidized bed dryer (Figure 2.21). However, high capital cost is associated with thermal dryers and these can pose emission problems related to poor capacity and fugitive dust [2].

Figure 2.21: Disc Vacuum Filter (On Left Side) and Thermal Dryer (On Right Side)

Clarification and Thickening: For treating the process water, thickening is the most basic unit operation for recycling and reuse of the water within the plant (Figure 2.21). Large tank in the thickener collects the particles for settling leading to the formation of clarified overflow and thickened underflow. Finally, the sludge from thickener is moved to disposal facility or it is dewatered further as per requirement. Sometimes, the use of chemical, such coagulants, is also managed in order to promote enhanced settling [2].

Waste handling and disposal happens to be the last step of a coal preparation plant and it involves the permanent storage and handling of waste using a number of approaches. As waste originating from coal fines is difficult to dewater, generally, these are discarded in terms of slurry, containing coal fines, clay, slit or any other minerals which are finely divided. The disposal of slurry is made into an impoundment, which is basically an infrastructure based on settling basin, often, behind a manmade dam (Figure 2.22). The volume of the impoundment must be sufficiently enough to hold larger amounts of waste from thickener [2].

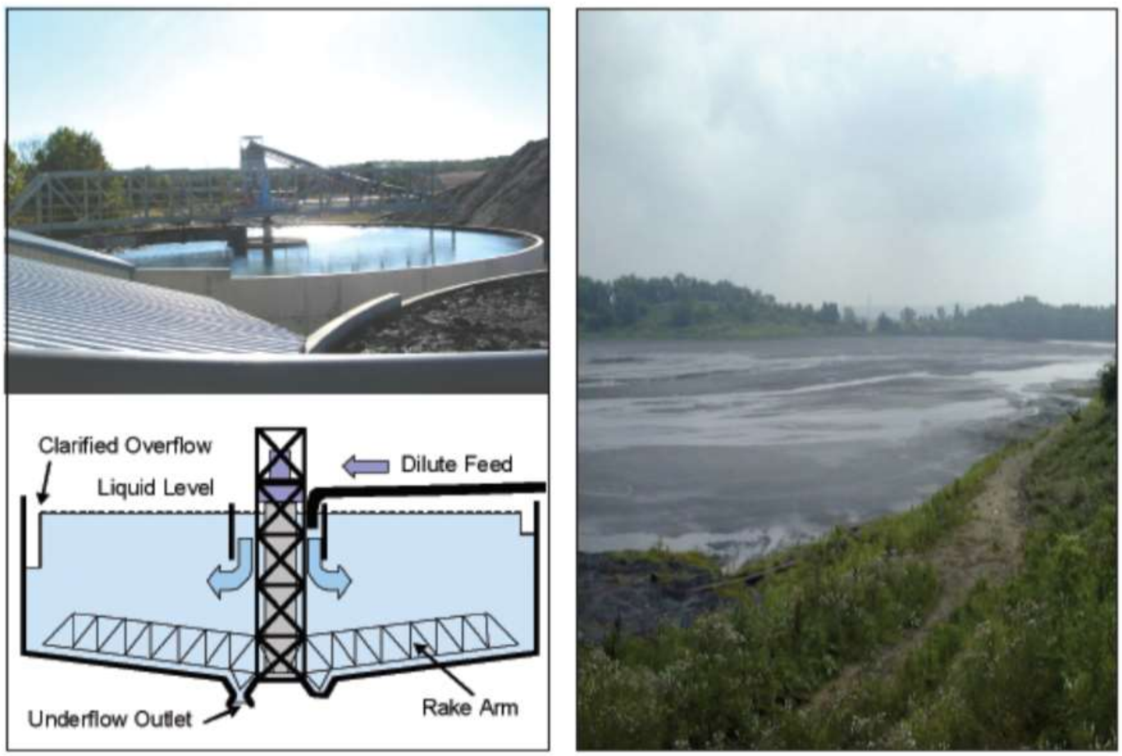


Figure 2.22: Conventional Thickener (On Left Side) and Active Slurry Impoundment (On Right Side)

2.6.2 Clean Coal Technologies during combustion

During combustion of coal, in addition of the efforts to increase thermal efficiency, two key technologies are employed for SOx and NOx control. During combustion, SOx reduction is achieved in fluidized bed combustion system with induction of lime in the fluidized bed. This configuration reduced the SOx emissions by 90%.

2.6.2.1 SOx Reduction during Fluidized Bed Combustion

When fluidization medium (limestone, sand etc.) placed on the distribution panel (perforated panel) is supplied with air from beneath, the medium floats in the air current within a specific range of the air speed, just as in a state of boiling. The layer of floating medium in this state is referred to as a fluidized bed. When coarsely-crushed coal is continuously supplied into the fluidization medium, which is heated in the air heating furnace to. the ignition temperature of coal, the coal spontaneously starts burning. The furnace is turned off at this point, and while the coal keeps burning, coal supply volume is controlled so that the temperature of the fluidized bed stays at 760 to 860 deg.C. For recovering heat, the fluidized bed combustion boiler has heat exchanger tubes in its fluidized bed and convection section. The use of limestone as fluidization medium enables in-furnace desulfurization. Flue gas from the fluidized bed combustion boiler includes various unburned components, which are collected by the mechanical precipitator and burned in the after-burner furnace (CBC) to improve combustion efficiency.

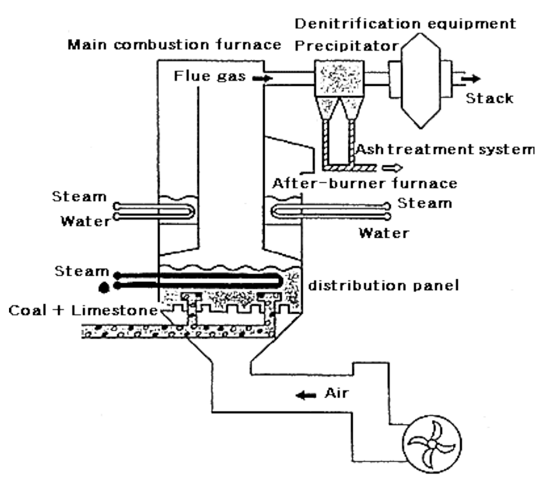


Figure 2.23: Typical Fluidized Bed Boiler with limestone injection

Various aspects of limestone utilization have been investigated in detail by various researchers. [3, 4] The cost of addressing SOx emissions using limestone dozing in fluidized bed combustion is cheaper than flue gas scrubbing.

2.6.2.2 NOx reduction during Pulverized Coal Combustion

Low NOx Burners: The design of low NOx burners helps in controlling the fuel and air mixing for creating larger and branched flames. This results in the reduction of peak flame temperature and less NO_x are formed. Burner efficiency also improves because of improved flame structure. Likewise, three stage NO_x reduction processes, fuel staged burners, selective catalytic reduction processes are employed for achieving significant reduction in NOx emissions [5].

Low NOx burners (LNBs) are designed to control fuel and air mixing at each burner in order to minimize NOx formation. Peak flame temperature is often reduced, which results in less NOx formation. The improved flame structure in LNBs compared to conventional burners reduces the amount of oxygen available in the hottest part of the flame thus improving burner efficiency. In a conventional low NOx burner, combustion, reduction and burnout are achieved in three stages within the burner. In the initial stage, combustion takes place in a fuel-rich, oxygen-deficient zone where NOx is formed. A reducing atmosphere follows where hydrocarbons are formed and react with the already formed NOx. In the third stage, internal air staging completes the combustion but may result in additional NOx formation [5].

Selective Catalytic Reduction: Selective catalytic reduction is specifically employed for targeting NOx in flue gas streams for converting it into N_2. A gaseous reluctant, typically, ammonia is employed. This technology is one of the most promising, proven and effective for NOx removal, originating from coal fired power plants [6].

SCR technology has been in commercial operation in Japan since 1980 and in Europe since 1986 on power stations burning low-sulphur coal (~0.5–1.5%). There is now approximately 182 GWe of coal-fired capacity fitted with SCR throughout the world and a further 72 GWe capacity currently under construction or planned to be fitted with SCR [7]. Since the early 1990s, SCR system are currently in operation in Austria, Belgium, Canada, China, Denmark, Finland, Germany, Italy, Japan, Korea, Sweden, Taiwan and the USA. They are also currently under construction and/or planned in France, Ireland, Netherlands, Portugal and the UK [8].

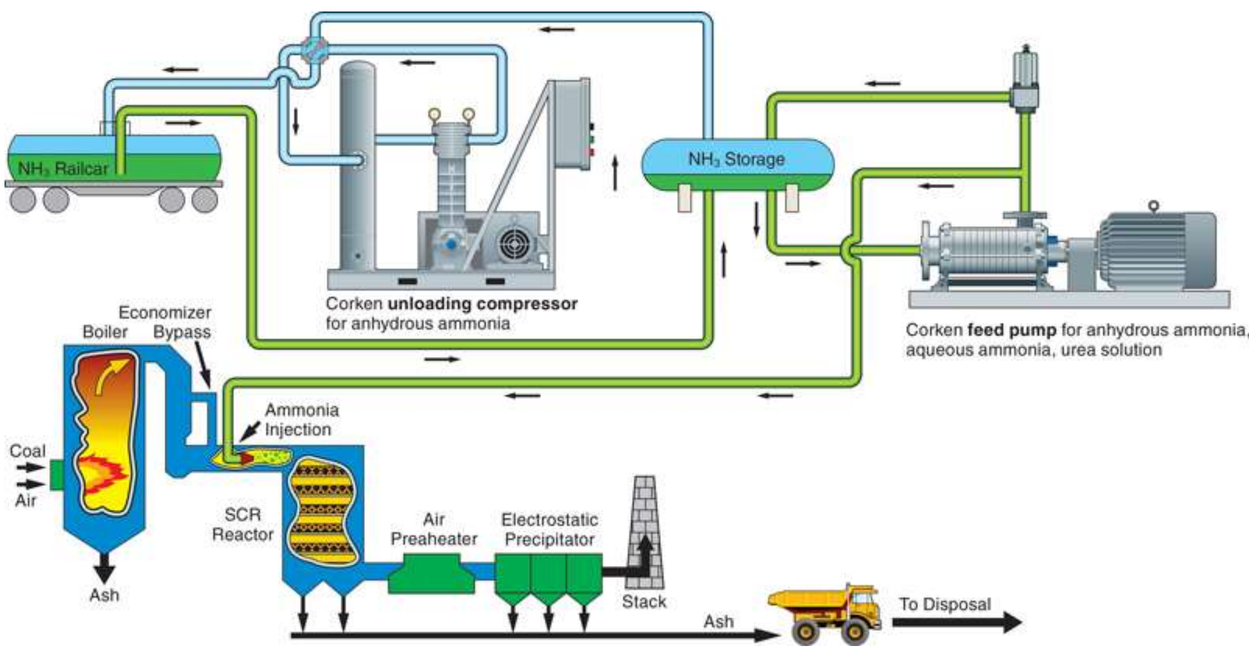


Figure 2.24: Selective Catalytic Reduction

In SCR systems, vaporized ammonia is generally used as a reducing agent. The ammonia is injected into the flue gas stream, passing over a catalyst. NOx emission reductions of more than 80–90% are achieved. The optimum temperature is usually between 300–400°C. This temperature is normally the flue gas temperature at the outlet of the economizer during high load operation. In some cases, it may be necessary to install an economizer bypass to increase the flue gas temperature to these levels at the economizer outlet. A SCR system consists of reagent storage and vaporization, reagent injection, reactor, catalyst, soot blowers, and control instrumentation. The NO_x and ammonia react to form nitrogen and water as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

Selective Non-Catalytic Reduction (SNCR): This technology was mainly employed in Japan by oil-based power plants in the 1970s. Europe started using SNCR on coal fired power plants since the end of 1980s while US deployed these facilities in early 1990s [9]. Today, plants, with exceeding capacity of 20GWe, are making use of SNCR technology for controlling reduction in NO_x emissions [10]. The operative mechanism behind this technology is the injection of gaseous ammonia or urea into hot flue gas, which tends to convert NOx into nitrogen and water vapors as per following reactions;

$NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$

or

$NO + 2CO(NH_2)_2 + O_2 \rightarrow 4N_2 + 2CO_2 + 4H_2O$

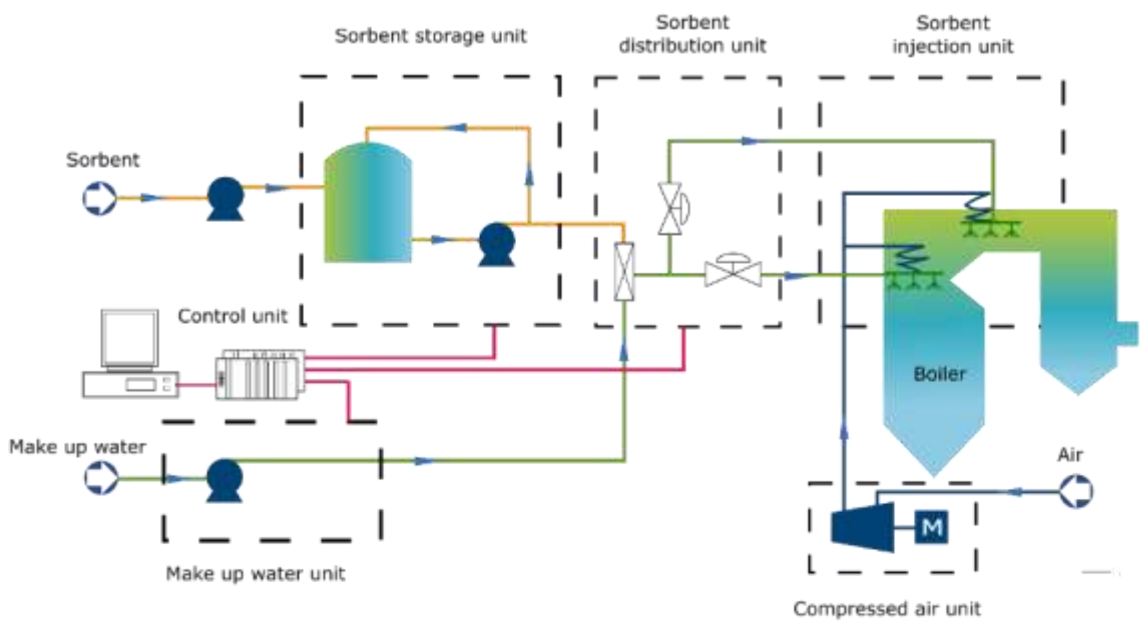


Figure 2.25: Selective Non-Catalytic Reduction

No catalyst is required in the SNCR technology. The performance of a SNCR system depends on factors specific to each application including flue gas temperature, available residence time for the reagent and flue gas to mix and react, the amount of reagent injected, reagent distribution, NO_x levels as well as CO and O_2 concentrations in the flue gas [11].

Fuel Staging: Fuel staging can be achieved in a number of ways. One approach involves a procedure which shuts off the flow of fuel from one burner or more in order to make the flow of rich fuel, leading to NOx emission control. Generally, such technique is not used in pulverized coal fired power plants [12].

The second approach is known as fuel biasing, which involves the diversion of fuel from the upper level of burner to lower level or to the centre. Besides this, the diversion can also take place from the central part of burner to the side burners. The whole idea behind this approach is to establish a fuel rich central or lower zone for achieving complete burnout. In this technology, lower flame temperatures are achieved and it also improves the balance of concentration of oxygen within the furnace. It has been estimated that almost 30% reduction in NOx emissions has been achieved. Currently, this technique is being employed in 13 pulverized coal based power plants [12].

Similarly, another form of fuel staging is reburning, which can be considered as a three-stage (zone) system, which is, sometimes, also known as three stage combustion process. This include actually three zones, which are primary combustion zone, reburn zone and burnout zone [12].

2.6.2.3 Co-Combustion

The application of co-combustion has not only provided a way to utilize abundant biomass and waste together but also an alternative to fossil fuels. Coal-fired boilers are being switched to co-combustion though, a great deal of difficulties is being faced during this transformation and particularly in developing countries the nature of such problems still needs to be investigated, like in India [13-17].

Power generation based on coal-biomass co-combustion is gaining interests on larger scale because one of the components of this compendium is a source of renewable energy, i.e., biomass. It is also considered to be neutral in terms of carbon. The implications of co-combustion and co-gasification, involving coal and a variety of biomasses can play significant role in the partial replacement of coal. On the other hand, the use of biomass for co-combustion also offers a cost effective, renewable, secured and sustainable solution to environmental issues posed by the massive use of coal. Consequently, not only the reduction in emissions of CO_2, SO_x and NO_x can be achieved but also the releases of gases like methane, ammonia, hydrogen sulphide, organic acids, mercaptans, amides and other chemicals can be controlled and a number of researchers has reported the advantages associated to co-combustion [13-20]. Instead of developing dedicated waste or biomass fired power plants, the supplementary use of the biomasses as fuel increases utility of these as fuels, particularly with highly efficient coal utilizing power plants. Additionally, the retrofitting is quite cost effective, thus, eliminating the need of building sole new power plant for co-combustion [18, 21-27]. Carbon neutrality is one of the most important advantage associated with the use of biomasses as they tend to absorb the same amount of CO_2 during their life cycle as they emit CO_2 after combustion. In term of chemical characterization, they are much different compared to the coal because of high volatile matter, oxygen and moisture contents and low nitrogen and sulphur contents [28, 29].

2.6.3 Post Combustion Clean Coal Technologies

2.6.3.1 Carbon Capture and Storage

With the dawn of industrial age, anthropogenic activities have increased carbon dioxide (CO_2) levels in atmosphere and the effects of these developments are well documented [30-32]. Coal utilization is one of the major sources of anthropogenic carbon dioxide emissions and international efforts are underway to limit its share. However, growing population and better life quality will result in increased energy consumption and coal is going to play a major role in furnishing ever-increasing energy demand in near to midterm future [33, 34]. Carbon capture and sequestration (CCS) technologies offer significant reduction of carbon dioxide emissions from coal based power generation [35]. However, key challenges in the application of CCS are capital cost, transport and storage of such large quantities of carbon dioxide [36]. There are a number of options available for the application of CCS to coal fired facilities, however, three technologies including amine solvents, Oxyfuel combustion and calcium looping are mature enough for industrial applications in near future [37].

Carbon dioxide capture through amine solutions is a relatively mature technology [38]. Briefly, CO_2 is brought in contact with amine solutions in the absorber unit yielding water-soluble salts through a reversible reaction. The regenerator unit separates clean CO_2 gas from the amine solutions making them available for reuse. This process is suitable for CO_2

capture from dilute low pressure flue gas. Ease of application makes this technology suitable for retrofitting in existing coal fired power plants [39].

This technology is essentially and end of pipe operation making it suitable for retrofit or in construction of new plants. However, the application of this technology will increase both capital and operational costs resulting in net efficiency drop from 45 to 35% [40, 41]. The reduction of efficiency is due to solvent regeneration, CO_2 compression and transportation. Low partial pressure of CO_2 in the flue gas requires higher quantities of amine solutions. CO_2 compression costs are also increased in this process owing to low degradation temperatures of amines.

Significant improvement in application of amine solution technology only be expected from advancements in amine solution materials as the process itself is a mature technology and widely applied [42, 43]. Monoethanolamine (MEA) is considered be the best available option for application in CCS and other developments are benchmarked against MEA performance. Sterically hindered compounds are also under consideration and promising results have been demonstrated [44, 45]. Another important aspect in the application of amine solutions for CO_2 capture is the emission of solvent in atmosphere which are reported to be harmful for human health [46].

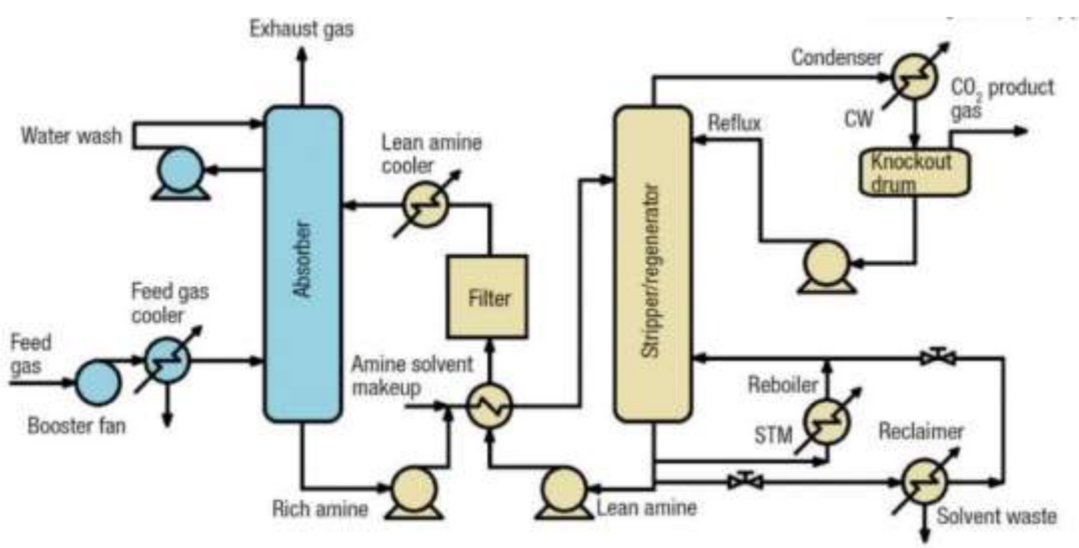


Figure 2.26: Amine Solution based CO2 Separation and Regeneration

Chemical looping technology makes use of the reversible reaction between CO_2 and calcium oxide (CaO) yielding calcium carbonate ($CaCO_3$) which is subsequently calcined to release pure CO_2 as shown in figure. Fluidized Bed reactors are frequently applied as both carbonator and calcinatory vessels. Carbonation is an exothermic reaction being carried out 650 °C. However, conversion of CaO to $CaCO_3$ is markedly decreased after repeated cycles of CaO carbonation [47] On the other hand, calcination is an endothermic process and mainly applied at 900-950°C resulting in increased cost of heating.

$$CaO_{(s)} + CO_{2(g)} \rightleftharpoons CaCO_{3(s)}$$

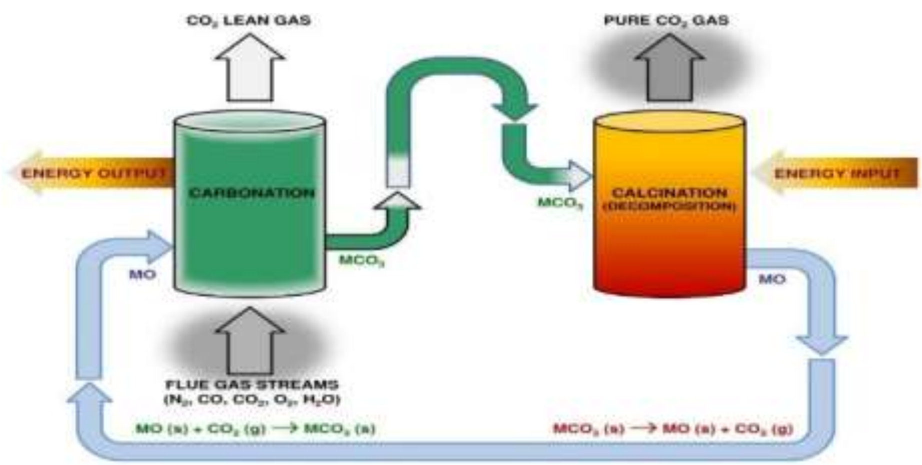


Figure 2.27: Chemical Looping Technology

Energy losses in this process are relatively smaller owing to thermodynamic advantages. However, CaO tends to lose its reactivity with CO_2 after repeated cycles. This problem is a subject of extensive research and development [48].

Oxyfuel combustion presents another viable option for separating CO_2 flue gas. Coal is burned in O_2 and CO_2 thereby producing flue gas primarily containing CO_2 and H_2O, which can be easily removed through condensation leaving pure CO_2 for compression process [49]. However, separating O_2 from air presents a significant cost and makes efficiency penalty similar to amine solution technology. Oxyfuel combustion boost a major advantage in terms of elimination of thermal NO_x and suppression of fuel NO_x. Similarly, SOx generation is also suppressed as SO_2 tends to retain in fly ash under Oxyfuel combustion conditions [50].

Depleted oil/gas reserves, deep coal seams and saline aquifers are the major options available for CO_2 sequestration.

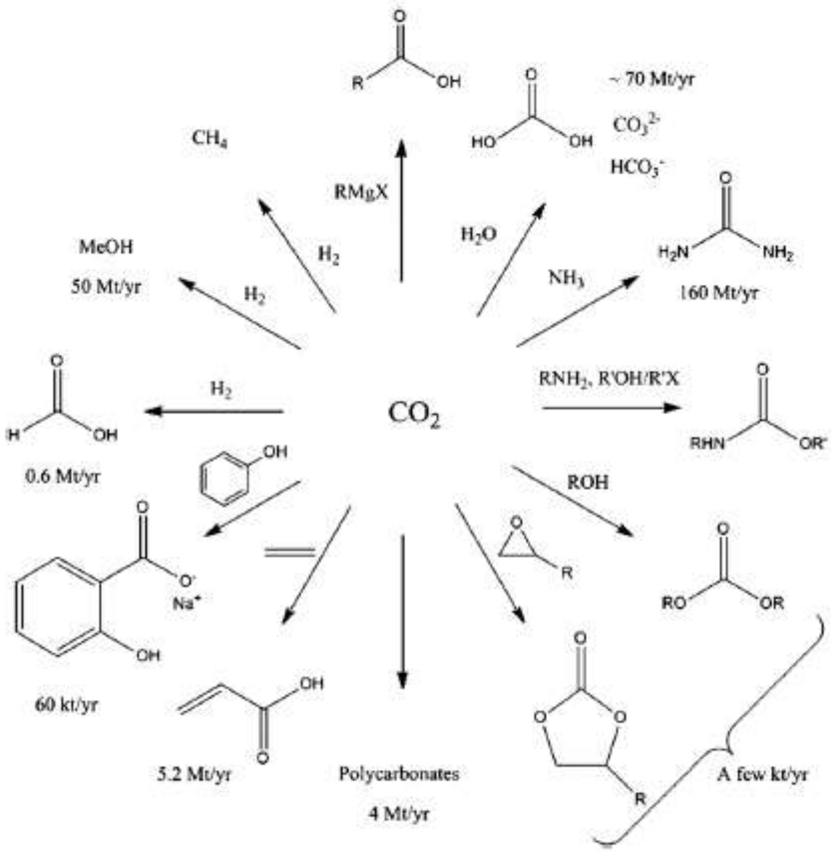


Figure 2.28: CO2 as Chemical Feedstock

2.6.3.2 Flue Gas Desulfurization

Post combustion coal cleaning, commonly known as Flue Gas Desulphurization, is compendium of techniques which are meant for capturing SO_2 from flue or stack gases. The basic chemistry of technology involves the reaction of SO_2 with an alkaline reagent to produce a neutralized solid, as SO_2 is acidic nature [51].

SO_2 is well known eye, throat and nose irritant, which cause respiratory illness. Additionally, emissions of SO_2 into environment also leads to acid rain. Generally, SO_2 emissions can be controlled using two approaches, involving 1) selection of fuels with lower sulphur content 2) Deploying technologies for SO_2 removal from flue gas stream. A variety of techniques are available which can remove efficiently SO_2 from flue gas stream, including Wet Flue Gas Desulphurization (FGD), dry FGD, circulating dry scrubber and dry sorbent injection [52].

Flue gas enters the absorber and travels up through the absorption zone where it contacts the absorbent slurry or solution that is passing counter-currently down through the absorber. The scrubbed gas continues upward through a mist eliminator that traps entrained absorbent drops before the flue gas exits the scrubber. The scrubber solution falls into a recycle tank in the bottom of the absorber and is pumped to a nozzle header above the absorption zone. A bleed stream is pumped to a disposal or slurry dewatering system (Figure 3.1).

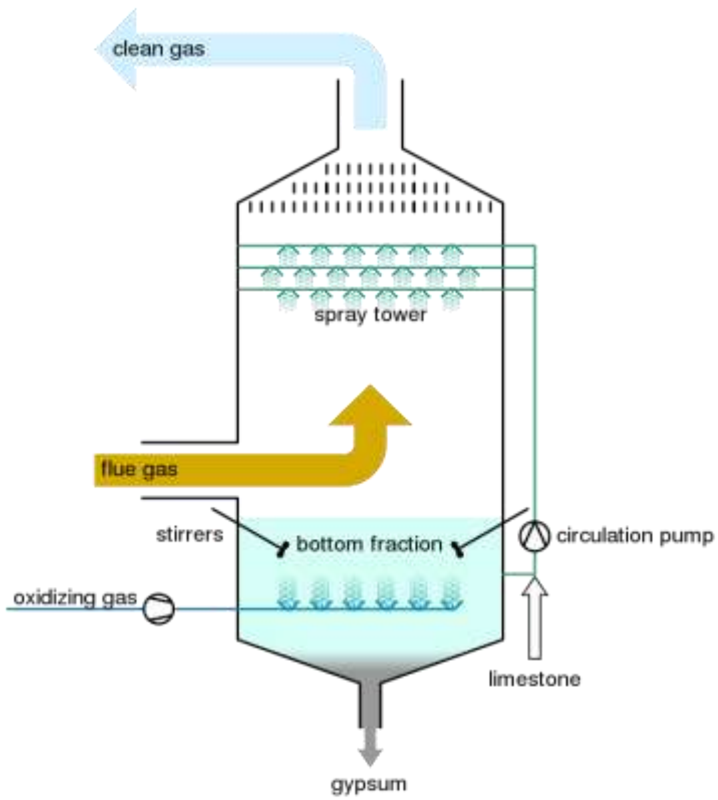


Figure 2.29: Typical Wet FGD System

Wet FGD is the predominate technology used worldwide for the control of SO_2 from utility power plants. Limestone is commonly used as the reagent for wet FGD. For most high sulfur applications, a limestone wet FGD has an overall lower cost than other processes for SO_2 removal. However, wet FGD systems can be designed for a variety of reagents including lime, magnesium-enriched lime, seawater and soda ash. Limestone-based systems can also use an organic acid additive to enhance SO_2 removal [52].

Dry FGD, is an alternative to wet FGD for SO_2 control on utility boilers. The process is also called semi-dry to distinguish it from injection of a dry solid reagent into the flue gas. An SDA is an example of this type of FGD system. In an SDA system, lime slurry (typical), is atomized and sprayed into the hot flue gas to absorb the SO_2 and other acid gases. The resulting dry material, which includes reaction products and fly ash, is collected in a downstream particulate control device, typically a fabric filter or sometimes an ESP [52].

2.6.2.4 Particulate Matter Control:

Electrostatic precipitator are used for controlling particulate matter emissions into the environment. It is a device which is dedicatedly used for the separation of particles from gas stream while imposing minimum loss of the pressure of the stream. Likewise, fabric filters are also being used for the removal of particulate matter from flue gas stream. Mercury in some chemical forms is very toxic. If it finds its way into water sources, it can be converted into water soluble species, such as methyl-mercury, by microorganisms and accumulate in the fatty tissue of fish. Consumption of contaminated fish is the main risk to humans[52]. Powdered activated carbon (PAC) injected into the flue gas is the most established technology for mercury control, and can provide up to approximately 95% mercury capture for coals with high chorine content [53]. By adsorbing onto the surface of the PAC, the elemental, oxidized mercury and particulate mercury are removed in particulate control devices (ESP or fabric filter) [52]. Chemical modification of the PAC, such as halogenation, can improve the ability to capture mercury, but can also increase material costs. PAC is carbon that has been treated with high temperature steam using a proprietary process to create large surface area [52]. Each PAC particle consists of a carbon skeleton with numerous branching pores that provide a very high surface area-to-volume ratio. Pollutants, such as mercury, become adsorbed in the nanopores of the PAC particles, and are effectively removed from the flue gas stream. The sorbent activity varies with respect to each chemical species, with oxidized mercury having a greater rate of adsorption by PAC than elemental mercury [52].

Chapter 3: Status and Potential of Clean Coal Technologies in SAARC Member States

3.1 Afghanistan:

Afghanistan is blessed with 66 million tonnes of coal reserves. However, this resource may expand with further exploration and evaluation. Currently, with insignificant annual production of coal in Afghansitan, predominantly, underground coal mining is being practised. Coal is either being produced by labour-intensive mining using dog holes or through inefficient underground mining with inadequate facilities, which are hand driven, with no roof support [54]. Morerover, there is no coal fired power generation facility is installaed in Afghanistan. The use of coal is mainly limited to domestic heating and brick kilns.

Afghanistan Demand-Supply Situation

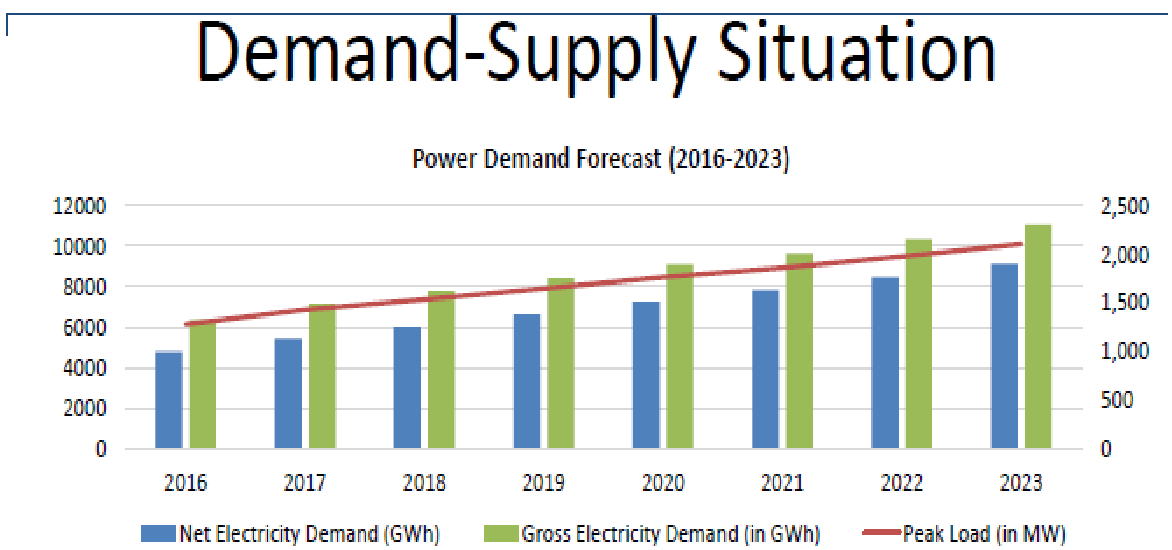


Figure 3.1: Projected Power Demand in Afghanistan

However, power requirement in Afghanistan will continue to increase in near future and will reach to 2200 MW. In the planned energy mix of Afghanistan's government, about 4000 MW coal based power generation potential has been identified. [55] This is an excellent opportunity to develop HELE coal fired power plants. Moreover, since coal mines in Afghanistan are range as deep as 1000-1400 meters, there is potential of carbon capture and storage. CO_2 can be stored in abandoned coal mines in three states: free in empty spaces, adsorbed on the remaining coal or dissolved in mine water. Deep formation of these coal mines may become an important sink for the storage of CO_2 released from proposed coal fired power plants.

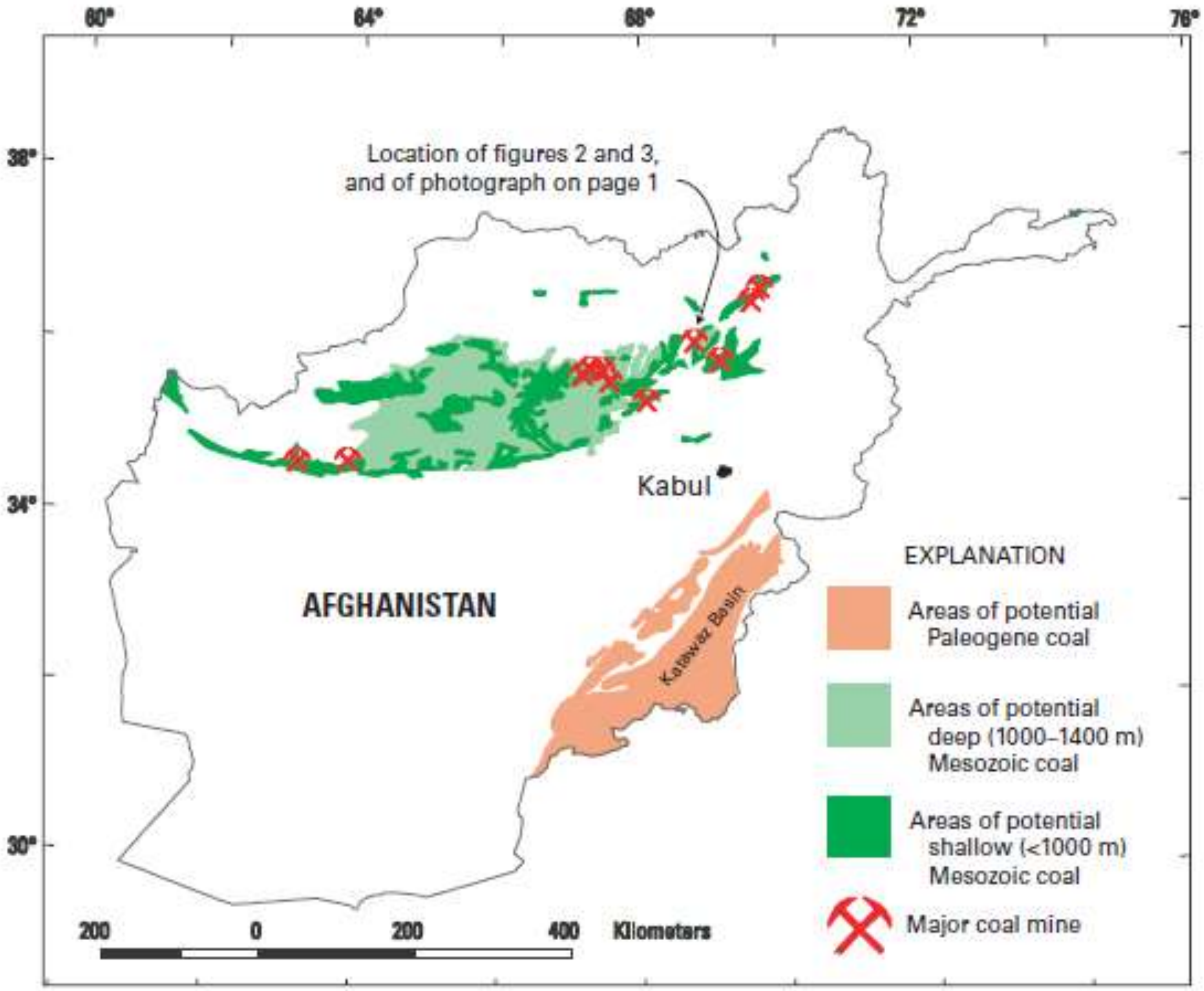


Figure 3.2: Distribution of major coal-bearing rocks in Afghanistan.

3.2 Bangladesh:

In Bangladesh, presently, underground mining is the only method, which is being practised for the extraction of coal from Barapukuria Coal Mine [56]. This mine is mechanized with adequated advanced facilities and equipment for the extraction of coal.

Currently, the share of coal in electricity generation is not more than 2.5%, however, 19 coal fired power plants have been planned with electricity generation capacity of 19,650 MW (11250 MW on domestic coal and 8400 MW on imported coal) through 100% super-critical coal based power generation by 2030. One of the proposed coal power plants, Matarbari HELE coal plant, is supposed to achieve the thermal efficiency of 42% [57].

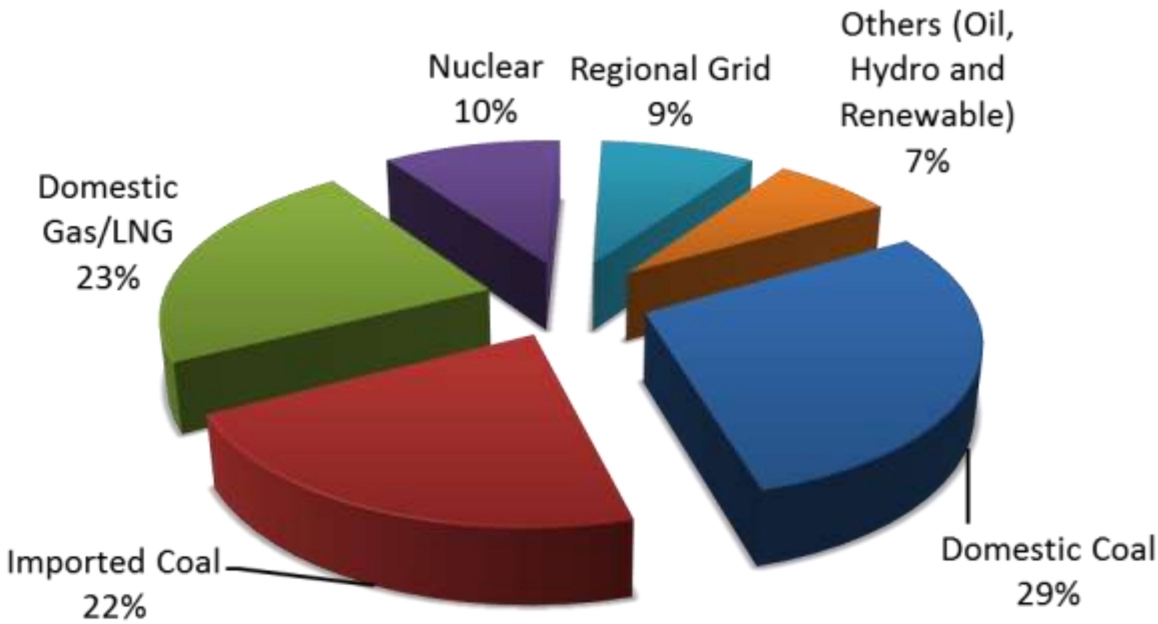


Figure 3.3: Probable Power Generation of Bangladesh Primary Fuel Sources by 2030

Government of Bangladesh has also planned to provide to every household by 2021 which means that total power generation capacity will become 24,000 MW. Coal fired power generation is all set to take off in Bangladesh with several projects are in various stages of development amounting to 4600 MW capacity.

Since the proposed coal fired power plants will be employing super-critical technology, the efficiency of these plants will be higher than other coal fired power plants installed in the region for instance in India. However, there is massive potential of CO_2 storage in spent gas fields across the country.[58] Fourteen of the gas fields have estimated CO2 storage capacities >10 Mt. Two have estimated CO2 storage capacities >200 Mt. Given that Bangladesh's emissions from large point sources are approximately 11 Mt year-1, the storage capacity in gas fields alone appears adequate for some time to come.

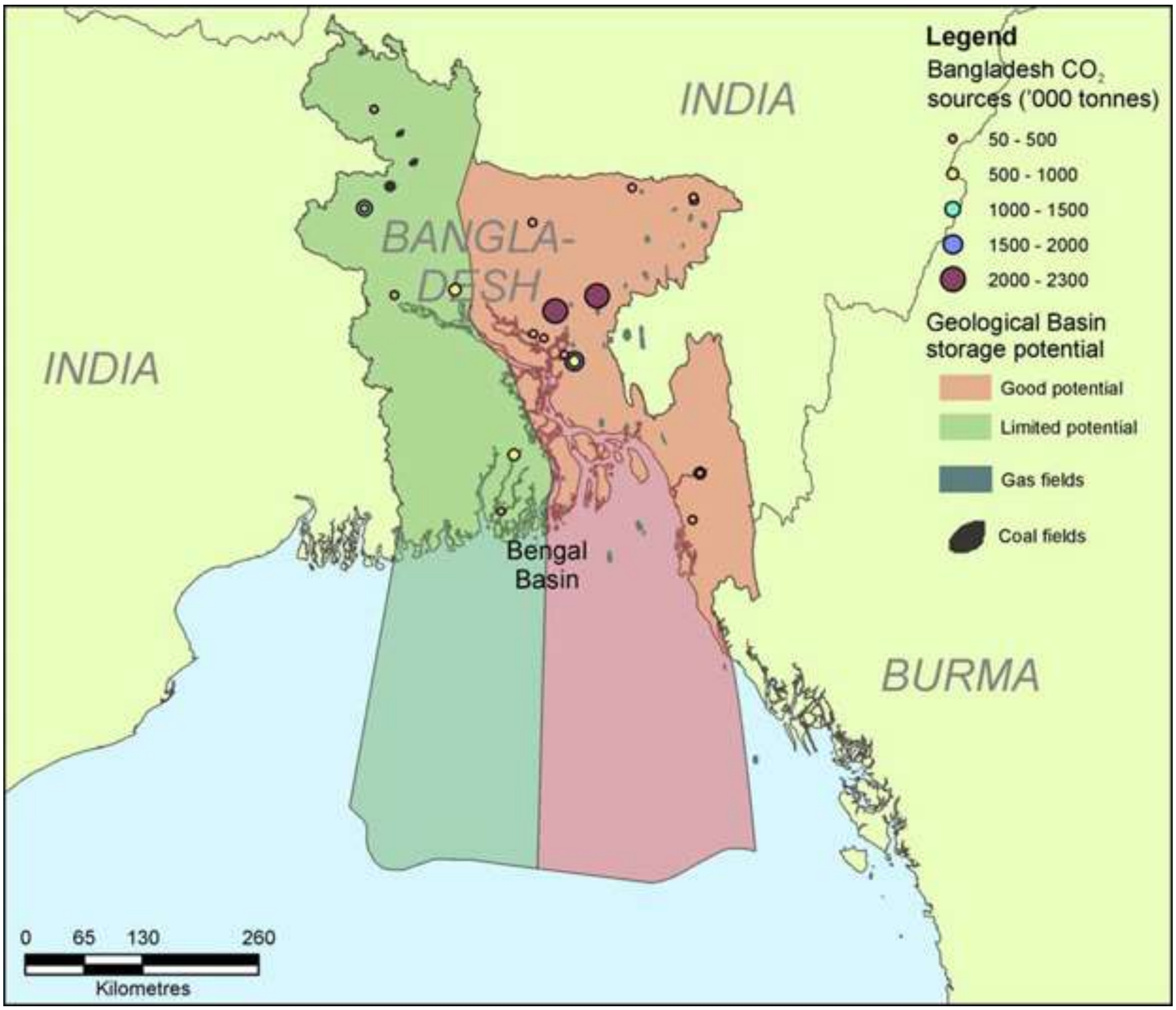


Figure 3.4: CO2 Storage Potential in Bangladesh

Bangladesh has three concealed coalfields: Jamalganj, Khalaspir and Barapukuria (Holloway & Baily 1995). All are in the NW of the country, west of the Jamuna River (Figure 4.1). The only field that has been exploited to date is Barapukuria, which is being mined at present. Additionally, coal has been discovered in a borehole at Dighipara, at a depth of about 2398 m. Coal is also present at depth in the Kutchma X-1 and Singra-1 oil exploration wells (at and below 2714 m and below 3080 m respectively). There is also some near-surface coal in the extreme NW of the country, near Phulbari in Dinajpur district. This is likely to be too shallow to be able to adsorb significant amounts of CO_2, even if it was not required as an energy resource. The Jamalganj coalfield was discovered in the early 1960s and is known from 11 boreholes. It is thought to occupy an area of about 37 km^2 (Rahman & Zaher 1980). The coal is at depths of approximately 640-1100 m and occurs in the Raniganj Coal Formation, of Permian age. Up to 7 seams are present and there is significant variation in seam thickness: seam 3 varies between 4.63 and 27.32 m thick. Rank is high volatile bituminous B. Ash content is about 22-25%. Reserves are estimated to be between 1,053 million tonnes and 1563 million tonnes (Rahman & Zaher 1980). Key factors relevant to its CO_2 storage potential, such as coal permeability and its gas storage potential, are unknown. The core from the Jamalganj coalfield was stored in Quetta (at the time in West Pakistan) prior to Bangladesh's independence and has now been lost. No isotherms are available.

Assuming the Jamalganj coalfield could be used for CO_2 storage, and the coal seams were sufficiently permeable, and an average of 0.02 tonnes CO_2 (Appendix 1) could be stored per tonne of coal, its CO_2 storage capacity is estimated to be between approximately 20 and 31 Mt CO_2. The Khalaspir coalfield was discovered in 1989. The coal-bearing area is approximately 12.26 km^2 (Nazrul Islam et al. 1991). Within this area, Gondwana coals are present at depths of 257-481 m below surface. Up to 8 coal zones, consisting of coals interbedded with carbonaceous mudstone and sandstone, are present. Up to 6 seams are present in each zone, seams range in thickness from 0.6 to 15 m (Landis et al. 1990). Mean ash content is 21.8%. Rank is high volatile bituminous A to low volatile bituminous. Estimated proven reserves are 143 million tonnes, estimated proven plus probable reserves are 685 million tonnes. Assuming the Khalaspir coalfield could be used for CO_2 storage, and the coal seams were sufficiently permeable, and an average of X tonnes CO_2 could be stored per tonne of coal, its CO_2 storage capacity is estimated to be between 3 and 14 million tonnes.

The Barapukuria coalfield is being mined. Even if the thinner seams are not mined, they will effectively be exposed to surface pressure conditions and will not have the potential to adsorb significant amounts of CO_2. The Barapukuria coalfield therefore has no CO_2 storage potential.

Gas content analysis of the Barapukuria coal showed that it contained negligible amounts of methane (Norman 1992). The Dighipara coal discovery is only known from one borehole. Its top is at a depth of 328 m. Seam 1, the shallowest seam is 27 m thick in the Dighipara borehole. A second seam, unbottomed but at least 12 m thick, occurs from 348 – 360 m. Gas content analysis shows that it contains negligible amounts of methane. The coalfield is thought likely to be too small and too shallow to store significant amounts of CO2.

The greater part of Bangladesh lies in the eastern part of the Bengal Basin (Figure 4.1). In the north of the country there is a buried basement ridge known as the Rangpur Saddle that runs between the Shillong Plateau and The Rajmahal traps (both in India). The Bengal basin becomes progressively more folded to the east and eventually merges into the Assam-Arakan fold belt, which occurs in the Chittagong Hill tracts of eastern Bangladesh. The CO2 storage potential of the Bengal Basin and Assam-Arakan Fold Belt is described in Appendix 3. The eastern, folded half of the Bengal basin in eastern Bangladesh has excellent CO2 storage potential in the many anticlines that are found there. There is also likely to be large potential in the Chittagong Hill Tracts, although this region is remote from many large point sources and may suffer from overpessure, at least locally. The western half of Bangladesh, west of the Jamuna River suffers from a lack of structural closures suitable for containing geologically stored CO2, and so may have less storage potential.

With the above-mentioned capacity of CO_2 storage in place for Bangladesh, the need of the hour is to incorporate the CCS with coal fired power plant planning. The additional funding may be sought from Green Climate Fund to offset the additional costs. Moreover, coal fired power plants that are being planned on imported coal may be placed in the vicinity of emptied gas fields to facilitate the storage of CO_2.

3.3 Bhutan:

There are 1.96 million tonnes of coal reserves in Bhutan, geologically distributed in the areas of Deothang, Bangtar - S/Jhongkhar and Dzongkhag [59]. According to International Energy Statistics (EIA), total primary coal production in year 2012 was approximately 0.1 million tonnes, (Figure 1.5) [60]. Total coal consumption in year 2012 has been 0.033 million tonnes and it is mainly used for domestic purposes [61]. Since the production and consumption of coal is limited in Bhutan, there is limited room for inception of clean coal technologies.

3.4 India:

In India, as per estimates of Central Electricity Authority, Ministry of Power, Government of India, almost 61% of the generated electricity comes from coal as of June 30, 2016. In terms of technology, India had almost 50GW capacity of sub-critical based power generation and more than 150GW capacity of super-critical based power generation (Figure 2.32). In terms of sectoral use of coal, almost 3/4th of coal is consumed in power generation (Figure 2.33). Rest of the coal share contributes majorly to steel & washery, cement, paper, textiles.

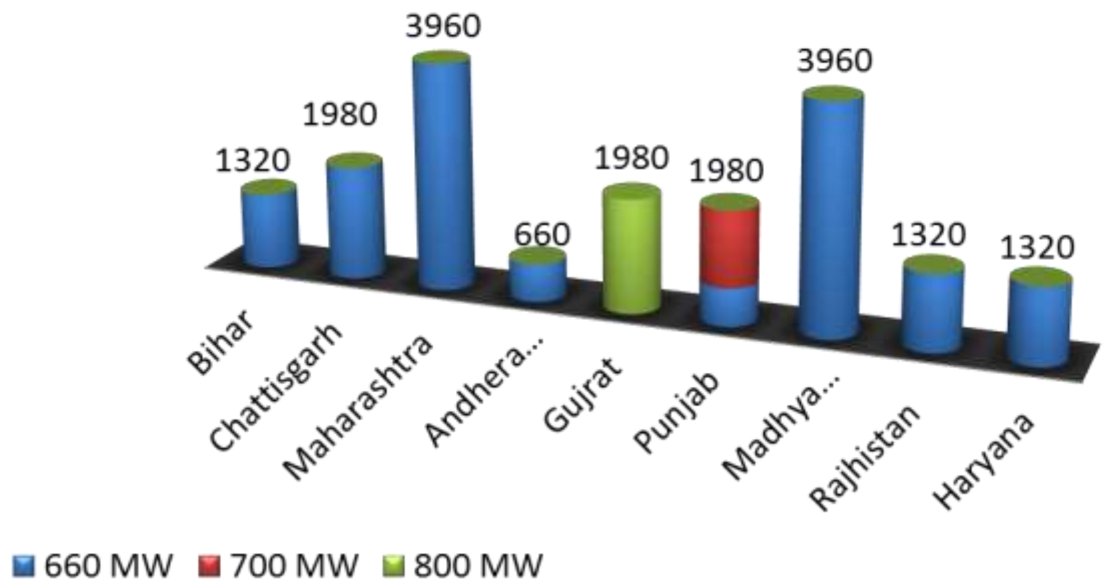


Figure 3.5: State-Wise Existing Supercritical Coal based Power Generation Capacity in India (MW)

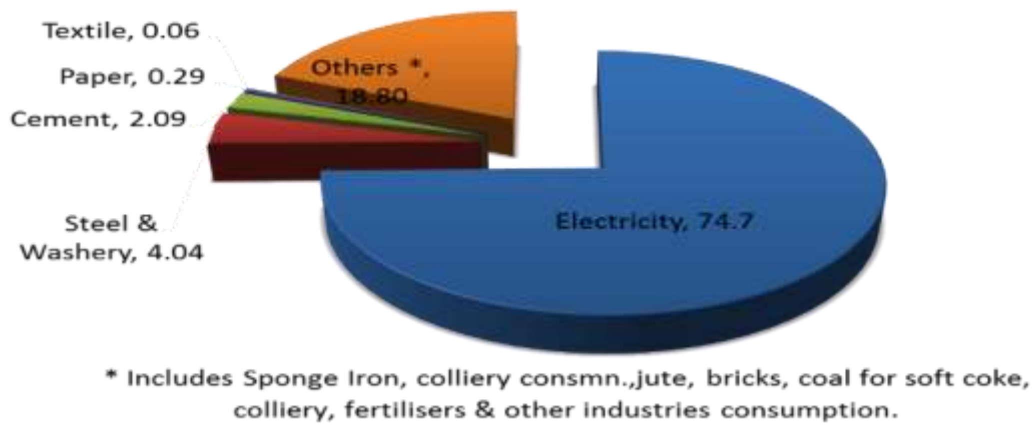


Figure 3.6: Sectoral Consumption of Coal in India for Year 2013-14

Coal sector in India is largely governed by Coal India Ltd. (CIL) which is fundamentally responsible for the production of indigenous coal, however, CIL has not been able to meet its coal production challenges in the 11th Five Year Plan and coal production is not guaranteed for the upcoming coal based power generation plants. As a matter of policy, CIL is directed to involve private sector to ensure that it meets the targets of 795 million tonnes of coal production by the end of 12th plan [62]. Only 25% of this increase in generation capacity will come from captive coal mining and the rest has to be furnished by CIL. Therefore, the need of the hour is to involve private sector for coal mining ventures. Nationalization of coal sector is under scrutiny since the 11th plan and the involvement of the private sector might be incorporated to address the limitations of indigenous coal production. On the contrary, coal based power generation has significant involvement of private sector as given by Figure 4.4.

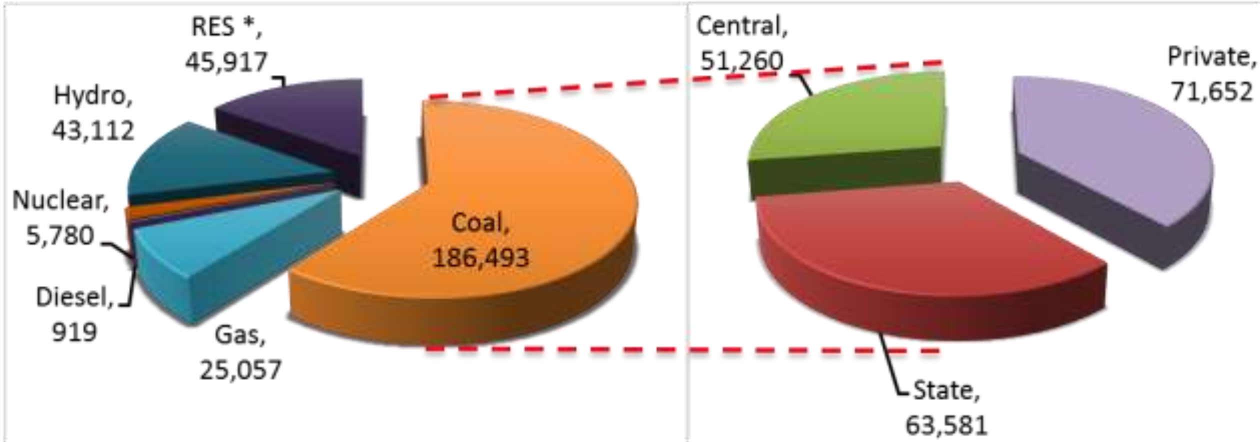


Figure 3.7: Total Installed Power Generation Capacity of India, Share of State & Central Governments and Private Sector in Coal based Power Generation

*** RES include SHP, BP, U&I, Solar and Wind Energy. Installed capacity in respect of RES (MNRE) as on 30.09.2016 (Ministry of Power, Government of India)**

It is obvious that coal encompasses more than 60% of power generation in India. Private sector provides 38.4% of the coal based power generation capacity. This contribution will only be going to enhance with the inception of ultra-mega projects.

3.4.1 Potential geological CO2 storage sites in India

The potential geological CO2 storage sites in India considered in detail in this report are divided into three categories:

- Oil and gas fields
- Coal seams
- Saline water-bearing reservoir rocks

The potential for storage in basalt rock formations is not quantified as this storage concept is not considered to be mature at present (IPCC 2005). However, it is noted that two extremely large areas in India are covered by thick basalt formations, the largest of which is known as the Deccan Traps and the smaller as the Rajmahal Traps. If the concept of CO2 storage in basalt formations can be advanced into a mature option, it may have great potential in India (Singh et al. 2006).

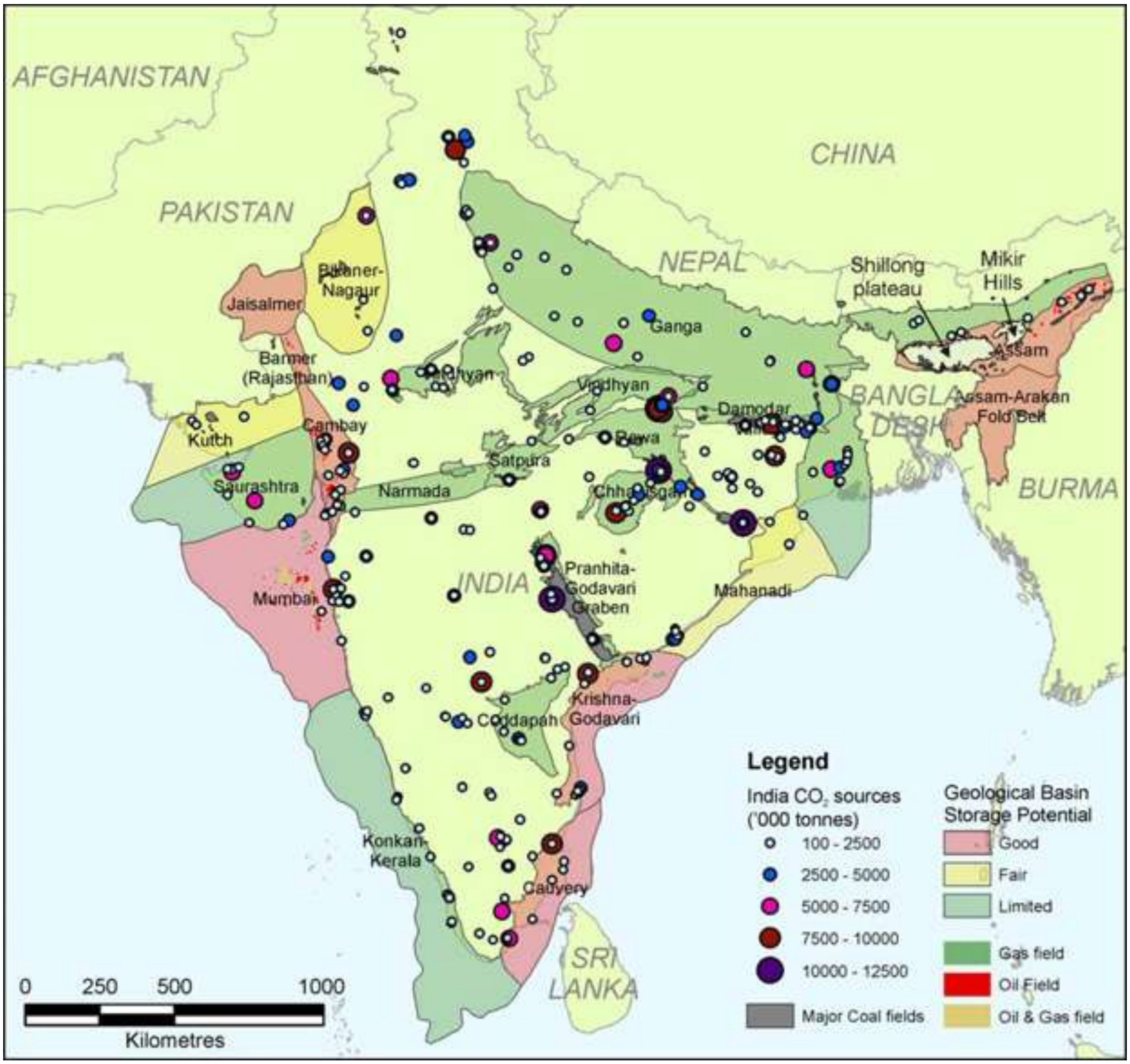


Figure 3.8: Major current CO2 sources and potential CO2 storage sites in India.

The location of oil and gas fields in India is shown in figure 4.4. They occur in three areas: Assam and the Assam-Arakan Fold Belt (NE India), the Krishna-Godavari and Cauvery Basins (SE Indian coast), and the Mumbai/Cambay/Barmer/Jaisalmer basin area (NW India. Based on this assumption, the storage capacity of the oil fields of India is estimated to be 1.0 to 1.1 Gt CO_2, approximately one year's emissions from major point sources. The storage capacity of the gas fields and gas caps on oil fields is estimated to be 2.7 to 3.5 Gt CO_2.

A key issue for India's CO_2 storage capacity in coal seams is to what extent mining will take place in each coalfield. It is considered likely that open cast mining and selective underground mining to 600m depth will take place in all major fields irrespective of coal quality, reserve position and distribution pattern, even in basins with only power grade coal. Selective underground mining of superior grade non-coking coal and coking coal is likely to take place down to 1200m in the Jharia, Raniganj, Bokaro, Karanpura and Sohagpur coalfields. Selective underground mining is likely to lead to the development of fissures and fractures in the overburden above mined seams, and may also enhance the permeability of the Coal Measures below the mined seam. Thus the only areas where CO_2 storage is actually likely to be practical in India are areas of the major coalfields either not subject to selective underground mining or significantly (say 100 m) below mined seams.

Bachu et al. (2007) state that: "Permeability is a determining factor in the viability of a CO2 storage site, and currently it is considered that coal permeability has to be greater than 1 mD for successful CO2 injection and/or coalbed methane (CBM) production. Coal permeability is affected by physical (mechanical) and chemical factors. It varies widely and generally decreases with increasing depth as a result of cleat closure with increasing effective stress. The permeability of shallow coals (a few hundred metres deep) is on the order of millidarcies (mD) and higher, while the permeability of deep coals is on the order of microdarcies (µD), which is too low to allow CO2 injection and flow without fracturing. Coalbed methane cannot be produced if permeability is less than 1 mD (Zuber et al., 1996), and this is generally reached in the depth range 1300-1500 m. It is for this reason that most of the coalbed methane producing wells in the world are less than 1000 m deep (IPCC, 2005), and why 1300-1500 m is considered as the depth limit of possible CO2 storage in coals. Coal is a polymer-like substance that is often affected by the gas with which it is in contact.

There is estimated to be limited storage potential in India's coalfields (345 Mt CO2), oil fields (1.0 to 1.1 Gt CO2) and gas fields (2.7 to 3.5 Gt CO2). Even if all this capacity were to be deployed it would make little impression on future emissions from large point sources, which were about 721 Mt CO2 in 2005-6.

The average efficiency of India's coal-fired power fleet is relatively low compared with other large energy users such as China and the United States. The two underlying causes of this are the quality of coal used and the technical specifications of the generation fleet. Improvements in both areas could produce substantial improvements in efficiency and total output, while reducing carbon and particulate emissions per unit of electricity. Figure 15 illustrates the effect of different technologies on an 800megawatt power station operating at a capacity factor (actual output relative to potential output) of 80 per cent and generating 6 TWh a year.

The efficiency of a power plant is also affected by the temperature difference between the internal heat source and the external environment. India's high ambient temperatures and relative humidity are not consistent with achieving some of the efficiencies achieved in cooler climates such as in Europe. Coal-fired power plants in India tend to perform better in winter than in summer (IEA 2014b). Finally, around 90 per cent of India's coal-fired fleet utilises subcritical technologies that have substantially lower efficiency rates than the supercritical and ultra-supercritical technologies that have been developed and deployed in various countries (see Appendix Part B for more detail on these technologies). Moreover, much of India's older generators are smaller units with efficiency well below 30 per cent (IEA 2014b).

3.5 Maldives

Maldives is meeting its energy demands from imported furnace oil and will continue the same trend in future as well. Therefore, utilization of coal is not planned.

3.6 Nepal

As per estimates of Nepal Electricity Authority for year 2013, total installed capacity for electricity generation in the country is almost 782 MW out of which the requirements for 733 MW (~94%) are met by hydropower [63]. For year 2011-12, the share of coal was 3.93% in terms of energy consumption by fuel type, which might be increased for indigenous production of electricity. Nepal is also importing and purchasing electricity from India and Independent Power Producers (IPP) and for available data of year 2014, half of the electricity generated was contributed from import and purchase, which was 2331.17GWh, where total electricity generation was 4631.51GWh [63]. Coal fired power generation is currently not in operation in Nepal and it is unlikely to start owing to lower costs of hydropower.

3.7 Pakistan

According to Power Generation Policy 2015, Present Government intends to develop system for providing efficient and consumer oriented power generation, however, ever worsening energy crisis of Pakistan is still in place. Main objectives of current power generation policy are [64];

1. Provision of sufficient power generation capacity at lower cost
2. Encouragement and surety of exploitation of indigenous resources
3. Monitoring of the processes by all stakeholders
4. Safeguarding of the environment

According to BP Statistical Review 2016, Pakistan is heavily dependent on natural gas for meeting energy demands (approximately 50%) [65]. Though, Pakistan has been blessed with massive coal reserves, however, the total share of coal in energy mix is not more than 10%. Pakistan has been unable to tap these resources efficiently for power generation on national scale, however, present Government is trying to develop coal sector. Additionally, there are numerous industries, particularly, textile, sugar, steel and cement, which are involved in captive power generation, however, the data pertaining to actual use of coal in captive power generation neither has been compiled nor documented, yet. According to Integrated Energy Plan 2009-2022, 24 mills, including textiles and sugar, are connected and supplying power, while 17 have made contracts for power production [66].

Energy Expert Group has also proposed Integrated Energy Plan 2009-2022, which revealed heavy reliance of Pakistan on import of hydrocarbons would cost Pakistan USD 41 billion in 2022, which is at the moment around USD 12 billion, thus an increase of 241% in import bill. Likewise, electricity generation capacity needs to be increased from 15000MW to 50000MW by 2020. Such targets can only be met by introducing diverse energy mix with logical share of each energy resource. The report emphasized on increasing of share of coal up to 10000MW by 2020 through public and private partnership [66].

Pakistan is planning to generate 11,880 MW coal fired power under China-Pakistan Economic Corridor (CPEC) projects. Approximately, 36 million tonnes of imported coal will be consumed for 7 projects (Table 3.1) [67]. However, the remaining projects are planned on Thar coal field, once the field will be ready for coal production.

Table 3.1: Upcoming Coal Fired Projects under CPEC Programme

Project	Capacity (MW)
Port Qasim Electric Company Coal Fired, 2x660, Sindh	1320
Sahiwal 2x660MW Coal-fired Power Plant, Punjab	1320
Engro thar 4x330MW Coal-fired, Thar, Sindh	1320
HUBCO coal power plant 1X660 MW, Hub Balochistan	660
Rahimyar Khan Coal Power Project, Punjab	1320
SSRL 2×660 MW Mine Mouth Power Plant,Sindh	1320
HUBCO coal power plant 1X660 MW, Hub Balochistan	660
Thar mine mouth oracle, Thar Sindh	1320
Muzaffargarh Coal Power Project, Punjab	1320
Gaddani Power Park Project (2×660MW)	1320
Total Installation Capacity	**11880**

In the proposed power plants given in the table 3.1, the plants based on Thar coal will be operating at subcritical steam conditions which accounts for nearly 33 % of upcoming installation capacity. This is a potential area of improvement. Since Thar coal reserve is lignitic in nature, it has real potential for the application of Integrated Gasification Combine Cycle Technology. At policy level, Government must seek financial support from Green Climate Fund to offset the higher installation costs. The increase in thermal efficiency will significantly reduce CO_2 emissions per kWh.

Another important advantage going through the route of IGCC is the relative higher concentrations of CO_2 in the flue gasses. This CO2 after may be linked with already established natural gas network.

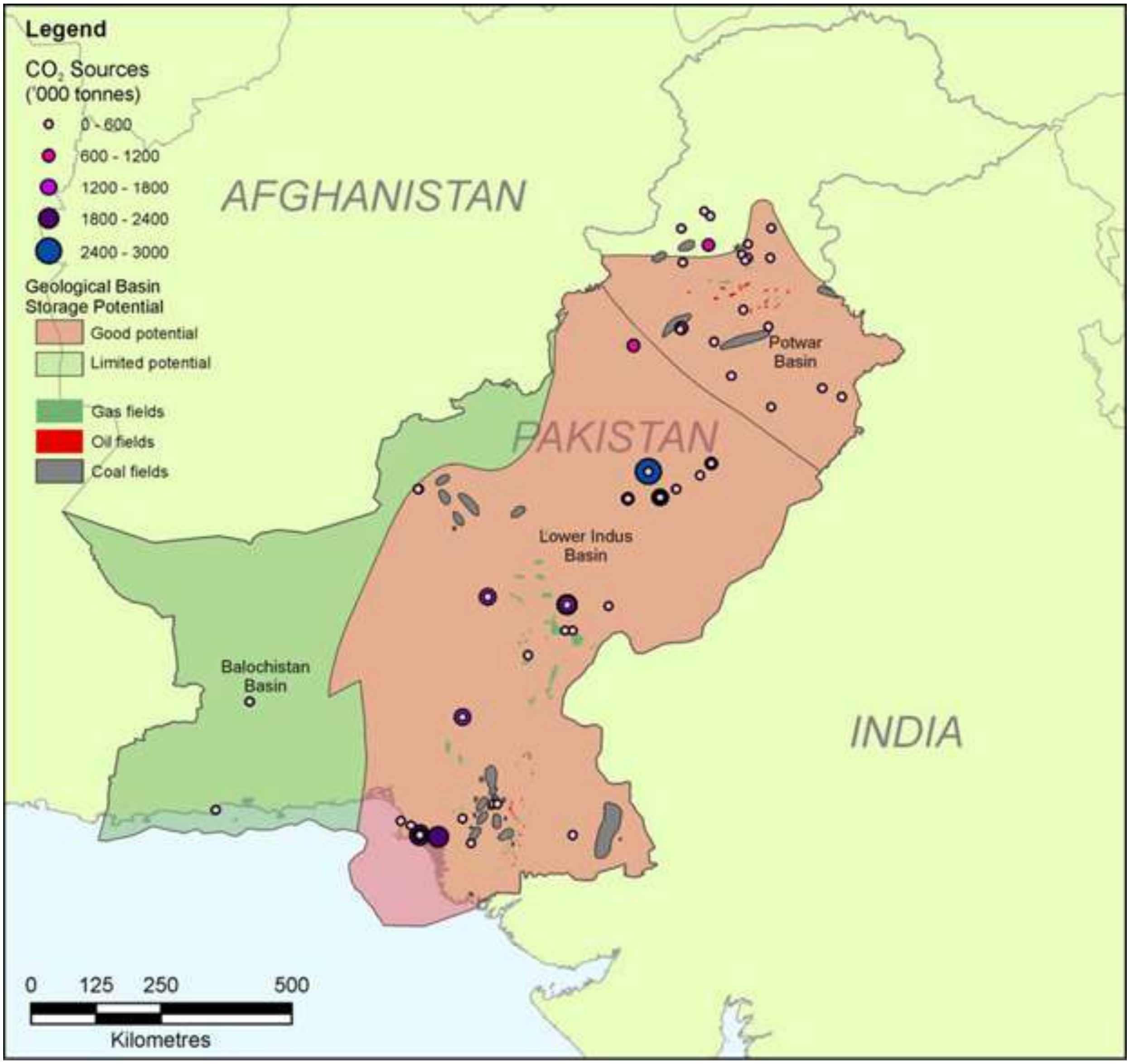


Figure 3.9: Major current CO2 sources and potential CO2 storage sites in Pakistan.

Pakistan has significant CO_2 storage potential (1.7 Gt CO_2) in its gas fields when they become depleted. Four gas fields (the Sui, Mari, Qadirpur and Uch fields) are estimated to have the potential to store >200 Mt CO_2. Moreover, Pakistan has good potential for saline aquifer CO_2 storage in the Lower Indus and Potwar Basins. There is little storage potential in Pakistan's coalfields and oil fields - none of the oil fields are thought to have a storage capacity of 10 Mt or more. Nevertheless, it is clear that Pakistan is well placed to exploit CCS technology. All the major CO_2 sources are close to potential gas field storage sites or above sedimentary basins with good saline aquifer CO_2 storage potential.

3.8 Sri Lanka

There are minor coal resources in Sri Lanka, though, the recent surge of introducing imported coal for power generation is highlighting the need of coal for power generation. According to Sri Lanka Energy Balance (compiled by Sri Lanka Sustainable Energy Authority), 1.61 million tonnes of coal was imported in year 2014 [68].

Sri Lanka has minor coal reserves; however, coal is being imported for meeting the requirements of industries and power generation. Total coal consumption stood at approximately 1.46 million tonnes [61]. Majority of coal is being used in power sector i.e. 1.36 million tonnes [61].

In Sri Lanka, currently, one coal based power plant (sub-critical) at Lakhvijaya is operational with capacity of 900 MW and one is under-construction at Sampur, which has the capacity of 500 MW.

Sri Lanka relies heavily on import of oil and in order to avoid power shortages, present Government adopted coal-based power generation. However, environmentalists have raised concerns over coal based power generation and country might not be able to persuade coal based power generation anymore. As per estimates of Energy Outlook for Asia and the Pacific 2035, primary energy demands of the country will increase up to 20.3Mtoe in 2035 from 9.9Mtoe in 2010 [69].

As per Sri Lanka Sustainable Energy Authority, Government foresees for achieving the target of 100% electrification of every corner of the country [68]. Such targets, pertaining to increasing energy generation capacities, can be achieved through the implementation of appropriate technologies in economically viable fashion. However, present scenario may not comply with the conditions fulfilling the prerequisites described above. According to the formulations of Ministry of Power and Energy (M/P & E), entitled as *National Energy Policies* *and Strategies of Sri Lanka-2008*, the need of a diverse energy mix, with gradual increase of non-conventional renewable energy, is the key to complete electrification of the country [70].

According to the proposed plan by Ministry of Power and Energy, the share of coal was supposed to be increased from 20% to 54% for electricity generation, thus proposing, more than half of electricity generation coming from coal. However, as per Ceylon Electricity Board estimates, 42.45% of electricity was generated on August 16, 2016 through coal [71]. Coal based power generation comes from Norochchole, LakWijaya Coal Power Project, nevertheless, another Coal based Power Project (Sampoor Coal Power Plant; 2×250 MW) is expected to be completed by the end of 2017, which is expected to have 500 MW capacity of electricity generation [69].

Recommendations

1. Based upon the available energy resources in the region, coal will play a major role in uplifting the region from poverty. Therefore, policies must encourage the deployment of clean coal technologies to ensure sustainable development.
2. Sub-critical coal fired power plants in the region, particularly in India needs to be retrofitted with supercritical or ultra-supercritical technologies along with emissions control technologies including flue gas desulfurization units, low NOx burners and electrostatic precipitators.
3. Indian and Pakistani coals of lignite rank are best suited for integrated gasification combined cycle technology. Dedicated gasification systems must be deployed to install IGCC systems. Higher capital costs of IGCC may be offset by tax reductions, low interest loans and seeking support from Green Climate Fund.
4. Pakistan's consumed gas fields present an excellent opportunity to deploy CCS technology. At policy level, it must be made mandatory to integrate CCS with newly establishing power plants to maintain low emission profile of the country.
5. Regional efforts must be made to deploy large scale CCS projects which can store CO2 generated from Indian coal fired power plants in Pakistan to utilize the storage potential of the region.

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