1. Overview

This brief overview on steam power plants focuses on conventional pulverized coal fired power plants (PCF PP). While the steam cycle section of the power plant is similar for power plants operated on all fuels, the fuel handling, combustion and post-combustion environmental control systems are substantially more complex in PCF PP. Therefore, a good understanding of PCF power plants make oil or natural gas fired power plants simpler to understand.

The major components of a pulverized coal fired power plant are (Figure 1):
- coal receiving, handling (crushing and pulverizing) and delivery to boiler
- boiler (steam generator) (Figure 2)
- turbine generator
- auxiliary equipment (i.e. fans, pumps, pulverizers, air heaters, ductwork, etc.)
- flue gas desulfurization system
- particulate control system
- ash handling system

**Figure 1.** Steam power plant (Sources: www.emt-india.net and www.made-in-china.com)

These summary notes will provide basic information on the following:
- Pulverized coal fired power plant performance
- Coal transportation, unloading and storage
- Environmental issues
- Environmental control systems
  - Particulate control
  - Flue gas desulfurization (FGD)
- Ash and FGD sludge disposal systems

2. Pulverized Coal Fired Power Plant Performance

The performance of an electric power plant is ultimately measured in terms of the amount of electricity it produces (useful output) per unit of fuel burned (required input). Thus for a given size power plant, the
amount of annual electricity production and the annual fuel (coal) consumption are the main parameters of interest.

The annual coal consumption of a power plant is a function of:
- net power generation capacity,
- steam cycle heat rate,
- steam generator efficiency,
- HHV of coal,
- penalty for stack gas reheat,
- allowance for auxiliaries,
- average load factor,
- equivalent availability factor.

Figure 2. Power plant boiler (Source: http://science-hamza.blogspot.ca)
2.1. Net Power Generation Capacity
The net power generation capacity is the net power that the power plant can supply to the grid at the busbar in one hour at full load, and is expressed in MW.

2.2. Steam Cycle Heat Rate
In a steam power plant, power is generated by the turbine generators that utilize steam produced in the boilers. The specific design of the steam cycle and its operating conditions (primarily, the steam supply and discharge conditions) dictate the pressure, temperature and flow rate of steam required to generate the specified power output. Steam cycle performance is commonly defined in terms of the steam requirement per unit of electric power generation (rather than the familiar thermal efficiency) and is referred to as the **Steam Cycle Heat Rate (SCHR)**, which, in North America, is expressed in Btu/kWh. Thus:

\[
SCHR = \frac{\text{Heat input into the steam cycle (Btu)}}{\text{Electricity generated (kWh)}}
\]

Since 1 kWh = 3,412 Btu

\[
SCHR = \frac{1}{\eta_{th}} \times 3,412 \text{ Btu/kWh}
\]

The principal design parameters that affect the steam cycle heat rate are:
- **Capacity**: Heat rate generally decreases as capacity increases due to turbine scaling, e.g. tip losses of a turbine decrease as blade length increases.
- **Reheat**: Heat rate decreases with the number of reheats. However, most large utility boilers have a single reheat. Some newer designs utilizing super-critical steam incorporate double reheat.
- **Steam temperature and pressure**: Heat rate decreases as the steam temperature and pressure increase. Maximum temperatures are in the range of 565°C (1050°F) as higher temperatures can cause corrosion problems. The steam pressure for large (>300 MW) sub-critical units is around 16.5 MPa (2400 psig) while for smaller units the pressure can be considerably lower, in the range of 10-16.5 MPa (1400-2400 psig). The super-critical plants utilize steam at a pressure of about 24 MPa (3500 psig) or more.
- **Feed water heaters**: Heat rate decreases as the number of feed water heaters are increased. Most utility systems have four or more feed water heaters.
- **Condenser pressure**: Heat rate decreases with decreasing condenser pressure since this allows a larger pressure drop across the turbine. The condenser pressure depends on the saturation temperature, which is set by the design of the heat rejection system. Lowest temperatures, consequently, lowest pressures are achieved with once-through water cooling from the ocean, lakes or rivers. If water from such sources is used, attention is paid to minimize the “thermal pollution” to protect the flora and fauna in the water body. If a large body of water is not available, then large cooling towers are used (Figure 3).

(Note: Many people confuse the water vapor that comes out of the cooling towers with “pollution”. But, it is just water vapor!)

Figure 3. Utility size cooling towers (Source: http://top-10-list.org)
It can be concluded from this brief review that the steam cycle heat rate depends on the thermodynamic efficiencies of the components and the overall design of the steam cycle; therefore, it is not affected by the boiler plant operating characteristics provided that steam at the design pressure, temperature and flow rate can be supplied by the boiler plant. However, if the boiler operating conditions change due to capacity changes or coal quality variations, the required steam conditions and flow may not be maintained, affecting the steam cycle heat rate. Thus, it can be assumed that if the boiler plant is designed for the range of coal to be supplied; the steam cycle heat rate can be treated as a fixed value independent of coal quality.

Commonly, sub-critical power plants operate with 16.5 MPa and 540°C (2,400 psig and 1,000°F) steam inlet conditions and single reheat, while super-critical power plants operate with 24 MPa and 540°C (3500 psig, 1000 F) steam inlet conditions and single reheat. Some super-critical plants have two reheat. Representative steam cycle heat rates for 250-1,000 MW capacity units are given in Table 1 for different condenser back pressure (turbine exhaust pressure) values.

Table 1. Representative steam cycle heat rates for large fossil central station turbine generators

<table>
<thead>
<tr>
<th>Steam</th>
<th>Nominal Rating MW, at 5.1 kPa, abs. (1.5 in Hg. abs.)</th>
<th>Steam Cycle Heat Rate (Btu/kWh) at Exhaust Pressure kPa (in Hg.), abs.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conditions</td>
<td></td>
<td>5.1 (1.5)</td>
</tr>
<tr>
<td>2400 psig, 1000 F initial, 1000 F reheat temperature</td>
<td>250</td>
<td>7850</td>
</tr>
<tr>
<td>3500 psig, 1000 F initial, 1000 F reheat temperature</td>
<td>500</td>
<td>7790</td>
</tr>
<tr>
<td></td>
<td>700</td>
<td>7860</td>
</tr>
<tr>
<td></td>
<td>1000</td>
<td>7920</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>7620</td>
</tr>
<tr>
<td></td>
<td>700</td>
<td>7670</td>
</tr>
<tr>
<td></td>
<td>1000</td>
<td>7710</td>
</tr>
<tr>
<td></td>
<td>1100</td>
<td>7680</td>
</tr>
</tbody>
</table>

(Source: Mark’s Mechanical Engineer’s Handbook, 1978)

2.3. Boiler (Steam Generator) Efficiency

The efficiency of a boiler is defined as the ratio of the useful heat supplied by the boiler (which is the amount of heat transferred to the steam) to the heat content of the fuel fired, i.e.,

\[
Boiler \ efficiency = \eta_{\text{Boiler}} = \frac{\text{Useful heat supplied by the boiler per kg of fuel fired}}{\text{Heat content of one kg of fuel fired}}
\]

Efficiency is a function of a number of parameters, such as the boiler design, operating and maintenance practices and fuel characteristics.

A commonly used and practical method to calculate the efficiency of a boiler is the "Heat Balance Method". Using this method, heat losses from a boiler are evaluated, and it is assumed that the remainder of the heat is absorbed to produce steam. Thus, efficiency can be expressed as:

\[
\text{Efficiency (\%)} = 100 - \sum \text{Losses (\%)}
\]
For boiler efficiency calculations, six major categories of heat losses are taken into consideration:

1. Heat loss in dry flue gas,
2. Heat loss due to moisture in combustion air,
3. Heat loss due to moisture in coal and the moisture generated from the combustion of hydrogen in coal,
4. Heat loss due to unburnt combustibles,
5. Heat loss due to radiation, convection and conduction to surroundings,
6. Heat losses unaccounted for.

Boiler efficiency is thus determined by subtracting the sum of these six groups of losses from 100.

The following parameters need to be known to calculate boiler efficiency:

• energy content or heating value of the coal (if unknown, can be estimated) (see Sect. 2.4),
• coal composition (ultimate analysis and proximate analysis),
• excess air,
• flue gas exit temperature.

Coal composition: Coal composition is reported on two bases: ultimate analysis and proximate analysis. Proximate Analysis: involves determining the moisture, volatile matter, and ash content by weight (%) and calculating the fixed carbon by difference. Proximate analysis may be reported in several ways:

- As received (used for combustion calculations)
- Moisture free (dry)
- Ash (or mineral matter) free

Ultimate Analysis: involves determining coal composition in weight (%) of C, H₂, N and S; Oxygen is determined by difference (used for detailed fuel studies and in heat balance computation).

Excess Air: Perfect, or stoichiometric combustion, is the complete oxidation of all the combustible constituents of a fuel, consuming exactly 100% of the oxygen in the combustion air. Excess air is any amount above this theoretical quantity. It is always necessary to use more than the theoretical air requirement to assure sufficient oxygen for complete combustion since it is not possible to have an ideally perfect mix of air and fuel in a boiler. On the other hand, the excess air that is not used in the combustion of the fuel leaves the boiler at the stack temperature, thus resulting in a heat loss. It is therefore necessary to keep the excess air at an optimum level in order to hold down the stack loss, but also accomplish near complete combustion of the fuel.

In practice, excess air is generally set manually or automatically to obtain complete combustion based on the flue gas analysis, and overridden when slagging or fouling problems develop. Experience has shown that the realistic range of excess air requirement for pulverized coal firing is between 15-30%.

Flue Gas Exit Temperature: The minimum flue gas exit temperature is dependent on the sulfur content of the coal fired. Sulfur oxides in the stack gases, produced as a result of combustion, react with water vapor to form sulfuric acid that condenses on the stack when the flue gas temperature is reduced below the condensation temperature of sulfuric acid. The condensation temperature is lower for high sulfur coals; however, experience with a large variety of coals indicates that a flue gas temperature maintained above 135°C (275°F) is sufficient for the safe operation of pulverized coal fired boilers.
2.4. Energy content or heating value

The energy content or heating value of a coal represents the amount of chemical energy in a given mass or volume of fuel. The heating value is generally expressed in kilojoules per kilogram (kJ/kg) (or, British thermal units per pound-mass, Btu/lbm). There are actually two heating values: a higher (gross) heating value (HHV) and a lower (net) heating value (LHV).

**HHV** is the amount of energy released as heat when a fuel undergoes complete combustion with oxygen under standard conditions, including the latent heat that is released as a result of condensing the water vapor in the combustion products. **LHV** is also the amount of energy released as a result of combustion, but excluding the latent heat of water vapor in the combustion products because it is assumed that the combustion products are not cooled below the saturation temperature of water. The difference between these two values is the latent heat of vaporization of the water vapor present in the exhaust products when the fuel is burned with dry air. In an actual combustion system, this includes the water present in the as-burned fuel (the moisture) and the water produced from the combustion of hydrogen, but it does not include any moisture that is introduced by the combustion air. Since the latent heat of vaporization of water at 3.4 kPa abs (the approximate partial pressure of the water vapor in the exhaust) is about 2,400 kJ/kg, the difference between the higher and lower heating values is approximated by the following equation which is applicable to any fuel on a mass basis:

\[
HHV - LHV = 2,400 \times (M + 9H_2) \quad \text{kJ/kg}
\]

where, M and H₂ are the moisture and hydrogen mass fractions of the fuel. Most combustion tables list the higher heating values for coal because the moisture content varies widely and this would change the lower heating value for each moisture value. When determining the fuel rate for a given power plant, the higher heating values on a dry, ash-free basis should be converted to an as-burned basis using the following formula:

\[
\text{As burned HHV} = (\text{Dry, ash free HHV}) \times (1 - M - A)
\]

where, M and A are moisture and ash contents expressed as a decimal.

In the absence of HHV data determined by bomb calorimetry tests, correlations such as the "Data Book Equation" developed by Mason and Gandhi¹ can be used to calculate the HHV of a coal from its ultimate analysis:

\[
HHV_{CLC} = 146.58 \times C + 568.78 \times H + 29.4 \times S - 6.58 \times Ash - 51.53 \times (O + N)
\]

where, \(HHV_{CLC}\) = calculated HHV on dry basis, Btu/lb
C, H, S, ASH, O, N = the respective contents of carbon, hydrogen, sulfur, ash, oxygen and nitrogen in weight %, on dry basis

2.5. Penalty for Stack Gas Reheat

In some wet Flue Gas Desulfurization (FGD) systems it is necessary to reheat the stack gas if reheating of stack gasses after SO₂ scrubbers is required to avoid condensation of sulfur and related corrosion problems, as well as other problems (to avoid a visible plume, to enhance plume rise and dispersion of pollutants). Power requirement for reheat can be determined based on the coal sulfur content and level of scrubbing done. For coals with a sulfur content of 3% or more, reheat is generally needed. The penalty for reheat is in the order of 2% of the gross heat rate.

---
2.6. Power Consumption of the Auxiliary Equipment (Allowance for Auxiliaries)
The auxiliary equipment of a power plant includes the coal handling and pulverizing equipment, boiler fans, condensate and booster pumps, cooling tower fans and circulating water pumps, soot blowers and other miscellaneous equipment. Some of the auxiliary equipment are operated by electric power while others utilize steam. In both cases, the power needed to run the auxiliaries is not available at the busbar; therefore, this power consumption should be added to the gross heat rate (GHR) to determine the net heat rate.

The power consumption of the auxiliary equipment, which is 5-10% of the gross heat rate, is mainly dependent on two factors: the design of the specific power plant equipment and the coal quality.

2.7. Power Plant Availability
Although availability is a frequently used term, there are a number of definitions and interpretations of it. These various interpretations and definitions are used to provide a measure of the time a power plant is capable of electrical generation. To understand the various definitions of availability and the reasoning for these, the operating scenario of a power plant should be understood.

At any point in time, an active power plant can be in any one of the following conditions:
1. Full capacity operation
2. Economic partial shutdown
3. Scheduled partial outage
4. Forced partial outage
5. Economic full shutdown
6. Scheduled full outage
7. Forced full outage

A possible scenario incorporating all of these conditions is depicted in Figure 4. The various definitions of availability are developed using the cumulative duration of these conditions in a prescribed time period, which is usually one year.

![Figure 4. Availability definitions](image)

The most basic measure of availability is the Availability Factor (AF):

\[
\text{Availability Factor (AF)} = \frac{AH}{PH} \times 100
\]
where, \( AH = \) Available hours = (Full and partial capacity generation hours) \( + (\text{Economic full shutdown hours}) \)
\( PH = \) Period hours

\[ AH = PH - [(\text{Forced full outage hours}) + (\text{Scheduled full outage hours})] \]

The usefulness and applicability of the Availability Factor is limited since the weighted effect of partial shutdowns and outages is not accounted for. A more general and meaningful measure of availability is the Equivalent Availability Factor (EAF), which is based on the equivalent full load hours when a plant is available to produce power:

\[
\text{Equivalent Availability Factor (EAF)} = \frac{AH - (EFPOH + ESPOH)}{PH} \times 100
\]

where,

\[
EFPOH = \text{Equivalent forced partial outage hours} = \frac{(\text{Forced partial outage hours}) \times (\text{Size of partial outage, i.e. derating})}{\text{Maximum dependable capacity}}
\]

\[
ESPOH = \text{Equiv. scheduled partial outage hrs} = \frac{(\text{Scheduled partial outage hours}) \times (\text{Size of partial outage, i.e. derating})}{\text{Maximum dependable capacity}}
\]

It is also possible to define EAF in terms of the total possible generation and lost generation due to outages as follows:

\[
EAF = \frac{T - F - P}{T}
\]

where, \( T = \) Total (maximum) possible MWh that can be generated in a given time period

\( F = \) MWh lost due to full and partial forced outages

\( P = \) MWh lost due to full and partial scheduled outages.

A similar concept is defined by the Capacity Factor (CF), which is based on only the actual amount of generation, thus,

\[
\text{Capacity Factor (CF)} = \frac{\text{Actual MWh generated}}{\text{(Max. dependable rating of plant)}(PH)}
\]

Economic shutdowns are conducted to trim generation that is not demanded, and scheduled outages are planned in advance so that they do not normally coincide with high demand periods. Forced outages, however, can occur at any point in time and they are the most costly to a utility. Therefore, the magnitude of the lost generation due to forced outages, a parameter that is not provided by the EAF or the CF, is of consequence in determining the costs associated with the reduction in availability. Utilizing EAF or CF as a measure of forced outage rates can be very misleading, as shown in Figure 5 where the operating scenarios of four power plants of same capacity are depicted. Plants 1 and 2 have the same EAF, but the actual generation of plant 2 is much less than that of plant 1; also, the ratio of actual generation to generation lost due to forced outage for plant 1 is high, indicating high reliability, whereas the same ratio for plant 2 is quite low indicating low reliability. On the other hand, a comparison of the CF’s of plants 3 and 4 indicates that the reliability of plant 3 is less than the reliability of plant 4 even though the CF’s indicate the opposite.
In summary, the costs of low availability cannot be attributed to EAF or CF alone. Assuming that the cost per hour of forced outage at a specific unit is constant, the costs should be proportional to the forced outage hours. The only exception to this is the base load plants, which, by definition, are expected to operate on a continuous basis. Thus, with base load plants, all of the lost generation, both due to forced as well as planned outages, has to be made up from more expensive sources.

Thus, the cost of lost availability to a utility due to forced outages is a function of the lost generation that would otherwise be available and sold, and the differential cost of replacement power, i.e.,

\[
\text{Cost incurred due to a reduction in availability (i.e. lost generation)} = \left( \text{MWH of lost generation} \right) \times \left( \text{Differential cost of replacement electricity} \right)
\]

where,

\[
\text{Differential cost of replacement electricity} = \left( \text{Cost of replacement electricity} \right) - \left( \text{Cost of own generation} \right)
\]

**Figure 5.** Relative comparison of capacity factor and equivalent availability

### 2.8. Average Load Factor

The average load factor (ALF) is expressed as a percentage and represents the level of utilization of the power plant. It is the product of the average load (%) and the equivalent availability factor (%). Thus:

\[
\text{Average load factor (ALF, %)} = \frac{[\text{Average load(%)}] \times [\text{EAF(%)}]}{100}
\]

where,

\[
\text{Average load (MW)} = \frac{\text{Average load (MW)}}{\text{Net plant capacity (MW)}} \times 100
\]
2.9. Annual Coal Consumption

Parameters to be determined or calculated:

- UNMW  Net unit generation capacity (MW)
- NUTS  Number of units in the power plant
- AL    Average load (%)
- EQAV  Equivalent availability factor (%)
- ALF   Average load factor (%) = (AL)(EQAV)/100
- AAX   Allowance for auxiliaries
- SCHR  Steam cycle heat rate
- SGE   Steam generator efficiency
- HHV   Higher heating value of coal (MJ/kg or Btu/lb)

With these parameters, the annual coal consumption can be calculated:

i) Calculate Gross Heat Rate (Btu/kWh):
   \[ GHR = \frac{SCHR}{(SGE/100)} \]

ii) Penalty for stack gas reheat (Btu/kWh) – if applies:
    \[ PSGR = GHR \times 0.02 \]

iii) Net Heat Rate (Btu/kWh)
    \[ NHR = GHR + PSGR + AAX \]

iv) Heat input to steam generator at full load (Btu/h)
    \[ HISGFL = UNMW \times NHR \times 1000 \]

v) Coal burn rate at full load (tons/h/unit)
   \[ CBRFL = \frac{HISGFL/HHV}{2,000} \]

vi) Coal burn rate at average load (tons/h/unit)
    \[ CBRAL = CBRFL \times \frac{AL}{100} \]

vii) Annual coal consumption of the power plant at ALF (tons/year)
    \[ ACCALF = NUTS \times CBRFL \times \frac{AL}{100} \times 24 \times 365 \]

2.10. Annual Ash and SO\textsubscript{2} Generation

Once the annual coal consumption is determined and the coal ash content is known, the amount of fly ash generated annually can be calculated:

\[ FLYAGA = ACCALF \times \frac{ASH}{100} \times FLYAFR \]

where,
- FLYAGA = fly ash generated annually, tons/year
- ACCALF = annual coal consumption of power plant
- ASH = ash content of coal by weight, %
FLAFR = fraction of total ash that appears in the flue gas, this is between 0.7-0.8 for pulverized coal firing

The amount of ash that does not leave the furnace with the flue gas is deposited as slag or bottom ash. When removed, slag is also collected with bottom ash, therefore all of the ash that remains in the furnace can be treated as bottom ash. Thus, the amount of bottom ash generated annually is:

\[
BOTAGA = ACCALF \times \frac{ASH}{100} \times (1 - FLAFR)
\]

where, BOTAGA = bottom ash generated annually, tons/year.

Similarly, the amount of sulfur dioxide emitted annually via the stack can be calculated as follows:

\[
SO2GA = ACCALF \times \frac{S}{100} \times SO2FR \times 2
\]

where, SO2GA = sulfur dioxide generated annually, tons/year

S = sulfur content of coal by weight, %

SO2FR = fraction of sulfur dioxide that appears in the flue gas, this is about 0.85 for pulverized coal firing

2 = factor to account for the weight of oxygen in SO2

Another useful parameter, especially required to determine the sulfur dioxide removal requirement, is the potential sulfur dioxide emissions, which is expressed in lb/million Btu fired. This parameter can be calculated as follows:

\[
SO2EM = \frac{20,000 \times S}{HHV}
\]

where, SO2EM = potential SO2 emissions, lb/million Btu fired.

3. Coal Transportation, Unloading and Storage

Transportation of coal has historically been responsible for a substantial portion of its total cost. In many cases, transportation expenses can account for up to 50% of the delivered price of coal. Due to high transportation costs, projects are not started until a reasonable fuel source is established and a reasonable fuel transportation arrangement secured. Selection of an appropriate method of transporting the coal is therefore critical. The selection process essentially requires consideration of the following factors:

- availability of transportation facilities such as roads, railways and navigable waterways,
- the cost associated with each transportation mode,
- site specific factors such as environmental impacts, contract restrictions, regulatory constraints and handling facilities.

The methods of coal transportation are rail, barge, truck, slurry pipeline, conveyor, and ocean-going dry bulk carriers (ships). Increasingly, the optimal solution involves more than one particular mode of transportation. Ocean-going dry bulk carriers are used in export markets, primarily in the movement of large quantities of coal from major coal exporting countries such as USA, Canada, Australia, South Africa, China, and Russia to coal importing countries in Europe, Pacific Rim, and Latin America. Use of conveyors is mostly suitable for movements within facilities, or if the power plant is close to the coal mine, and the necessary right-of-way can be obtained.
3.1 Transportation of coal by rail

About 60% of the coal utilized by the utility industry is transported via rail. Depending on the annual volume, coal can be shipped in single carlots, multiple carlots or unit trains. A unit train is the most efficient method of transporting bulk commodities, such as coal, by rail. It consists of a dedicated set of locomotives and freight cars that stay together as a unit for the loaded movement and empty return on a regular scheduled basis between specified points of origin and destination. Many cargoes are carried in unit trains, including chemicals, petroleum products, grain and minerals. However, coal accounts for more rail shipments than any other commodity, and most of this coal moves in unit trains. Compared to unit train transportation, transporting coal using single car shipments is highly impractical and far too expensive. Therefore, this mode is hardly ever used for any sizable annual volume. In Canada, unit train operations are mainly between Western Canada coalfields, British Columbia export terminals and Central Canada markets.

A typical modern unit coal train generally comprises about 100 cars, each car carrying some 100 tons of coal, plus three to five locomotives, depending on the grades and curves. This 10,000 ton train continually operates between the source of coal and the generating plant - in essence, one basic origin, one basic destination, and car equipment remaining as a unit and operated as a shuttle. Predetermined schedules for train loading, haulage volumes, mine departure, plant arrival, train unloading, turn around and mine return permit the railroads to optimize operating conditions, while providing required coal deliveries to the plants on time. The advantages of unit trains can be seen in Table 1 where unit train characteristics are compared with those of an average train.

Due to the differences between the coal unit train and an average train, the maintenance characteristics are considerably different, favoring coal unit trains on an economical basis. Similarly, the fuel consumption per revenue-ton-mile (RTM) and gross-ton-mile (GTM) for a coal unit train is about 50% lower than an average train operating on a similar route due to the following reasons:

- the horsepower to gross-trailing-ton ratio is generally lower for unit trains.
- coal unit trains generally operate at lower speeds.
- coal units spend less time in idling than units used in regular freight trains.
- the ratio of GTM to RTM is generally lower for coal unit trains, mainly because their payload to tare weight ratio is higher on average.

Table 1. Unit train characteristics compared to the average US train

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Unit Train</th>
<th>Average Train</th>
</tr>
</thead>
<tbody>
<tr>
<td>Car capacity (tons)</td>
<td>100</td>
<td>78</td>
</tr>
<tr>
<td>Car load (tons)</td>
<td>99</td>
<td>67</td>
</tr>
<tr>
<td>Percent mileage loaded</td>
<td>50</td>
<td>55</td>
</tr>
<tr>
<td>Cars per train</td>
<td>90</td>
<td>68</td>
</tr>
<tr>
<td>Train load (tons)</td>
<td>9110</td>
<td>2200</td>
</tr>
<tr>
<td>Annual car mileage</td>
<td>50-100,000</td>
<td>22,000</td>
</tr>
<tr>
<td>Locomotives per train</td>
<td>5</td>
<td>2</td>
</tr>
<tr>
<td>Miles per day</td>
<td>275 (100-300)</td>
<td>60</td>
</tr>
<tr>
<td>Loads per year</td>
<td>30-100</td>
<td>10</td>
</tr>
</tbody>
</table>

The locomotives that are mainly used for coal unit train operations are the large 3000-3600 HP diesel-electric units. Smaller 1000-1500 HP switching engines are generally used for mine/power plant chores.
The large standard long haul locomotive weighs about 185-200 tons and can handle a tractive effort (drawbar-pull) of 90,000 lb at 10 mph. Generally a four-stroke, turbocharged diesel engine is the power source, although two-stroke and normally aspirated engines are also used. An alternator, directly connected to the engine furnishes power to axle-mounted traction motors that are generally direct current type. The traction motors can also be used for braking the locomotive electrically, by operating them as generators and dissipating the electric power in resistors. The train, as well as the locomotive, is furnished with air brakes.

Two types of rail cars are used in coal unit trains: the hopper-bottom car and the rotary-dump gondola car (Figure 6). A hopper car can be identified by the angled or saw-tooth like hoppers projecting beneath the car between the front and rear wheel trucks. For bottom-dump unit train coal unloading the hatches of these hoppers are opened, generally automatically, with the car positioned over the utility's unloading facility. Unloading is usually accomplished while the train moves at a speed of 1-2 mph. Hopper cars are heavier and more expensive than a comparable gondola car due to the elaborate hatches, their support mechanisms and the opening systems. On the other hand, the gondola car is a simple box on wheels. The car is turned upside down by a rotary unloader at the unloading facility, and the coal flows freely from the open top. To permit this operation, a rotary-swivel coupling, rather than a rigid-shank, non-rotary coupling, is used. Most of the hopper bottom and gondola cars have a capacity of about 4000 cu ft, although cars as small as 2000 cu ft are also being used. Due to the general preference of the utilities towards the rotary-dump unloading, many hopper cars are equipped with rotary couplings. Rotary gondola as well as rapid discharge hopper cars can unload in 1-2 minutes. The speed of unloading can be increased by using larger pits that can accommodate two to six cars unloading simultaneously.

Figure 6. Hopper bottom rail car, and rotary-dump gondola car being unloaded
(Sources: www.teamtracktrading.co.uk, www.picstopin.com)

3.2. Transportation of coal by barge
Coal movement by barges is primarily on inland waterways and the Great Lakes. Consideration of barging as a possible transportation mode requires consideration of many factors, the most fundamental being:
- location of mine site(s) and power plant site(s) with respect to the waterway,
- physical characteristics of the waterway, such as lock size and channel depth, and hence equipment needs,
- availability of channels which are not critically affected by traffic, weather, etc.,
- availability of loading, unloading and transfer terminals.
The movement of coal traffic on inland waterways is accomplished primarily by towboats pushing flotillas of barges. Towboats range in size from less than 1000 HP to 10,000 HP, with the average horsepower rating of towboats in use about 5000 HP. Horsepower ratings are restricted due to the physical characteristics of waterway systems such as lock size and channel depth. Commonly, barges with a capacity of 1500 tons with dimensions 195 ft x 35 ft x 12 ft are used.

The size of the flotilla is usually determined based on the constraints imposed by the specific waterway to be used. A flotilla can consist of as many as 45 barges on the lower Mississippi river, and as few as 4 barges on some of the smaller waterways. However, the normal practice is to push 15 barges, 3 wide and 5 long, for a single lockage in the 1200 ft lockage system.

Bulk vessels are of two types, the traditional bulk vessel that cannot self-unload, and the self-unloaders. The unloading methods and facilities required for each type are different. There are mainly two methods of unloading the traditional vessels: using cranes with clamshell buckets and the continuous bucket ladder (Figure 7).

![Figure 7. Clamshell bucket and continuous ladder unloader](on30insider.com, qzhbix.en.alibaba.com)

High-speed cycle clamshell unloaders have capacities up to 500 tonnes per hour, which can be multiplied by operating several clamshell unloaders mounted on one stationary tower, which also reduces installation and operation costs. The continuous bucket ladder is dropped into the hold of the vessel for continuous unloading at rates up to 4,000 tonnes per hour. In addition to a higher unloading rate than the normal clamshell buckets, these installations have lower maintenance cost, lower power consumption, reduced barge maintenance and better cleanup characteristics.

A newer development in unloading barges is the self-unloader. Self-unloader vessels require only a transfer hopper on the pier. Barges of 5,000 dwt and ships of 25,000 to 70,000 dwt are currently equipped with double skin holds which house belt and/or screw conveyors. These conveyors reclaim coal from the hold and bring it to the deck, where an outreach conveyor delivers the material to the onshore stockpile or hopper. Self-unloading rates of 2,500 - 4,000 tonnes per hour can be achieved.
3.3. Transportation of coal by trucks
Among the principal gathering/distribution systems for coal is over-the-road trucking. In the US, about 75% of all coal moves by truck at some stage in its journey from the mine to the consumer. Generally, trucks are utilized as an alternative to barge and rail transportation when these cheaper modes of transportation are unavailable or insufficient, and especially when terrain problems are significant. However, the major users of truck transportation are smaller coal producers and consumers, particularly for short line hauls. With the well-developed road infrastructure already in place, the small producers view trucking as the least capital-intensive service that can be readily increased or decreased to meet the demands of often dispersed consumers within a regional market area. Aside from the economic factors, there are two potentially important constraints on the transport of coal by trucks: the ability of roads to take the coal traffic, and the environmental constraints.

The trucks used in coal transportation are tractor-trailer type heavy trucks that require specially designed and constructed roads. If coal trucks start to travel on a road designed for passenger traffic and regular commercial operation, the road will quickly deteriorate and all road users will suffer. Therefore, increased maintenance, substantial modifications and reconstruction of roads are required if coal traffic is going to be taking place. To somewhat control the wear and tear on roads, every province in Canada and every state in the US has restrictions on the allowable gross vehicle weight (GVW) of trucks. Commonly, the trucks that are used for transporting coal are the tandem tractor and 3-axle semi-dumptrailer type arrangements with 30 - 35 ton payload capacity, since this combination provides the most suitable operation and makes use of the maximum allowable GVW.

There are a number of environmental objections to the road transport of coal. Heavy coal trucks can be a safety hazard to pedestrians and other road vehicles. Also, coal trucks cause traffic slow-down on narrow or winding roads, increase noise levels, cause vibration and fugitive dust problems and emit fumes. These problems are increased if the roads are in poor condition, which may be as a result of the coal traffic itself.

The primary factor that has limited the use of trucks is the relatively high cost of trucking operations. The inherent limiting economic factors include lower tonnage movements per unit of fuel (8-10:1 as compared to barge and 3-4:1 as compared to rail), higher manpower requirements (1 driver per 20-35 ton truck vs. 1 crew member for every 2000-3500 tons in rail or barge operations), higher capital costs, higher maintenance costs and generally lower economies of scale.

3.4. Transportation of coal by slurry pipeline
A coal water slurry pipeline transportation system consists of pipelines, pump stations and associated process facilities that operate in conjunction to move coal particles dispersed in water. At the beginning of the system is the slurry preparation facility where grinding and slurrification equipment produces a controlled coal-water mixture for injection into the pipeline system. The pipeline is sized and designed by considering the hydraulic characteristics of the solid-liquid two-phase flow. Pump stations are positioned at appropriate locations along the pipeline to input energy required to overcome the pressure losses encountered by the slurry. The terminal point of a slurry transportation system has facilities and equipment for storing, thickening and dewatering the slurry. Throughout the transportation facility, instrumentation and controls are used to measure variables (flow, pressure, density, etc.) and implement an operation philosophy. During the 1980’s there was increased interest in this technology, and several projects were under design and development stage for large capacity (larger than 10-15 million tons per year - MTY) and long distance (about 1000 mi or more) transportation of coal, since operating economy improves due to reduction in power consumption per unit tonnage of coal. However, for the large coal slurry pipelines to exist, cooperation from at least one multi-plant (coal fired) electric utility is needed because even the largest single power generating station consumes about 7 MTY, which is not sufficient.
to sustain the operation of a large capacity pipeline. On the other hand, the largest producing mines have an output of less than 10 MTY. Thus, large capacity pipelines have to be multiple source, multiple supply arrangements, which also enables the pipeline to be classified as a common carrier. Aside from these issues, other obstacles for coal-slurry pipelines included the resistance from railways and difficulties in obtaining right-of-way. Thus, the projects were not built, and in the present environment, coal slurry pipelines are not conceived to be viable.

3.5 Coal storage and reclamation
Coal storage can be divided into two types: live (active) storage, which supplies coal directly to the process, and dead (reserve) storage, which guards against transportation delays. In certain instances, a storage area may serve as both live and dead storage in that the area will be built up for period of time, and than depleted as coal is reclaimed.

The potential effects of storage on the characteristics of coal are:
- Slacking (size degradation): Slacking or weathering is caused by the slow evaporation of moisture from within the coal, with resultant shrinkage, which breaks up the coal particle.
- Burning characteristics and grindability index may increase or decrease for oxidized coal.
- Loss in calorific value from oxidation
- Formation of acidic run-off water (sulfuric or sulfurous acid, and possibly some hydrochloric acid)
- Spontaneous combustion: All of the organic elements, as well as some of the metallic elements, such as iron react with oxygen when the coal is exposed to air. Some react at much higher rates than others do, but all with liberation of energy in the form of heat. If the heat generated by oxidation cannot be released from a coal pile, the temperature of the pile increases to the level at which active combustion occurs. This is known as spontaneous combustion.
- Explosion in confined spaces, silos, bunkers: "gassy" coals, following size diminution, such as crushing or pulverizing, may release large volumes of methane gas that can create an explosion hazard.

The options for storage are either open or closed. In general, open storage areas are for higher capacity storage because of their lower cost. Most dead storage facilities are open, because they are normally designed to store larger tonnages than live storage areas. However, due to the following reasons, closed storage is gaining strong popularity:
- environmental: closed storage eliminates dust and run-off from the coal, minimizing pollution,
- space considerations: closed storage in the form of silos, requires less land for the same capacity,
- protection from weathering and freezing: closed storage protects the coal from the elements, minimizing deterioration and losses
- esthetics.

Open storage is the least expensive of all storage methods. It consists of storing the coal directly on the ground or in shallow pits in several configurations. Adequate consideration must be given to the open stocking of coal to avoid spontaneous combustion and to reduce oxidation rate, which degrades coal and reduces its calorific value.

The most common open storage configurations are the conical-shaped pile and the long wedge shaped pile. Conical stockpiles have varying capacities depending on the height of the pile and the angle of repose of the coal. Buildup of this type of pile is usually by a telescoping chute or a stacking tube (Figure 8). The telescoping chute is sectionalized so that it can be raised and lowered to minimize the drop height. The stacking tube consists of a concrete or metal tube with outward opening doors at various locations along the height of the tube. Coal dumped down the tube discharges through the door at the
lowest level. As level rises, coal is discharged at progressively higher doors. The wedge shaped piles are built/reclaimed with a travelling stackers, reclaimers and stacker-reclaimers (Figure 9) that operate with a belt conveyor running parallel to the pile, and the movable tripper slowly traversing the length of the pile. The conical and the wedge shaped piles may also be reclaimed by under-the-pile conveyor systems. Several openings may be used for the piles to reduce the amount of dead storage.

Closed storage facilities are generally in the form of bins or silos. These are predominantly circular in shape and made of steel or concrete. Steel bins are selected for tonnages of 300 to 500, whereas concrete silos of 15,000 tonnes or more have built. Silos and bins have arrangements to withdraw coal through the bottom such as a surface or buried conveyor of a variety of types. The bottoms of the silos are designed with sloping sides to assure recovery of coal by gravity. Large diameter silos generally have more than one feeder chute at the bottom to provide better withdrawal.

![Figure 8](Source: www.polimak.com/Telescopic_Chute.htm, www.mariettasilos.com/stacking_tubes)

**Economic Considerations for Determining the Size of Coal Storage**

The size of coal storage should be determined based on three factors in the absence of land availability limitations:

1. Estimated duration and frequency of coal supply breakdowns,
2. Cost of shut-down of plant due to coal shortage, or if possible, buying coal or power from emergency sources,
3. Cost of storage facilities and inventory carrying charges.

The capacity of coal storage should be large enough to avoid coal shortages during supply breakdowns. This will guarantee uninterrupted power generation, which is of utmost importance. However, if the analysis to determine the storage capacity is based solely on this factor, it is likely that higher safety factors will be used resulting in oversized storage capacities. On the other hand, capital and operating costs of storage facilities and inventory carrying charges increase as the capacity increases. The cost of storage facilities, especially for open storage, is not very high. More important are the inventory carrying charges due to the large amounts of coal kept in storage. Coal in storage represents tied-up capital, which does not produce any return, but has a cost to the owner.
60-day storage vs. 30-day storage inventory carrying charges for a 1,000 MW generating station are compared for illustrative purposes using 5% interest rate:

Coal consumption rate of a typical 1,000 MW plant is 500 tonnes per hour. Using this rate, required capacities are:

- 30-day storage: \(500 \times 24 \times 30 = 360,000\) tonnes
- 60-day storage: \(1000 \times 24 \times 30 = 720,000\) tonnes

Using $60 per tonne for the cost of coal, the additional inventory carrying charges for 60-day storage is:

\[(720,000 - 360,000) \times 60 \times 0.05 = $1,080,000/yr\]

Thus, the magnitude of carrying charges, which is the cost of maintaining storage, is substantial. Therefore, it is of economic concern to determine the size of coal storage based on a risk analysis incorporating economic parameters to avoid unnecessary inventory carrying charges, and coal shortages.

![Figure 9. Stacker, reclaimer and stacker/reclaimer (Source: www.ubemachinery.co.jp)](image)
4. Environmental Issues Related with Coal Based Energy Conversion

As primary energy is converted into secondary energy (for example coal to electricity, nuclear to electricity), environmental pollutants are generated which affect the atmosphere, the water (surface and underground), living organisms and the land. A study of these pollutants, the formation mechanisms and the means to minimize their generation, emission and impacts on the environment are the subject matter of several university courses, primarily in the field of Environmental Engineering. The knowledge base and literature in this area have been growing at a fast rate and it is possible to find many references in any library.

To keep the subject matter to a manageable size, the focus of this review is significantly narrowed to cover only air pollution from the utilization of coal in electric power plants. This choice was made considering that (i) coal is the dominant fuel used in electricity generation, (ii) it is considered a dirty fuel primarily due to its environmental (largely air pollution) impacts, and (iii) air pollution has far reaching and long lasting effects on the environment. In fact, environmental impacts of coal related activities are much more than the air pollution, and include noise and vibration, alteration of topography, acidic drainage, solid and liquid wastes, occupational health and fire hazards.

4.1 Air pollution

Air pollution may be defined as any atmospheric condition in which substances are present at concentrations high enough above their normal ambient levels to produce a measurable effect on the environment. Air pollution affects the health of human beings and animals, damages vegetation, soils and materials, affects climate, reduces visibility and solar radiation, impairs comfort and production processes. While some of these effects are specific and quantifiable (such as reduced visibility, damage to vegetation) others are not easily quantifiable (such as effects on human health, reduced comfort).

Air pollutants can be classified into two general categories:
1. Primary pollutants: these are emitted directly from sources
2. Secondary pollutants: these are formed in the atmosphere by chemical interactions among primary pollutants and normal atmospheric constituents.

Air pollutants can be classified as follows:
1. Sulfur containing compounds
2. Nitrogen containing compounds
3. Carbon containing compounds (excluding CO and CO₂)
4. CO and CO₂
5. Halogen compounds
6. Particulate matter
7. Radioactive compounds

The Emissions Database for Global Atmospheric Research (EDGAR) provides global past and present day anthropogenic emissions of greenhouse gases and air pollutants by country and on spatial grid (http://edgar.jrc.ec.europa.eu/index.php). The composition of dry air at sea level and 25°C is given in Table 3. The air quality objectives and standards for Canada are given in Table 4. In the following sections, air pollutants emitted from coal fired power electric power plants, i.e. sulfur containing compounds (SOₓ), nitrogen containing compounds (NOₓ), CO and CO₂, and particulate matter will be discussed in more detail.

---

² "Environment" includes living things as well as non-living things around us.
There are two ways in which the concentration of air pollutants is normally expressed:

1. **ppm**: parts per million by volume, i.e. volume fraction $\times 10^6$
   - Thus: $\text{ppm} = \frac{V_i}{V} \times 10^6$
   - where $V_i$ and $V$ are volumes of species i and air, respectively, at pressure $p$ and temperature $T$
   - Also, $\text{ppm} = \frac{c_i}{c} \times 10^6$
   - where $c_i$ and $c$ are moles per volume of species i and air, respectively, at pressure $p$ and temp $T$.
   - Sometimes pphm (parts per hundred million) and ppb (parts per billion) are also used.

2. **µg/m}^3**: weight of pollutant per volume of air in micrograms per cubic meter

### Table 3. Composition of dry atmosphere, by volume (Source: Wikipedia)

<table>
<thead>
<tr>
<th>Gas</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen ($N_2$)</td>
<td>780,840 ppmv (78.084%)</td>
</tr>
<tr>
<td>Oxygen ($O_2$)</td>
<td>209,460 ppmv (20.946%)</td>
</tr>
<tr>
<td>Argon (Ar)</td>
<td>9,340 ppmv (0.9340%)</td>
</tr>
<tr>
<td>Carbon dioxide ($CO_2$)</td>
<td>394.45 ppmv (0.039445%)</td>
</tr>
<tr>
<td>Neon (Ne)</td>
<td>18.18 ppmv (0.001818%)</td>
</tr>
<tr>
<td>Helium (He)</td>
<td>5.24 ppmv (0.000524%)</td>
</tr>
<tr>
<td>Methane (CH$_4$)</td>
<td>1.79 ppmv (0.000179%)</td>
</tr>
<tr>
<td>Krypton (Kr)</td>
<td>1.14 ppmv (0.000114%)</td>
</tr>
<tr>
<td>Hydrogen (H$_2$)</td>
<td>0.55 ppmv (0.000055%)</td>
</tr>
<tr>
<td>Nitrous oxide ($N_2O$)</td>
<td>0.325 ppmv (0.0000325%)</td>
</tr>
<tr>
<td>Carbon monoxide (CO)</td>
<td>0.1 ppmv (0.00001%)</td>
</tr>
<tr>
<td>Xenon (Xe)</td>
<td>0.09 ppmv (9×10$^{-6}$%) (0.000009%)</td>
</tr>
<tr>
<td>Ozone ($O_3$)</td>
<td>0.0 to 0.07 ppmv (0 to 7×10$^{-6}$%)</td>
</tr>
<tr>
<td>Nitrogen dioxide (NO$_2$)</td>
<td>0.02 ppmv (2×10$^{-6}$%) (0.000002%)</td>
</tr>
<tr>
<td>Iodine (I$_2$)</td>
<td>0.01 ppmv (1×10$^{-6}$%) (0.000001%)</td>
</tr>
<tr>
<td>Ammonia (NH$_3$)</td>
<td>trace</td>
</tr>
</tbody>
</table>

*Not included in above dry atmosphere:*

| Water vapor ($H_2O$) | ~0.40% over full atmosphere, typically 1%–4% at surface |

ppmv: parts per million by volume (note: volume fraction is equal to mole fraction for ideal gas)

### Table 4. National Ambient Air Quality Objectives – Canada


<table>
<thead>
<tr>
<th>Air Contaminant</th>
<th>Maximum Desirable Level</th>
<th>Maximum Acceptable Level</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sulphur Dioxide</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual arithmetic mean</td>
<td>30 µg/m$^3$ (0.01 ppm)</td>
<td>60 µg/m$^3$ (0.02 ppm)</td>
</tr>
<tr>
<td>Average concentration over a 24-hour period</td>
<td>150 µg/m$^3$ (0.06 ppm)</td>
<td>300 µg/m$^3$ (0.11 ppm)</td>
</tr>
<tr>
<td>Average concentration over a 1-hour period</td>
<td>450 µg/m$^3$ (0.17 ppm)</td>
<td>900 µg/m$^3$ (0.34 ppm)</td>
</tr>
<tr>
<td><strong>Suspended Particulate Matter</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual geometric mean</td>
<td>60 µg/m$^3$</td>
<td>70 µg/m$^3$</td>
</tr>
<tr>
<td>Average concentration over a 24-hour period</td>
<td></td>
<td>120 µg/m$^3$</td>
</tr>
<tr>
<td><strong>Carbon Monoxide</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average concentration over an 8-hour period</td>
<td>6 mg/m$^3$ (5 ppm)</td>
<td>15 mg/m$^3$ (13 ppm)</td>
</tr>
<tr>
<td>Average concentration over a 1-hour period</td>
<td>15 mg/m$^3$ (13 ppm)</td>
<td>35 mg/m$^3$ (31 ppm)</td>
</tr>
<tr>
<td><strong>Oxidants (Ozone)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average concentration over a 1-hour period</td>
<td>100 µg/m$^3$ (0.05 ppm)</td>
<td>160 µg/m$^3$ (0.08 ppm)</td>
</tr>
<tr>
<td><strong>Nitrogen Dioxide</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual arithmetic mean</td>
<td>60 µg/m$^3$ (0.03 ppm)</td>
<td>100 µg/m$^3$ (0.05 ppm)</td>
</tr>
<tr>
<td>Average concentration over a 1-hour period</td>
<td>400 µg/m$^3$ (0.21 ppm)</td>
<td></td>
</tr>
</tbody>
</table>

* Conditions of 25°C and 101 kPa are used as the basis for conversion from µg/m$^3$ to ppm.
4.2. Sulfur containing compounds (SO\textsubscript{x})

Sulfur is a relatively abundant element, and it is present in the atmosphere as a result of emissions from both natural and anthropogenic sources. The main natural sources of atmospheric sulfur are geothermal activity, sea-spray and biological decay. Anthropogenic emissions of sulfur, are generally in the form of SO\textsubscript{2} (sulfur dioxide). In addition, small amounts of SO\textsubscript{3} (sulfur trioxide) are also released. These sulfur emissions result mainly from the combustion of fossil fuels that contain sulfur (primarily by thermal power plants) and smelting of sulfur-containing ores. In Canada more than 40% of sulfur emissions comes from non-ferrous smelters.

The increased concentration of sulfur in the atmosphere has adverse effects on the environment. Most important of these are increased heart and lung diseases, and acid rain, which affects vegetation and aquatic life. SO\textsubscript{2} is highly soluble, and consequently is absorbed in the moist passages of the upper respiratory system. Exposure to SO\textsubscript{2} levels of the order of 1 ppm leads to constriction of the airways in the respiratory tract.

As noted above, when fuels that contain sulfur (such as coal and oil) are burned, the sulfur is released mostly as SO\textsubscript{2}, but small amounts of SO\textsubscript{3} are also released. SO\textsubscript{2} can also coverts into SO\textsubscript{3} in a series of reactions in the atmosphere which involve a free radical such as OH\textsuperscript{-}. OH\textsuperscript{-} radical forms when atomic oxygen reacts with water:

\[
O + H_2O \rightarrow 2OH^- 
\]

ThisOH\textsuperscript{-} radical reacts first with SO\textsubscript{2} then with water to form sulfric acid:

\[
\text{SO}_2 + \text{OH}^- \rightarrow \text{HOSO}_2 \\
\text{HOSO}_2 + \text{O}_2 \rightarrow \text{SO}_3 + \text{HO}_2 \\
\text{SO}_3 + \text{H}_2\text{O} \rightarrow \text{H}_2\text{SO}_4 
\]

Sulfric acid molecules rapidly become particles by either condensing on existing particles in the air or by merging with water vapor to form H\textsubscript{2}O-H\textsubscript{2}SO\textsubscript{4} droplets. The sulfuric acid particles and droplets end up on the vegetation, soil and surface waters as acid rain. Acid rain has the following impacts on the environment:

- damages vegetation,
- increases the acidity of surface waters killing fish and plants, and reaches the ground water,
- discolors paints, corrodes metals and causes inorganic fibers to weaken,
- damages building marble, limestone and mortar. The reaction between limestone (CaCO\textsubscript{3}) and sulfric acid shows the following replacement:

\[
\text{CaCO}_3 + \text{H}_2\text{SO}_4 \rightarrow \text{CaSO}_4 + \text{CO}_2 + \text{H}_2\text{O} 
\]

The calcium sulfate (CaSO\textsubscript{4} - gypsum) produced by this reaction is water-soluble and easily washes away leaving a pitted, eroded surface. Many of the world's historic buildings and statues are rapidly being degraded due to this exposure.

Due to the adverse effects of sulfur on the environment, many industrialized countries have imposed legislation directed at controlling emissions of sulfur from various sources, particularly those from coal combustion. In most industrialized countries, SO\textsubscript{2} emission reduction requirements vary between 85-90%. For Canada, the “Thermal Power Generation Emissions-National Guidelines for New Stationary Sources” is given in: www.ec.gc.ca/lcpe-cepa/default.asp?lang=En&n=B5E8C54A-1

The 1979 New Source Performance Standards promulgated by the Environmental Protection Agency of the USA dictate the allowable SO$_2$ emissions from 73 MW and larger coal fired electric utility steam generation units for which construction is commenced after September 1978. The NSPS standards require at least 90% reduction of potential SO$_2$ emission and limit SO$_2$ emission rates to 1.2 lb/10$^6$ Btu, or require at least 70% reduction and limit SO$_2$ emission rates to 0.6 lb/10$^6$ Btu. In mathematical notation, the NSPS standards can be expressed as follows:

\[
\begin{align*}
SRREQ & = 0.7 & \text{for } (0.3) \text{ (SO2EM)} < 0.6 \\
SRREQ & = \text{SO2EM} - 0.6/ \text{SO2EM} & \text{for } (0.1) \text{ (SO2EM)} < 0.6 \\
SRREQ & = 0.9 & \text{for } 0.6 \leq (0.1) \text{ (SO2EM)} < 1.2 \\
SRREQ & = \text{SO2EM} - 1.2/ \text{SO2EM} & \text{for } (0.1) \text{ (SO2EM)} \geq 1.2
\end{align*}
\]

where, \(SRREQ\) = SO$_2$ removal requirement, decimal

\[
\begin{align*}
\text{SO2EM} & = \text{potential SO2 emissions, lb/10}^6 \text{ Btu} = (20,000) (S)/\text{HHV} \\
S & = \text{coal sulfur content, } \% \text{ by weight} \\
\text{HHV} & = \text{higher heating value of coal, Btu/lb}
\end{align*}
\]

By comparison, allowable SO$_2$ emissions from gas/oil fired power plants is 0.2 lb/10$^6$ Btu (86 g/10$^6$ kJ).

### 4.3 Nitrogen containing compounds (NO$_X$)

Seven oxides of nitrogen are known to occur: NO, NO$_2$, NO$_3$, N$_2$O, N$_2$O$_3$, N$_2$O$_4$, and N$_2$O$_5$. Of these, only nitric oxide (NO) and nitrogen dioxide (NO$_2$) are important in the study of air pollution. Of the two, NO is by far the largest of the nitrogen oxides (NO$_X$) emissions. There are two sources of NO$_X$ emissions from the combustion of fossil fuels:

1. **Thermal NO$_X$:** is formed when nitrogen and oxygen in the combustion air are heated to a high enough temperature (above about 1000 K) to oxidize the nitrogen. This occurs primarily through a chain reaction known as Zeldovich reactions:

   First the oxygen in combustion air is atomized:
   \[
   O_2 + N_2 \rightarrow O + O + N_2
   \]

   The oxygen atom reacts with nitrogen to produce nitrogen monoxide (NO) and a nitrogen atom:
   \[
   O + N_2 \rightarrow NO + N
   \]

   The nitrogen atom reacts with either oxygen or hydroxyl radical (OH) at peak temperature to form NO and either an oxygen atom or a hydrogen atom, respectively:
   \[
   N + O_2 \leftrightarrow NO + O \\
   N + OH \leftrightarrow NO + H
   \]

   When the concentration of oxygen atoms reaches equilibrium, the atoms will combine and return to molecular state:
   \[
   O + O + N_2 \leftrightarrow O_2 + N_2
   \]

   Further oxidation of the NO formed results in NO$_2$:
   \[
   2NO + O_2 \rightarrow 2NO_2
   \]

   Thermal NO formation is directly proportional to the nitrogen concentration, the residence time, the square root of the oxygen concentration and the exponential of temperature:

   \[
   [\text{NO}] \sim [N_2] \text{ [residence time]} [O_2]^{1/2} \text{ [exp } (1/\text{temperature})]\]

   NO$_X$ emissions from fossil fuel fired steam generators are about 95% NO and 5% NO$_2$. 

2. Fuel \( NO_X \): is formed from the chemically-bound atomic nitrogen in the fuel's hydrocarbon molecules. The level of fuel \( NO_X \) emission is a function of fuel type and varies from zero (or almost zero) for natural gas (which has no bound nitrogen, or very little of it) to 60-80% of total \( NO_X \) emissions for coal.

There is no available evidence supporting the proposition that NO is a health hazard at levels found in urban air. \( NO_2 \) on the other hand, is transformed in the lungs to nitrosamines, some of which may be carcinogenic. \( NO_2 \) is known to irritate the alveoli, leading to symptoms resembling emphysema upon long term exposure to concentrations of the order of 1 ppm.

When \( NO_X \), various hydrocarbons and sunlight come together, they can initiate a complex set of reactions that produce a number of secondary pollutants known as petrochemical oxidants. Ozone (\( O_3 \)) is the most abundant of the petrochemical oxidants. Petrochemical smog, which is caused by these oxidants, is responsible for many undesirable effects on the environment, from chest constriction, coughing, shortness of breath, headache, irritation of the mucous membranes (throat, eye, nose, etc.) in people, to cracking of rubber products, damage to vegetation, reduced growth rate of certain tree species, and reduced yields of major crops such as corn, soybean, wheat and peanuts. Also, \( NO_X \) can convert to nitric acid and contribute to acid rain.

NSPS standards \( NO_X \) emissions from electric power plants are as follows:
- Gas fired: 0.2 lb/10^6 Btu (86 g/10^6 kJ)
- Oil fired: 0.3 lb/10^6 Btu (130 g/10^6 kJ)
- Coal fired: 0.6 lb/10^6 Btu (260 g/10^6 kJ)

4.4 CO and \( CO_2 \)

**Carbon monoxide (CO)** is a colorless, odorless, tasteless gas that is one of the most abundant of air pollutants. It is produced when carbonaceous fuels are burned. The amount of CO generation in combustion depends on how complete the combustion process is. If combustion is complete, all of the carbon is oxidized into carbon dioxide (\( CO_2 \)), however, if combustion is not complete, some of the carbon is not fully oxidized, and leaves the combustion in the form of CO. Thus, CO emissions increase when (i) oxygen supply is insufficient, (ii) flame temperature is low, (iii) gas residence time at high temperature is low, (iv) combustion chamber turbulence is low. Since these parameters can be tightly controlled in stationary source combustion facilities, CO emissions from these are lower than that from the transportation sector. However, with significant improvements in fuel delivery, combustion and catalytic oxidation processes, CO emissions from automotive engines have significantly reduced.

The effects of carbon monoxide exposure are reflected in the oxygen carrying capacity of the blood. In normal functioning, hemoglobin molecules in the red blood cells carry oxygen, which is exchanged for carbon dioxide in the capillaries connecting arteries to veins. CO is relatively insoluble and easily reaches the alveoli with oxygen. The CO diffuses through the alveolar walls and competes with oxygen for one of the four iron sites in the hemoglobin molecule. The affinity of the iron site for CO is about 210 times greater than for oxygen, so that this competition is extremely effective. Thus, when a hemoglobin molecule acquires a CO molecule and forms carboxyhemoglobin (COHb), the overall capacity of the blood to carry oxygen to the cells is substantially reduced. In addition, the presence of CO on one of the iron sites of a hemoglobin molecule not only removes that site as a potential carrier of an oxygen

---

3 Note that some of these requirements are opposite of what is needed for minimizing \( NO_X \) emissions
molecule but also causes the other iron sites of the molecule to hold more tightly onto the oxygen molecules they are carrying. This further reduces the amount of oxygen that the cells receive from blood. Symptoms of CO poisoning depend on the amount of hemoglobin combined with CO (i.e. COHb), which in turn depends on the concentration of CO in the air, the length of time exposed and the breathing rate. The amount of COHb in the blood is usually expressed as a percentage of the saturation level, %COHb. The amount of COHb formed in the blood can be predicted as follows:

\[
%\text{COHb} = 0.005\,[\text{CO}]^{0.85}(\text{At})^{0.63}
\]

where,  
\[
%\text{COHb} = \text{carboxyhemoglobin as a \% of saturation}
\]
\[
[\text{CO}] = \text{CO concentration in ppm}
\]
\[
\text{A} = \text{a physical activity coefficient; A}=1 \text{ for sedentary activity; A}=3 \text{ for heavy work}
\]
\[
\text{t} = \text{exposure time in minutes}
\]

This equation breaks down for large values of time (about 8 hours) corresponding to the bloodstream reaching saturation.

Individuals with heart conditions are the most sensitive to COHb since the heart must work harder in an attempt to offset the reduction in oxygen. Studies of patients with angina pectoris (a heart condition characterized by chest pain) have shown earlier than usual onset of pain during exercise when levels are as low as 2\% COHb.

The US ambient air quality standard for CO is 35 ppm. Exposed to this level of CO for one hour doing hard work (such as exercise), a person's %COHb level would reach:

\[
%\text{COHb} = 0.005\,[\text{CO}]^{0.85}(\text{At})^{0.63} = 0.005[35]^{0.85}(3\times60)^{0.63} = 2.7\%
\]

which is above the level at which health effects have been noted.

CO concentration in urban areas frequently range from 5 to 50 ppm, and on congested highways up to 100 ppm. Cigarette smoke contains more than 400 ppm of CO, and smokers have %COHb levels of 5-10\%. COHb is removed from the bloodstream when clean air is breathed. Healthy subjects can clear about half of COHb from their blood in 3-4 hours, so adverse effects are usually temporary.

The effect of CO concentration on health is given in Figure 10. National ambient air quality standards for CO and other pollutants are given in Table 4.

**Carbon dioxide (CO\textsubscript{2})** is produced as a result of burning of carbon-based fuels (hydrocarbons and coal). Of the about 186 billion tons of CO\textsubscript{2} that enter earth's atmosphere each year from all sources, only 6 billion tons are from human activity. Approximately 90 billion tons come from biologic activity in earth's oceans and another 90 billion tons from such sources as volcanoes and decaying land plants. At about 370 parts per million CO\textsubscript{2} is a minor constituent of earth's atmosphere - less than 4/100ths of 1\% of all gases present. Compared to former geologic times, earth's current atmosphere is CO\textsubscript{2} - impoverished.

Figure 10. Carbon monoxide concentration (ppm CO) versus time (minutes) and effects on health (Source: http://gexconus.com/carbon_monoxide_investigations)

Considering the vast amount of information available on the presumed effects of CO\textsubscript{2} and other greenhouse gases (GHG) on “anthropogenic global warming”, this subject will not be discussed here. For an “alternative” perspective on the “Global Warming” issue, check out:
http://www.friendsofsociety.org/
http://www.sepp.org
http://www.clearlight.com/~mziej/WVFossils/ice_ages.html
http://www.nationalcenter.org/Kyoto.html
http://www.nationalcenter.org/NPA218.html

4.5 Particulate Matter
Atmospheric particulate matter is defined to be any dispersed matter, solid or liquid, in which the individual aggregates are larger than single small molecules (about 0.0002 \(\mu\)m in diameter), but smaller than 500 \(\mu\)m.

Particulate emissions from coal-fired power plants are largely fly ash. Depending upon its origins and quality, coal contains inorganic material, such as silica (SiO\textsubscript{2}), alumina (Al\textsubscript{2}O\textsubscript{3}), titanium oxide (TiO\textsubscript{2}), iron oxides (FeO, Fe\textsubscript{2}O\textsubscript{3}), calcium oxide (CaO), magnesium oxide (MgO), sodium oxide (Na\textsubscript{2}O), potassium oxide (K\textsubscript{2}O). The inorganic material does not combust, and is left behind as ash. Part of the ash is emitted from the stack (fly ash), and the rest remains in the furnace (bottom ash). For pulverized coal furnaces, about 80% of the ash is fly ash. In addition to the fly ash, there may be some unburnt combustible material, which also is emitted as particulates.

One of the major concerns related with the control of air pollution from coal-fired power plants is the reduction of particulate emissions to acceptable levels. Depending on the characteristics of the coal fired (HHV, % ash, etc.) a pulverized coal fired 500 MW power plant produces about 15-20 tons of ash per
hour, of which 80% (12-16 t/h) that would be discharged to the atmosphere in the absence of particulate control measures.

Large particles that enter the respiratory system can be trapped by the hairs and lining of the nose. Once captured, they can be driven out by a cough or sneeze. Smaller particles that make it into the tracheobranchial system can be captured by mucous, worked back to the throat by tiny hairlike *cilia*, and removed by swallowing or spitting. Particles larger than 10 µm are quite effectively removed in the upper respiratory system by these mechanisms. Smaller particles however may escape these mechanisms and enter into the lungs and depending on their size, may or may not deposit there. Some particles are so small that they come in and go out with the air stream. Particles in the size range of 0.5 - 10 µm (most effectively between 2 - 4 µm) may enter and be deposited in the lungs by sedimentation.

Particulates in the air, especially in conjunction with SO\(_2\), have been linked to upper respiratory infections, cardiac disorders, bronchitis, asthma, pneumonia, emphysema, and the like. In addition, some particulates are toxic and carcinogenic.

The performance of particulate removal equipment is usually measured in terms of "collection efficiency". Collection efficiency is defined as the ratio of outlet loading to the inlet loading of particles, i.e. the ratio of particle loadings after and before the collector:

\[
\text{Collection efficiency } (\eta) = \left( \frac{1 - \text{outlet loading of particles}}{\text{inlet loading of particles}} \right) \times 100
\]

Thus, when the inlet loading (particulate emissions from combustion, i.e. the amount of fly ash) and the outlet loading (the allowable amount of particulate emission, controlled by environmental standards) are known, the required collection efficiency can be calculated and the collector can be designed to provide this collection efficiency. In most jurisdictions, particulate collection of 99% of better is required.

5. Environmental Control Systems

5.1. Control technologies for SO\(_2\)
Various technologies have been developed to reduce the quantities of SO\(_2\) emissions released to the atmosphere. These technologies can broadly be categorized in five groups:

1. *Precombustion technologies*: These technologies include physical and chemical coal cleaning processes. Although the physical coal cleaning processes have the potential of cleaning 65% of the sulfur from certain coals, in general they provide 2 to 30% reduction. Chemical cleaning processes on the other hand have the potential of cleaning 30-90% of the sulfur. However, these processes are expensive for commercial use.
2. *Combustion technologies*: There are several advanced combustion technologies now in demonstration or early use. One of the best-known processes is by reaction with an absorbent during combustion. This method is suitable for fluidized bed combustion (FBC). When limestone is used with these combustors, 90-95% SO\(_2\) removal is possible. They can be designed to operate at atmospheric pressure, or under pressurized conditions. A commonly used approach to control SO\(_2\) emissions in FBC is furnace sorbent injection which incorporates injection of lime into the furnace using limestone injection multistage burners (LIMB).
3. *Post-combustion technologies (or flue gas desulfurization - FGD)*: These technologies are the most widely used approaches for sulfur dioxide removal from flue gases, particularly in U.S., Japan, and West Germany. There are more than 100 different FGD technologies available today for new and retrofit applications, and the new generation of advanced flue gas desulfurization processes are gaining popularity.
in the world. These advanced systems include various technologies that are defined as "advanced wet limestone gypsum flue gas desulfurization processes".

4. **Conversion technologies**: These technologies by-pass or eliminate direct coal combustion processes altogether. In these processes coal is converted into a gas or a liquid that is then cleaned before use. These technologies are known as "integrated coal gasification combine cycle (IGCC)". Techniques are being developed to remove more than 95% of the sulfur from the coal.

5. **Coal switching**: Another alternative to SO$_2$ emission control is switching to low sulfur coals, i.e. using naturally occurring low-sulfur coals (if it is feasible). Coal switching can reduce SO$_2$ emission 20-60%. Usually coal switching is employed together with combustion or post-combustion technologies.

Flue Gas Desulfurization (FGD) systems are commonly used with PCF power plants. In FGD processes, flue gases are contacted with an absorbent medium in either an absorber or a scrubber vessel. Typically, SO$_2$ reacts with the absorbent or dissolves in the solution to produce a slurry that contains dissolved or solidified sulfur compounds. A number of dry adsorption processes also exist. At present there are a large number of FGD processes on the market, classified in a number of ways:

- by form of product (i.e. wet or dry)
- with respect to sulfur recovery and sorbent regeneration (i.e. throwaway or regenerable)
- by process (e.g. lime, limestone, dual-alkali)
- by product saleability (e.g. elemental sulfur, gypsum)
- by sponsoring companies (e.g. Wellman - Lord, Allied)

A classification of some of the most well known FGD processes, based on the form of product and sorbent regeneration, is presented in Table 5.

The basis of many of the **wet FGD processes** is contacting the flue gas with an alkaline solution or slurry in a gas absorption vessel. The vessel normally takes the form of a spray tower with either countercurrent or co-current flow. Many of the processes also remove some of the particulate matter and trace elements from flue gas. During the scrubbing process, evaporation of water cools the flue gas to slightly above its dew point. This necessitates two further processing steps. Mist eliminators are required to remove entrained droplets of scrubbing media. These generally take the form of baffles or vanes upon which the desulfurised flue gasses impinge. It is also necessary to reheat the flue gas to about 275°F to prevent condensation, fouling and corrosion in ducts, fans and stacks, to avoid a visible plume, and to improve plume dispersion.

There are both **non-regenerable and regenerable** wet scrubbing processes. Non-regenerable processes are defined as those in which the scrubbing media are disposed of as solid or liquid wastes. The liquid or sludge form of waste is the more common and requires storage in ponds. Further processing to make the waste suitable for landfill is sometimes practiced. In regenerable processes, the scrubbing medium is regenerated and reused while SO$_2$ is recovered in a form which may be processed further to sulfuric acid or elemental sulfur. Such processes are generally more complex than non-regenerable processes.

**Dry SO$_2$ removal** refers to systems in which the product of the reaction between SO$_2$ and reagent is a solid. There are three methods of achieving this. The first involves injecting a dry sorbent into the flue gas where it absorbs SO$_2$. The resulting spent sorbent and fly ash are collected in an integrated particulate removal step using baghouses or electrostatic precipitators. The sorbent is normally discarded after use. Such processes are often referred to as 'dry sorbent injection' processes. The second method uses an aqueous solution or suspension of reagent, dispersed as fine droplets, to absorb SO$_2$ from the flue gas. The droplets are dried by the heat of the flue gas and collected together with fly ash. The process is often
referred to as 'dry scrubbing' or 'semi-dry scrubbing', but is more correctly termed 'spray drying'. There are both regenerable and non-regenerable spray dryer processes. The third method involves adsorption of SO₂ onto a bed of reagent. The sorbent is normally regenerated. These processes, which can also incorporate the removal of NOₓ and fly ash, are often referred to as 'dry adsorption' processes.

Table 5. Classification of some of the well known FGD processes

<table>
<thead>
<tr>
<th>WET FGD PROCESSES</th>
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<tbody>
<tr>
<td>Non-Regenerable</td>
<td>Regenerable</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Limestone</td>
<td>Magnesium Oxide</td>
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<td></td>
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<tr>
<td>Lime</td>
<td>Wellman Lord</td>
<td></td>
<td></td>
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<tr>
<td>Alkaline Flyash</td>
<td>(Sodium Sulfide)</td>
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<tr>
<td>Chiyoda Thoroughbred</td>
<td>Citrate</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Jet-bubbling limestone)</td>
<td>Ammonia</td>
<td></td>
<td></td>
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<tr>
<td>Saarberg-Hoelter</td>
<td>Caustic soda/soda ash</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Lime gypsum)</td>
<td>Potassium Formate</td>
<td></td>
<td></td>
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<tr>
<td>Sodium Carbonate</td>
<td>Carbon adsorption-dry contacting</td>
<td></td>
<td></td>
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<tr>
<td>Dual Alkali</td>
<td>Wet contacting</td>
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<tr>
<td></td>
<td>Phosphate</td>
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<table>
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<tr>
<th>DRY FGD PROCESSES</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Non-Regenerable</td>
<td>Regenerable</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wheelabrator-Frye/</td>
<td>Aqueous Sodium (Potassium, Lithium)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rockwell Int. (Dry injection)</td>
<td>Carbonate/Spray drying</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wheelabrator-Frye/</td>
<td>Dry Adsorption</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rockwell Int. (Spray Drying)</td>
<td>Shell/UOP</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sodium Carbonate</td>
<td>Activated Carbon</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>Cat-ox</td>
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<tr>
<td></td>
<td>Manganese Oxide</td>
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<td></td>
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<tr>
<td></td>
<td>Copper Oxide</td>
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<td></td>
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<tr>
<td></td>
<td>Sodium Aluminate</td>
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The most commonly employed FGD process in North America is the limestone wet scrubbing process. The second most common process, which is very similar to the limestone process, is lime wet scrubbing. The popularity of limestone and lime FGD processes is largely due to:

1) The basic process is fairly simple and has few process steps.
2) Capital and operating costs are relatively low and reserves of limestone are fairly abundant.
3) SO₂ removal efficiencies can be as high as 95%.
4) The two-stage treatment of flue gases permits removal of SO₂ and particulates.
5) Many years of operating experience have led to a greater understanding of the basic principles of this process.
6) The process has demonstrated successful performance, especially in the removal of SO₂ from coal-fired systems.
7) Fly ash does not adversely affect the system.
8) Land necessary for waste disposal is generally available near the power plants in Canada and the US.
9) Problems with chemical scaling, plugging and erosion can be avoided by careful design and operation.
**Limestone Scrubbing: Process Description**

The removal $\text{SO}_2$ from flue gas in a limestone scrubbing process is a gas-liquid-solid mass transfer phenomenon. First, $\text{SO}_2$ must be transferred from the gas phase to the liquid phase in a scrubber. Then the sulfur species must be precipitated from the scrubbing liquor as insoluble calcium salts and disposed of.

The principles of all limestone scrubbing systems are essentially the same. When the limestone-water slurry comes in contact with flue gas containing $\text{SO}_2$, the $\text{SO}_2$ is absorbed into the slurry and reacts with limestone to form an insoluble sludge. The by-products include calcium sulfite hemihydrate ($\text{CaSO}_3 \cdot \frac{1}{2} \text{H}_2\text{O}$) and gypsum ($\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$). The latter is formed with some oxidation of the sulfite. The overall reactions can be represented as follows:

\[
\text{SO}_2 + \text{CaCO}_3 + \frac{1}{2} \text{H}_2\text{O} \rightarrow \text{CaSO}_3 - \frac{1}{2} \text{H}_2\text{O} + \text{CO}_2
\]

\[
\text{SO}_2 + \text{CaCO}_3 + \frac{1}{2} \text{O}_2 + 2\text{H}_2\text{O} \rightarrow \text{CaSO}_4 - 2\text{H}_2\text{O} + \text{CO}_2
\]

Although the overall reactions are simple, the chemistry is quite complex and not well defined. Due to the large number of solid components and ionic species in solution that are of importance, it is almost impossible to determine precisely the reaction rate and the influence of design and process variables on composition.

$\text{SO}_2$ is absorbed during a short residence time contact with the absorbent slurry. A reaction vessel or hold tank provides the necessary residence time for dissolution of the alkaline absorbent and for precipitation of the calcium sulfite and sulfate crystals. The hold tank effluent is recycled to the scrubber to absorb additional $\text{SO}_2$. Disposal of the scrubber sludge can be done in two ways: either the sludge is disposed as is in a pond (wet disposal), or it is dewatered, stabilized and then disposed in a land-fill (dry-disposal). To achieve a higher solids content after dewatering, forced oxidation can be used; this converts most of the calcium sulfite to calcium sulfate.

### 5.2. Control technologies for the emission of $\text{NO}_X$

There are several methods to reduce fuel and thermal $\text{NO}_X$ emissions. These are:

- **Low excess air firing**: This reduces the nitrogen concentration, reducing thermal $\text{NO}_X$. Also reduces oxygen concentration, reducing both fuel and thermal $\text{NO}_X$.

- **Flue Gas Recirculation (FGR)**: Reduces residence time, time of exposure to peak temperature and peak temperature. These reduce thermal $\text{NO}_X$. FGR reduces $\text{O}_2$ concentration in the burners, causing flame temperature and peak temperature zone reductions, so that the fuel residence time at peak temperature is reduced.

- **Optimum burner design (Low $\text{NO}_X$ burners)**: Fuel $\text{NO}_X$ is reduced by controlling the distribution of air and fuel within the burner. This can involve staged air combustion and staged fuel combustion.
  
  - **Staged air combustion**: air supplied to a burner is separated into two stages: primary and secondary air. In the first stage, insufficient air is supplied, causing incomplete combustion. When the initial combustion phase occurs in an oxygen deficient environment, the nitrogen released from the fuel competes with carbon and hydrogen for an insufficient amount of oxygen. Nitrogen loses the competition for oxygen, reducing the quantity of $\text{NO}$ formed. Nitrogen released from the fuel then interacts to form harmless nitrogen molecules. Also, insufficient air causes incomplete combustion, reducing peak temperature. In the second stage, sufficient air is supplied to ensure complete combustion and to cool the combustion gas.
o Staged fuel combustion: Fuel is injected into two zones of a burner. In the primary zone, a lean mixture is burned. Therefore, flame temperature is low. The remaining fuel is injected downstream of the primary zone, completing the combustion at a low peak temperature.

5.3. Control technologies for CO
Emission of CO from coal-fired power plants can be reduced by increasing combustion efficiency. This can be accomplished as follows:
- improve turbulence in the combustion chamber to ensure proper mixing of air and fuel,
- supply excess air to ensure fuel molecules meet oxygen molecules during combustion,
- increase residence time in the furnace.

5.4 Control technologies for particulates
The selection of a suitable particulate control method is done based on the desired level of collection efficiency and the particle size distribution in the gas stream. Although there are a number of methods to control particulate emissions in general, only two of these, namely fabric filters (baghouses) and electrostatic precipitators (ESP's) are employed for power plants. This limited choice is due to the inability of other types of collectors to provide the required high collection efficiencies at an economically competitive level.

Fabric Filters (Baghouses)
The most important characteristic of baghouses from the utilities' perspective is their intrinsic high collection efficiency. Properly designed baghouses can provide lower emissions than are required by current standards; thus, their cost is unaffected by the level of collection required.

Fabric filter technology is relatively new for the utility industry, coming into existence in early seventies. Today, however, baghouses represent a competitive alternative to electrostatic precipitators given the fact of significantly strengthened air quality standards, the widespread shift from high-sulfur to low sulfur coals (the latter of which produces a fly ash more difficult to precipitate), and greater regulatory attention to collection of fine particulate known to be most responsible for visibility problems. Consequently, the market for fabric filters has been increasing steadily at the expense of ESP's and other collectors.

The particulate collection efficiency of baghouses is very high for both total and fine particulate matter. They have been shown routinely capable of filtering fly ash at collection efficiencies of 99.9% on pulverized coal-fired utility boilers, of accomplishing stack opacities well below 5% (clear stack), and of achieving outlet concentrations of 0.005 lb/10^6 Btu, which is less than 20% of the allowable emissions under NSPS (New Source Performance Standards of the USA). The performance of fabric filters is generally unaffected by the type of coal or coal mixture fired, or during varying loading conditions. However, high sulfur coals present challenges to optimum baghouse operation. One of the main problems is that, they produce a different filter cake on the bags that is more difficult to remove. Also, the heavy dust cake from the high sulfur coals lead to bag life and bag suspension reliability problems. The higher acid dew point of the flue gases from high sulfur coals pose corrosion and bag damage concerns. The high intrinsic removal capability of fabric filters makes them preferable to ESP's, especially under tight emission control standards.

Design and Operation of Fabric Filters
Fabric filters capture particulates by means of a number of mechanisms including sieving, interception, impingement, diffusion, gravitational settling and electrostatic attraction. These forces hold enough particles to the cloth fibers to form a filter cake or mat which then accomplishes filtration by finer sieving as well as by previously mentioned mechanisms. Filtration process can thus be divided into three distinct
time regimes: filtration by a clean fabric, which occurs once in the life of a bag, and only for a few minutes; establishment of a residual dust cake, which occurs after many filtering and cleaning cycles, and can take a few days to several weeks or months to form; and steady state, in which (with the residual cake established on the bags) the quantity of particular matter removed during the cleaning cycle equals, on the average, the amount collected during each filtering cycle.

The most important component of baghouses is the bag itself. Bag fabric is chosen for temperature and chemical resistance, mechanical stability, and the ability to collect the desired dust cake and then permit that dust cake to be easily removed in cleaning. Fabric performance, which is rated in terms of permeability, cleanability and durability, is affected by the weave, finish, filament diameter, yarn, weight, etc. of the fabric. There are a large number of fabrics which can be used in various applications, such as acrylics, cotton, nylon, polyester, Dralon-T (polyacrylnitril), Nomex (Aromatic Polyamide), Teflon (polytetrafluoroethylen), fiberglass and combinations of these. Fiberglass fabric with teflon or some other chemical coating is most commonly used due to its ability to function at a higher temperature than the alternatives, its good resistance to chemical attack when appropriately finished, and its low cost compared to other high temperature fabrics.

Baghouses are generally classified based on the methodology used for cleaning as follows:

- Reverse gas cleaned units
- Shake/deflate cleaned units
- Pulse-jet cleaned units.

The operation of these three types of baghouses are depicted in Figure 11.

![Figure 11. Reverse gas, shake/deflate and pulse-jet baghouse designs](Sources: www.kinghome.com.cn and www.neundorfer.com)

**Reverse gas baghouses** are those that clean the filter medium by stopping the forward flow of the dirty gas and reversing part of the cleaned gas back into the compartment and through the bags. This process collapses the bags inwards and breaks up the dust cake collected inside the bags. Thus, the dislodged dust cake falls freely into the hopper. Rings are sewn into the tubular bags at nominal 4 ft spacing to prevent complete collapse, which would block the dislodged cake from falling. Occasionally, sonic generators (horns) are utilized to augment the cleaning process, which is an effective method for removing the residual dust cakes. Most utility baghouses are cleaned by reverse gas method. Bag life, an important concern for baghouse operations, is about four years for reverse gas bags.

The bags that are used on reverse gas baghouses fall into two size groups: nominally 8 in diameter bags or 12 in diameter bags. These diameters represent the optimum size that can be cut from a bolt of
fiberglass cloth. Bag height is determined by using a nominal 30/1 length to diameter ratio; however, with 12 in. diameter bag, 35/1 ratio is also used. Thus, 8 in diameter bags are 20-22 ft long, whereas 12 in diameter bags can be 30-35 ft long.

Shake/deflate baghouses utilize non-ringed bags and, similar to reverse gas units, the particulates are collected inside the bags, which are deflated at certain intervals by reversing a small quantity of clean gas back into the compartments. The deflated (relaxed) bags are then shaken at the top for 10-30 seconds with a frequency normally less than five cycles per second and an amplitude of 1-3 inches from the rest position. This motion following deflation of the bag dislodges the dust cake, which then falls into the hopper.

Pulse jet baghouses collect the particulates on the outside of the bags and are cleaned by periodically blasting a jet of high pressure air down inside of the bag which is supported interiorly by a wire frame. In the filtering mode, the bag is collapsed on the frame because of the pressure of the gas being cleaned on the outside. The air jet inflates the bag momentarily loosening the dust cake, which consequently falls off. Pulse-jet baghouses can accommodate a higher specific velocity of filtration (air-to-cloth ratio) than the other types, thus they require less cloth area. However, this cleaning method is harsh on bags, and reduces bag life and reliability. Another disadvantage associated with the pulse jet baghouses is the complexity of the system. Pulse-jet cleaning requires air compressors, compressed air piping and air drying systems, manifold systems, venturi tubes above each bag, metal support cages inside bags and other miscellaneous equipment, raising maintenance and dependability concerns. Moreover, since the bags used in pulse-jet cleaning are smaller than those in reverse air units, more number of bags are required. As a result of all of these reasons, some of the perceived advantages of operation at higher A/C ratios are lost, and consequently pulse-jet baghouses are not preferred in the utility industry.

In utility baghouses, gas cleaning is conducted in cycles initiated by a predetermined pressure drop or time interval, and each compartment is sequentially removed from service and isolated before cleaning can take place. If all baghouse compartments are cleaned one after another in rapid succession when a predetermined pressure drop is reached, or a predetermined time interval elapses, this is called intermittent, or batch cleaning. If they are cleaned one after another in constant, equally spaced time increments, this is called timed cleaning. Some units always have one compartment or more off line and being cleaned. This is called continuous cleaning. However, continuous cleaning is also conducted sequentially, and 25-30 minutes may elapse before every compartment is cleaned.

The maximum number of bags per compartment is specified to maintain the minimum difference between the gross and net A/C ratios. While some baghouses have compartments containing 700 to 800 bags, others may have less than one hundred.

In sizing and design of baghouses, two of the most critical parameters are the air-to-cloth ratio, and the pressure drop across the fabric and across the baghouse unit (flange-to-flange).

The air-to-cloth (A/C) ratio, also known as the superficial filtering velocity, is defined as the actual volumetric gas flow rate, Q, divided by the filtering area, A. Thus the A/C ratio, to a large extent, determines the size of the baghouse needed for a certain application. The A/C ratio is generally expressed using the unit of feet per minute following from its definition:

\[
A/C = \frac{Q}{A} = \frac{\text{ft}^3/\text{min}}{\text{ft}^2} = \text{ft/min}
\]

Choosing the appropriate A/C ratio for a certain application is critical since it affects the performance, operation and maintenance of the unit. A high A/C ratio, i.e. a small filtering area, results in a high
pressure drop, which increases the operating (energy) costs. Also, the particulates penetrate deeper in the filter material due to their higher initial velocity, making the bag more difficult to clean. Excessively high pressure drops may foul the bags irreversibly, requiring replacement by new bags.

A/C ratio can be defined using two different bases for the filter area. "Gross A/C ratio" is based on the total filtering area present in the unit, whereas "Net A/C ratio" is based on the actual filtering area in service at any point in time, which accounts for one compartment in the cleaning mode and another shutdown for maintenance.

A/C ratios suitable for reverse air, shake/deflate and pulse air baghouses are different from each other. Typical net A/C values are:
- Reverse gas: about 2,
- Shake/deflate: 2.5 - 3.5
- Pulse jet: 5-6.

Electrostatic Precipitators (ESP's)
Since they were introduced to the utility industry in the 1920's, ESP's have been a widely used means of controlling fly ash emissions from coal-fired boilers. Various designs of ESP's are used. Cold-side ESP's, which are located downstream of the air preheaters, are generally utilized with high sulfur coals, whereas hot-side ESP's, located upstream of the air preheaters, are more suitable for low sulfur coals which produce high resistivity ashes. From the mechanical design point of view, ESP's can incorporate weighted wire discharge electrodes (the American design) or the rigid frame structure (the European design).

Although a great amount of work has been done on the design and performance of ESP's, there are no standard or generally accepted procedures due to the large number of parameters affecting ESP performance and the complexity of their interactions. Moreover, a great portion of the design data and information are held by manufacturers as proprietary.

Design and Operation of ESP's
Electrostatic precipitators operate on the principle of electrostatic attraction between substances of opposite polarity. An electrostatic precipitator removes suspended particles from the gasses by exposing the particles to a high voltage electric field (ranging from 30 to 100 kV) produced by a discharge electrode and a grounded collection surface. The collection surface can be in the form of plates or tubes within a gas tight enclosure, with discharge electrodes hanging exactly midway between the plates, or in the centerline of the tubes. As the particulate-laden flue gas flows through this intense electric field, carrier gasses become ionized and in turn charge the entrained particles. The negatively charged particles, still in the presence of the electrostatic field, migrate to the collection surface, which has an opposite (positive) charge. Particles that deposit on the collection surface lose their charge and the agglomerated dust is shaken loose by rappers or other means. The dust falls into a hopper where it is collected.

ESP's are generally categorized based on their mechanical design (weighted wire or rigid frame) and their location relative to the air preheater (before or after the preheater, i.e. hot or cold side). The weighted wire ESP's, also known as the American type, incorporate free hanging wire electrodes approximately 1/8 in in

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4 Hot-side ESP's are not commonly specified because of the many operational problems encountered. Hot-side ESP's were largely popular in mid-seventies because architect-engineers and vendors felt they were more economical; however, because of all the problems many have been retrofitted to become cold-side ESP's.
diameter supported by a rack on top and held taut by a weight at the bottom. Rigid frame ESP's, also known as European Design ESP's, utilize rigid support frames for the electrodes which may be coiled spring wires, serrated strips, needle points mounted on supporting strips and the like. The heavy framework provides greater strength and reduces breakage of the electrodes, which are larger in diameter than those of the weighted wire designs. Because of the larger diameter, the corona starting voltage is higher, which has the disadvantage of yielding a lower efficiency for a given amount of plate area. Due to their sturdier structure, rigid frame ESP's have longer electrode life and are more reliable than weighted wire ESP's. Consequently, their capital costs are higher and operating costs lower.

ESP's located downstream of the air preheater are referred to as Cold-Side ESP's. They typically operate in the 130-180°C (270-350°F) range. Hot-side ESP's are located between the boiler and air preheater, thus the flue gas temperature is higher than 230°C (450°F), generally in the 300-480°C (600-900°F) range.

One of the most important factors related with coal quality that affect ESP performance is the resistivity of fly ash \(^5\). Experience has shown that resistivity of coal ash particles in the flue gas should be between 10\(^7\) and 10\(^{11}\) ohm-cm for practical operation. These are, in fact, the outer acceptable limits, because if the resistivity is as high as 2 x 10\(^{10}\) ohm-cm or higher, ESP collection efficiency decreases and very large units are needed to meet emission requirements. This decrease of efficiency is due to back corona which is caused by an electrical breakdown in high resistivity dusts generating positive ions within the dust layer which accelerate toward the negative (discharge) electrode. This occurs when high resistivity particles migrate to the collecting surface but fail to dissipate their charge, causing a high potential gradient in the dust layer on the surface of the plate. This layer disrupts the electrical field that induces migration, and repels particles of like charge attempting to migrate to the collecting surface. If the potential gradient across the layer gets sufficiently high, it promotes current conduction of diametrically opposed polarity of the discharge electrode. Therefore, back-corona is extremely detrimental to ESP performance. On the other hand, particles with less than 10\(^7\) ohm-cm resistivity tend to sweep out of the precipitator without depositing on the collector plates, but such ash resistivities are rarely encountered.

Fly ash resistivity depends primarily on the sulfur content of the coal ash, flue gas temperature and moisture, and such ash constituents as sodium, potassium, alumina, silica and iron oxide. Ash resistivity is inversely proportional with the concentration of sulfur trioxide and water in the flue gas, and sodium, potassium and carbon in the ash. It is directly proportional with the ash constituents of calcium, magnesium, alumina and silica. Peak ash resistivities occur between 250 and 450°F, depending on ash characteristics. Above 450-550°F, ash resistivity is inversely proportional with temperature, whereas below 250-300°F, it is directly proportional with temperature. This relationship between ash resistivity and temperature has led to the development of hot-side ESP's for collecting high resistivity fly ashes from low sulfur coals. Resistivity of most ashes is low enough (< 2 x 10\(^{10}\) ohm-cm) at temperatures above 600-800°F for electrostatic precipitation. The major disadvantage of hot-side ESP's is the great increase in precipitator size to handle the increased gas volume and still maintain a low flow rate for adequate residence time for particle charging and collection. Due to their increased size, capital cost of hot-side ESP's are much higher than the capital cost of cold side precipitators.

To precipitate high resistivity fly ashes, there are also some other methods that are less costly than utilizing hot-side ESP's. These include improved operation procedures; chemical conditioning of the flue gas using SO\(_3\), NH\(_3\), TEA (triethylamine), precharging and pulse energization.

\(^5\) The resistivity of fly ash can be determined experimentally in a laboratory or by in situ measurements. Fly ash resistivity can also be predicted based on ash chemistry using analytical methods and correlations.
One of the most important parameters in the design of an ESP is the total collection area required to meet emission constraints. The required collection area is determined based on the characteristics of the given coal and the targeted collection efficiency. Target collection efficiency is determined based on the amount of fly ash generated and the particulate matter emission standards, which dictate the maximum permissible level of emissions from a power plant. Particulate matter emission standards are expressed in terms of the allowable weight of particulate matter emission per unit of heat input to the boiler, i.e. lb ash/10^6 Btu. Thus, the target collection efficiency can be determined as follows:

\[
TCEFF = 1 - \frac{EMCON}{ASHF \times FLYAFR \times 10^6 / HHV} \times 100
\]

where,
- \( TCEFF \) = target collection efficiency, %
- \( EMCON \) = emission constraint, lb ash/10^6 Btu fired (most recent NSPS requires that particulate emissions will be less than 0.03 lb/10^6 Btu heat input
- \( ASHF \) = weight fraction of ash in boiler feed coal, decimal
- \( FLYAFR \) = fraction of ASH which enters the flue gas, decimal (This is between 0.7-0.8 for pulverized coal firing, however for the design of fly ash collector systems a more conservative figure, such as 0.95 is warranted).
- \( HHV \) = higher heating value of boiler feed coal, Btu/lb.

Once the target collection efficiency is determined, it is necessary to calculate the ESP area that can provide this efficiency. There are a number of ESP sizing methodologies, however most of these methodologies are highly complex or proprietary. Therefore, the simplified empirical relationship by Hesketh\(^6\) for coal fired boiler systems is given here to estimate the SCA:

\[
SCA = 433 \times S^{-0.59} \times (100 - TCEFF)^{-0.24}
\]

where,
- \( SCA \) = specific collection area, ft\(^2\)/1000 acfm
- \( S \) = % by weight of sulfur in coal
- \( TCEFF \) = collection efficiency, %.

This empirical equation is designed for the high 99% collection efficiency range. It applies to properly designed, operated and maintained systems. It is based on standard DC charging and collecting, and does not address possible advantages of pulse powering options. It is assumed that problems such as gas sneakage, rapping re-entrainment, back corona and electrohydrodynamics are not significant. It should also be noted that Hesketh's equation can be used for American design hot and cold side ESP's, but is not suitable for rigid frame ESP's due to the lower intrinsic collection efficiency of rigid frame designs for a given plate area (as mentioned above).

Thus, for a specific coal represented by its sulfur content, and a specific collection efficiency requirement, once the SCA is calculated, the total collector plate area is determined by multiplying the SCA by the flue gas flow rate:

\[
ESPCA = SCA \times \frac{FG}{1,000}
\]

Flue gas flow rate can be calculated using the equation given below. This equation estimates flue gas flow rate at 300°F, which is suitable for cold-side ESP's. For hot-side ESP's, which operate in the 600-900°F range, flue gas flow rate determined from this equation should be corrected for the higher temperature. This can be accomplished by treating the flue gas as an ideal gas. Thus:

\[ FG_T = \left( \frac{FG_{300}}{300 + 460} \right) \times (T + 460) \]

where, \( FG_T \) = flue gas flow rate at any temperature \( T \) (°F), acfm,  
\( FG_{300} \) = flue gas flow rate at 300°F, acfm.

**Flue Gas Flow Rate:**

Flue gas flow rate is a parameter that is needed in sizing air pollution control equipment. It can be calculated by carrying out the combustion calculations, or an approximate value can be calculated using the following equation:

\[ FG = \left\{ 0.253 + 0.0505 \times [4.76 \times EX + 7.63 \times MA \times (1 + EX)] + \frac{513 \times MC}{HVMAF} \right\} \times MW \times NHR \times (1 + AHL) \]

where, \( FG \) = flue gas flow rate, acfm at 330°F  
\( EX \) = amount of excess air, decimal  
\( MA \) = weight fraction of moisture in air, decimal  
\( MC \) = weight fraction of moisture in coal, decimal  
\( HVMAF \) = heating value of moisture and ash free coal, Btu/lb  
\( MW \) = capacity of power plant, MW (electrical)  
\( NHR \) = net heat rate of power plant, Btu/kWh  
\( AHL \) = air heater leakage, expressed as a decimal

Using 0.01 for \( MA \) as a typical value, the equation becomes:

\[ FG = \left\{ 0.253 + 0.0505 \times [4.76 \times EX + 0.0763 \times (1 + EX)] + \frac{513 \times MC}{HVMAF} \right\} \times MW \times NHR \times (1 + AHL) \]

Heating value of moisture and ash free coal can be calculated as follows:

\[ HVMAF = HHV/(1 - MC - ASHC) \]

where, \( HHV \) = higher heating value of coal, Btu/lb
\( ASHC \) = weight fraction of ash in coal, decimal
\( MC \) = as defined above
6. Ash and FGD Sludge Disposal Systems

A typical coal fired power plant employing ESP's or baghouses for particulate control and limestone FGD for SO\textsubscript{2} control produces three types of waste: (1) bottom ash (including slag), (2) fly ash, (3) FGD sludge. There are two alternatives for dealing with these wastes: (1) utilization, (2) disposal.

There are two basic types of coal combustion waste\textsuperscript{7} disposal systems: wet (ponding), and dry (landfilling). In wet disposal systems the waste is transported to and deposited in the disposal site in a fluid state; whereas in dry disposal systems, the waste is handled and disposed of as a solid material. In the past, wet disposal was preferred over dry disposal; however; at present, utilities show a rising preference for dry disposal, with some converting existing ponds to landfills for lack of additional space.

Generally, in power plants that employ FGD systems that produce a sludge (i.e. limestone scrubbing), ash is disposed together with the sludge. However, if there is no SO\textsubscript{2} control, then only the disposal of fly and bottom ash is required.

Solid waste handling and disposal is regulated by a number of acts which address different types of possible environmental impacts, such as surface water contamination, ground-water contamination, waste stability/consolidation, fugitive air emissions and contamination of marine environment.

6.1. Utilization of Ash and FGD Sludge

An alternative to disposal of coal ash is utilization. A wide variety of uses have been found for power plant ash, including:

- Fill and cover material
- Soil improvement
- Roadways and pavements
- Drainage
- Pozzolan (a type of ash used for mortar or cement that sets under water)
- Structural products
- Lightweight aggregate
- Grout and mortar
- Metal extraction

Pozzolan applications have historically represented the largest outlet for flyash, but the other areas are utilizing increasing amounts of coal ash as natural resources continue to decrease in supply or availability. The use of fly ash as a partial cement replacement has a number of economic and technical benefits since ultimate strength is increased as is durability and drying shrinkage is reduced. Fly ash also stands up well in sea salt, therefore it could find applications in offshore structures.

The throw-away type FGD processes, such as lime and limestone scrubbing which are the most commonly used in the utility industry, produce voluminous waste products in the form of sludge. It is therefore needed to further process the sludge to be able to produce a useful by-product. The potential uses of FGD sludge by-products include the following:

- in the wallboard products industry substituting for naturally occurring gypsum,
- as a cement retarder in cement production,
- as a soil amendment in agriculture,

\textsuperscript{7} "Coal combustion waste" includes fly ash, bottom ash and FGD sludge.
- as a base for roads, driveways and parking lots,
- in the construction of liners for wastewater ponds,
- in the formation of artificial reefs in the ocean.

6.2. Disposal of Ash

Ash disposal systems can be classified as wet, dry, or a combination of wet and dry.

Wet ash disposal systems hydraulically transport ash from the power plant to an ash disposal pond or ponds which function as large-scale sedimentation basins. Bottom ash and fly ash can be placed in the same pond, in different ponds, or sluiced to different areas of the same pond to enhance ash segregation. In general, bottom ash, economizer and air heater ash are transported by the same sluicing system. Fly ash is pneumatically transported from particulate removal devices and collected in a central area for sluicing. Slurried ash, which typically has 10-15% solids by weight, is transported to the disposal area by pipeline. Transport distances from the plant to the disposal area are commonly less than one mile due to the difficulties and expense of slurry transport over long distances.

Ash entering the disposal pond settles, leaving a supernatant. The supernatant can be treated and discharged, recycled, evaporated, or impounded. Local climate, receiving stream water quality, and environmental regulations strongly influence supernatant disposal.

Wet site construction requires the building of an embankment, pond excavation, or a combination of these methods. The possibility of groundwater pollution by ash leachates lead to regulations requiring the siting of ash basins in impermeable soils or the installation of liners. Exposed embankments should be protected from erosion by vegetation or by rip-rap (loose stone). Site closure normally involves placement of a soil cover over the pond surface and diversion of surface water from the site.

Dry ash disposal systems essentially entail the landfilling of ash conditioned with a sufficient amount of water to aid placement. Bottom ash, usually hydraulically transported from the boiler bottom to a dewatering bin or pond, is commonly transported separately from fly ash. Fly ash is collected in storage silos for transport to the disposal site. Bottom ash is relatively inert and has good porosity. As such, it is sometimes used to construct drainage blankets and filters. Fly ash can be delivered to disposal areas and spread with conventional earth moving equipment. Depending on economic considerations and plans for the future use of the site after closure, the ash can be compacted. If compacted, the required storage volume is reduced accordingly and the site can be used for developments such as housing, parks, golf courses and industrial sites since compacted ash is capable of supporting moderate foundation loads. Ash stored in this manner also usually retains its chemical properties. Thus, dry disposal provides ash stockpiles for future uses, such as metal and mineral extraction or construction additives. It can also serve as a source of material for projects requiring structural fill material.

While the transportation of dry ash is most commonly done by truck, it can also be moved by rail, belt or pneumatic conveyors. As ash arrives at the site, it is usually dumped in piles and spread in layers. It may be compacted to reduce the overall volume required or as part of the site development plan. The addition of water at the site is sometimes necessary to achieve sufficient moisture content for dust control and proper compaction. The amount of water required depends upon local weather, ash characteristics, and water added prior to transport.

Several combinations of wet and dry disposal systems are possible, depending upon ash characteristics and in-plant collection and handling systems. For example, a combination system might involve pumping the ash slurry to a pond located close to the power plant site. After dewatering, the coal ash can be excavated and transported to a dry site for final disposal. Another example of a combination system involves the
handling of very reactive fly ash. One method of handling reactive ash is to transport it dry to the disposal site. At the disposal site fly ash is mixed with water and deposited into ponds where it cures and hardens.

6.3. Disposal of FGD sludge

FGD sludge disposal systems can be classified as wet or dry. In all wet FGD sludge disposal systems, the sludge is transported and deposited in the final disposal site in a fluid state. Wet disposal systems are applicable to all lime, limestone and alkaline fly ash wet scrubbing systems. Since the scrubbing system produces the sludge as a solid/liquid slurry, the waste is already in a form amenable to wet disposal. Co-disposal of sluiced ash and FGD sludge in the same pond is also practiced. The degree of sludge processing may vary considerably. In some systems, the scrubber bleed stream is piped directly to the disposal pond, with supernatant returned to the scrubber system for make-up water. In other systems, the bleed stream is treated prior to final ponding. Some systems use thickeners and/or interim settling ponds to reduce water content, thereby reducing the size of the final disposal pond, reducing water balance problems at the pond, and minimizing costs.

Climate conditions, regulatory requirements, and/or site-related constraints may make wet disposal undesirable or uneconomic. In areas of high precipitation, excess water in the pond may make wet disposal infeasible, particularly if supernatant discharge is not permissible. Alternately in arid regions, excessive evaporative losses from a large pond may be unacceptable where water is to be conserved in the system. Regulatory constraints, such as the requirement for a pond liner, may make dry disposal preferable in some cases. The most common constraint is the absence of suitable land area of sufficient size in close proximity to the plant for pond or impoundment construction. Locations suitable for impoundments are generally less common than those suitable for landfills.

In dry FGD sludge disposal systems, the sludge is processed so that it may be deposited in the final disposal site as a solid material, or as a material that will solidify rapidly enough that dams or dikes are not required. In most dry disposal systems, the sludge is processed sufficiently so that it can be handled as a solid material immediately after processing. The dewatered sludge is generally transported to the landfill site by trucks, rail or belt conveyors, and for distances longer than 10-15 mi, rail is generally more economical.

Most dry systems include both dewatering and blending (generally with fly ash) processes. Dewatering and blending of the FGD sludge with ash are carried out to:
- reduce sludge transport and disposal volume as well as land area requirements,
- permit the sludge to be handled and disposed of as a solid rather than a liquid,
- reduce the moisture content of the sludge so that the final product has the structural characteristics that would be suitable for landfill,
- reduce the potential for release of sludge leachates from disposed material.

Two approaches are used for dry disposal of ash and FGD sludge. These are stabilization and fixation. Stabilization is simply blending fly ash with dewatered FGD sludge, which results in 75 - 80% solids content in the resulting sludge. Fixation (sometimes termed chemical treatment), on the other hand, is a type of stabilization, which involves the addition of reagents causing chemical reactions with the sludge, which results in a cementious structure. Some of the most common fixation processes employ fly ash/lime, blast furnace slag and portland cement as the fixating agents.