CLEANER PRODUCTION GUIDELINES IN THERMAL POWER PLANT

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India has the world’s fifth-largest electricity generation capacity and demand is expected to surge in the coming years owing to growth in the economy. According to the Ministry of Power, the total installed capacity of power is 181,558 MW in India. Out of this, state sector, Central sector and private sector contribute 83,314 MW, 56,573 MW and 41,672 MW, respectively. The electricity generation target for the year 2010–2011 was fixed at 830.757 billion units (BU) and, in 2009–10; electricity generation was at 771.6 BUs of power, according to the ministry.

India has abundant sources of power production. Thermal power in India accounts for roughly two-thirds of the power generated in India which includes gas, liquid fuel and coal. Reserves for thermal power generation include 59 billion tonnes of mineable coal, 775 million metric tonnes of oil reserves and natural gas reserves of 1,074 billion cubic metres. Other prominent and fast-growing sources of power are hydro, wind, solar, nuclear, biomass and industrial waste, etc. Presently, out of the total power being generated, 54.8% is coal based, 9.75% is gas based and 0.66% is oil based, hydro contributes for 21% of power, while nuclear production is 2.63% and the rest 11.1% is collectively produced by renewable energy sources such as small hydro project, biomass gasifier, biomass power, urban and industrial waste power and wind energy.

(Ref: http://www.investindia.gov.in/?q(power-sector)

A coal based thermal power plant converts the chemical energy of the coal into electrical energy. This is achieved by raising the steam in the boilers, expanding it through the turbine and coupling the turbines to the generators which converts mechanical energy into electrical energy.

General Description of Industry Activities

Thermal power plants burn fossil fuels or biomass to generate electrical energy and heat. Mechanical power is produced by a heat engine, which transforms thermal energy from combustion of a fossil fuel into rotational energy. A generator converts that mechanical energy into electrical energy by creating relative motion between a magnetic field and a conductor. Figure 1 is a generalized flow diagram of a boiler-based thermal power plant and its associated
operations. Not all thermal energy can be transformed to mechanical power, according to the second law of thermodynamics.

Therefore, thermal power plants also produce low-temperature heat. If no use is found for the heat, it is lost to the environment. If reject heat is employed as useful heat (e.g., for industrial processes or district heating), the power plant is referred to as a cogeneration power plant or CHP (combined heat-and-power) plant.

**Types of Thermal power plants**

Thermal power plants can be divided based on the type of combustion or gasification: boilers, internal reciprocating engines, and combustion turbines. In addition, combined-cycle and cogeneration systems increase efficiency by utilizing heat lost by conventional combustion systems. The type of system is chosen based on the loads, the availability of fuels, and the energy requirements of the electric power generation facility. Other ancillary processes, such as coal processing and pollution control, must also be performed to support the generation of electricity. The following subsections describe each system and then discuss ancillary processes at the facility (USEPA 1997).

**Boilers (Steam Turbines)**

Conventional steam-producing thermal power plants generate electricity through a series of energy conversion stages: fuel is burned in boilers to convert water to high-pressure steam, which is then used to drive a steam turbine to generate electricity. Heat for the system is usually provided by the combustion of coal, natural gas, oil, or biomass as well as other types of waste or recovered fuel. High-temperature, high-pressure steam is generated in the boiler and then enters the steam turbine. At the other end of the steam turbine is the condenser, which is maintained at a low temperature and pressure. Steam rushing from the high pressure boiler to the low-pressure condenser drives the turbine blades, which powers the electric generator.
Low-pressure steam exiting the turbine enters the condenser shell and is condensed on the condenser tubes, which are maintained at a low temperature by the flow of cooling water. As the steam is cooled to condensate, the condensate is transported by the boiler feed water system back to the boiler, where it is used again. A constant flow of low-temperature cooling water in the condenser tubes is required to keep the condenser shell (steam side) at proper pressure and to ensure efficient electricity generation. Through the condensing process, the cooling water is warmed. If the cooling system is an open or a once-through system, this warm water is released back to the source water body.

In a closed system, the warm water is cooled by recirculation through cooling towers, lakes, or ponds, where the heat is released into the air through evaporation and/or sensible heat transfer. If a recirculating cooling system is used, only a relatively small amount of makeup water is required to offset the evaporative losses and cooling tower blowdown that must be discharged periodically to control the build-up of solids. A recirculating system uses about one twentieth the water of a once-through system. Steam turbines typically have a thermal efficiency of about 35 percent, meaning that 35 percent of the heat of combustion is transformed into electricity. The remaining 65 percent of the heat either goes up the stack (typically 10 percent) or is discharged with the condenser cooling water (typically 55 percent).

Coal and lignite are the most common fuels in thermal power plants although heavy fuel oil is also used. Coal-fired steam generation systems are designed to use pulverized coal or crushed coal. Several types of coal-fired steam generators are in use, and are generally classified based on the characteristics of the coal fed to the burners and the mode of burning the coal. In fluidized-bed combustors, fuel materials are forced by gas into a state of buoyancy. The gas cushion between the solids allows the particles to move freely, thus flowing like a liquid. By using this technology, SO2 and NOX emissions are reduced because an SO2 sorbent, such as limestone, can be used efficiently. Also, because the operating temperature is low, the amount of NOX gases formed is lower than those produced using conventional technology.
Natural gas and liquid fuels are usually transported to thermal power plants via pipelines. Coal and biomass fuels can be transported by rail, barge, or truck. In some cases, coal is mixed with water to form slurry that can be pumped to the thermal power plant in a pipeline. Once coal arrives at the plant, it is unloaded to storage or directly to the stoker or hopper. In transporting coal during warmer months and in dry climates, dust suppression may be necessary.

Coal may be cleaned and prepared before being either crushed or pulverized. Impurities in coal such as ash, metals, silica, and sulfur can cause boiler fouling and slagging. Coal cleaning can be used to reduce sulfur in the coal to meet sulfur dioxide (SO2) emissions regulations and also reduce ash content and the amount of heavy metals. Cleaning the coal is costly, but the cost can be at least partially offset by an increase in fuel efficiency, reduced emission control requirements, and lower waste management costs. Coal cleaning is typically performed at the mine by using gravity concentration, flotation, or dewatering methods.

Coal is transported from the coal bunker or silo to be crushed, ground, and dried further before it is fired in the burner or combustion system. Many mechanisms can be used to grind the coal and prepare it for firing. Pulverizers, cyclones, and stokers are all used to grind and dry the coal. Increasing the coal’s particle surface area and decreasing its moisture content greatly boosting its heating capacity. Once prepared, the coal is transported within the plant to the combustion system. Devices at the bottom of the boilers catch ash and/or slag.

**Reciprocating Engines**

Internal combustion engines convert the chemical energy of fuels (typically diesel fuel or heavy fuel oil) into mechanical energy in a design similar to a truck engine, and the mechanical energy is used to turn a generator. Two types of engines normally used: the medium-speed, four-stroke trunk piston engine and the low-speed, two-stroke crosshead engine. Both types of engine operate on the air-standard diesel thermodynamic cycle. Air is drawn or forced into a cylinder and is compressed by a piston. Fuel is injected into the cylinder and is ignited by the heat of the compression of the air. The burning mixture of fuel and air expands, pushing the piston. The products of combustion are then removed from the cylinder, completing the cycle.
The exhaust gases from an engine are affected by the load profile of the prime mover; ambient conditions such as air humidity and temperature; fuel oil quality, such as sulfur content, nitrogen content, viscosity, ignition ability, density, and ash content; and site conditions and the auxiliary equipment associated with the prime mover, such as cooling properties and exhaust gas back pressure. The engine parameters that affect NOX emissions are fuel injection in terms of timing, duration, and atomization; combustion air conditions, which are affected by valve timing, the charge air system, and charge air cooling before cylinders; and the combustion process, which is affected by air and fuel mixing, combustion chamber design, and the compression ratio.

The particulate matter emissions are dependent on the general conditions of the engine, especially the fuel injection system and its maintenance, in addition to the ash content of the fuel, which is in the range 0.05–0.2%. SOx emissions are directly dependent on the sulfur content of the fuel. Fuel oil may contain as little as 0.3% sulfur and, in some cases, up to 5% sulfur.

Diesel engines are fuel flexible and can use fuels such as diesel oil, heavy fuel oil, natural gas, crude oil, bio-fuels (such as palm oil, etc.) and emulsified fuels (such as Orimulsion, etc.). Typical electrical efficiencies in single mode are typically ranging from 40 % for the medium speed engines up to about 50 % for large engines and even higher efficiencies in combined cycle mode. Total efficiency in CHP (Combined Heat and Power) is typically in liquid operation up to 60 – 80 % and in gas mode even higher dependent on the application. The heat to power ratio is typically 0.5 to 1.3 in CHP applications, dependent on the application.

**Lean Burn Gas Engines**

Typical electrical efficiencies for bigger stationary medium speed engines in single mode are typically 40 – 47 % and up to close to 50 % in combined cycle mode. Total efficiency in CHP facilities is typically up to 90 % dependent on the application. The heat to power ratios is typically 0.5 to 1.3 in CHP applications, dependent on the application.
Spark Ignition (SG)

Often a spark ignited gas-otto engine works according to the lean burn concept meaning that a lean mixture of combustion air and fuel is used in the cylinder (e.g., much more air than needed for the combustion). In order to stabilize the ignition and combustion of the lean mixture, in bigger engine types a pre-chamber with a richer air/fuel mixture is used. The ignition is initiated with a spark plug or some other device located in the prechamber, resulting in a high-energy ignition source for the main fuel charge in the cylinder.

The most important parameter governing the rate of NOx formation in internal combustion engines is the combustion temperature; the higher the temperature the higher the NOx content of the exhaust gases. One method is to lower the fuel/air ratio, the same specific heat quantity released by the combustion of the fuel is then used to heat up a larger mass of exhaust gases, resulting in a lower maximum combustion temperature. This method low fuel/air ratio is called lean burn and it reduces NOx effectively. The spark-ignited lean-burn engine has therefore low NOx emissions. This is a pure gas engine; it operates only on gaseous fuels.

Dual fuel engines (DF)

Some DF engine types are fuel versatile, these can be run on low pressure natural gas or liquid fuels such as diesel oil (as back-up fuel, etc.), heavy fuel oil, etc. This engine type can operate at full load in both fuel modes. Dual Fuel (DF) engines can also be designed to work in gas mode only with a pilot liquid fuel used for ignition of the gas.

Combustion Turbines

Gas turbine systems operate in a manner similar to steam turbine systems except that combustion gases are used to turn the turbine blades instead of steam. In addition to the electric generator, the turbine also drives a rotating compressor to pressurize the air, which is then mixed with either gas or liquid fuel in a combustion chamber. The greater the compression, the higher the temperature and the efficiency that can be achieved in a gas turbine.
Higher temperatures, however, typically lead to increases in NOX emissions. Exhaust gases are emitted to the atmosphere from the turbine. Unlike a steam turbine system, gas turbine systems do not have boilers or a steam supply, condensers, or a waste heat disposal system. Therefore, capital costs are much lower for a gas turbine system than for a steam system.

In electrical power applications, gas turbines are often used for peaking duty, where rapid startup and short runs are needed. Most installed simple gas turbines with no controls have only a 20- to 30-percent efficiency.

**Combined Cycle**

Combined-cycle generation is a configuration using both gas turbines and steam generators. In a combined-cycle gas turbine (CCGT), the hot exhaust gases of a gas turbine are used to provide all, or a portion of, the heat source for the boiler, which produces steam for the steam generator turbine. This combination increases the thermal efficiency to approximately 50 - 60 percent. Combined-cycle systems may have multiple gas turbines driving one steam turbine. Combined-cycle systems with diesel engines and steam generators are also sometimes used.

In addition, integrated coal gasification combined-cycle (IGCC) units are emerging technologies. In an IGCC system, coal gas is manufactured and cleaned in a "gasifier" under pressure, thereby reducing emissions and particulates. The coal gas then is combusted in a CCGT generation system.
Cogeneration

Cogeneration is the merging of a system designed to produce electric power and a system used for producing industrial heat and steam and/or municipal heating. This system is a more efficient way of using energy inputs and allows the recovery of otherwise wasted thermal energy for use in an industrial process. Cogeneration technologies are classified as "topping cycle" and "bottoming cycle" systems, depending on whether electrical (topping cycle) or thermal (bottoming cycle) energy is derived first. Most cogeneration systems use a topping cycle.

Figure 1: Generalized Flow Diagram of a Thermal power plant and Associated Operations

Environmental issues in Thermal Power plant:

- Air emissions
- Energy efficiency and Greenhouse Gas emissions
- Water consumption and aquatic habitat alteration
- Effluents
Solid wastes
- Hazardous materials and oil
- Noise

**Air Emissions**

The primary emissions to air from the combustion of fossil fuels or biomass are sulfur dioxide (SO2), nitrogen oxides (NOX), particulate matter (PM), carbon monoxide (CO), and greenhouse gases, such as carbon dioxide (CO2). Depending on the fuel type and quality, mainly waste fuels or solid fuels, other substances such as heavy metals (i.e., mercury, arsenic, cadmium, vanadium, nickel, etc), halide compounds (including hydrogen fluoride), unburned hydrocarbons and other volatile organic compounds (VOCs) may be emitted in smaller quantities, but may have a significant influence on the environment due to their toxicity and/or persistence. Sulfur dioxide and nitrogen oxide are also implicated in long-range and trans-boundary acid deposition.

The amount and nature of air emissions depends on factors such as the fuel (e.g., coal, fuel oil, natural gas, or biomass), the type and design of the combustion unit (e.g., reciprocating engines, combustion turbines, or boilers), operating practices, emission control measures (e.g., primary combustion control, secondary flue gas treatment), and the overall system efficiency. For example, gas-fired plants generally produce negligible quantities of particulate matter and sulfur oxides, and levels of nitrogen oxides are about 60% of those from plants using coal (without emission reduction measures). Natural gas-fired plants also release lower quantities of carbon dioxide, a greenhouse gas.

Some measures, such as choice of fuel and use of measures to increase energy conversion efficiency, will reduce emissions of multiple air pollutants, including CO2, per unit of energy generation. Optimizing energy utilization efficiency of the generation process depends on a variety of factors, including the nature and quality of fuel, the type of combustion system, the operating temperature of the combustion turbines, the operating pressure and temperature of steam turbines, the local climate conditions, the type of cooling system used, etc.
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<tr>
<th>Source</th>
<th>Cleaner Production Measures</th>
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<tbody>
<tr>
<td>Emissions to air from the combustion of fossil fuels or biomass</td>
<td>➢ Use of the cleanest fuel economically available (natural gas is preferable to oil, which is preferable to coal) if that is consistent with the overall energy and environmental policy of the country or the region where the plant is proposed. For most large power plants, fuel choice is often part of the national energy policy, and fuels, combustion technology and pollution control technology, which are all interrelated, should be evaluated very carefully upstream of the project to optimize the project’s environmental performance.</td>
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<td>➢ When burning coal, giving preference to high-heat-content, low-ash, and low-sulfur coal.</td>
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<td></td>
<td>➢ Considering beneficiation to reduce ash content, especially for high ash coal.</td>
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<td></td>
<td>➢ Selection of the best power generation technology for the fuel chosen to balance the environmental and economic benefits. The choice of technology and pollution control systems will be based on the site-specific environmental assessment (some examples include the use of higher energy-efficient systems, such as combined cycle gas turbine system for natural gas and oil-fired units, and supercritical, ultra supercritical or integrated coal gasification combined cycle (IGCC) technology for coal-fired units).</td>
</tr>
<tr>
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<td>➢ Designing stack heights according to Good International Industry Practice (GIIP) to avoid excessive ground level</td>
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Concentrations and minimize impacts, including acid deposition.

- Considering use of combined heat and power (CHP, or cogeneration) facilities. By making use of otherwise wasted heat, CHP facilities can achieve thermal efficiencies of 70 – 90 percent, compared with 32 – 45 percent for conventional thermal power plants.

- As stated in the General EHS Guidelines, emissions from a single project should not contribute more than 25% of the applicable ambient air quality standards to allow additional, future sustainable development in the same airshed.

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<th>Sulfur Dioxide</th>
<th>Use of fuels with a lower content of sulfur where economically feasible.</th>
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<td>large differences in the sulfur content of different fuels</td>
<td>Use of lime (CaO) or limestone (CaCO3) in coal-fired fluidized bed combustion boilers to have integrated desulfurization which can achieve a removal efficiency of up to 80-90% through use of Fluidized Bed Combustion.</td>
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<td>Depending on the plant size, fuel quality, and potential for significant emissions of SO2, use of flue gas desulfurization (FGD) for large boilers using coal or oil and for large reciprocating engines. The optimal type of FGD system (e.g., wet FGD using limestone with 85 to 98% removal efficiency, dry FGD using lime with 70 to 94% removal efficiency, seawater FGD with up to 90% removal efficiency)</td>
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| Nitrogen Oxides                                                                 | Use of low NOX burners with other combustion modifications, such as low excess air (LEA) firing, for boiler plants. Installation of additional NO X controls for boilers may be necessary to meet emissions limits; a selective catalytic reduction (SCR) system can be used for pulverized coal fired, oil-fired, and gas-fired boilers or a selective non-catalytic reduction (SNCR) system for a fluidized-bed boiler.  
|                                                                              | Use of dry low-NO X combustors for combustion turbines burning natural gas.  
|                                                                              | Use of water injection or SCR for combustion turbines and reciprocating engines burning liquid fuels.  
|                                                                              | Optimization of operational parameters for existing reciprocating engines burning natural gas to reduce NOx emissions.  
|                                                                              | Use of lean-burn concept or SCR for new gas engines. |
| Particulate Matter                                                           | The proven technologies for particulate removal in power plants are fabric filters and electrostatic precipitators (ESPs), the choice between a fabric filter and an ESP depends on the fuel properties, type of FGD system if used for SO2 control, and ambient air quality objectives. Particulate matter can also be released during transfer and storage of coal and |
heavy fuel oil, coal, and solid biomass. additives, such as lime.

- Installation of dust controls capable of over 99% removal efficiency, such as ESPs or Fabric Filters (baghouses), for coal-fired power plants. The advanced control for particulates is a wet ESP, which further increases the removal efficiency and also collects condensables (e.g., sulfuric acid mist) that are not effectively captured by an ESP or a fabric filter.

- Use of loading and unloading equipment that minimizes the height of fuel drop to the stockpile to reduce the generation of fugitive dust and installing of cyclone dust collectors.

- Use of water spray systems to reduce the formation of fugitive dust from solid fuel storage in arid environments.

- Use of enclosed conveyors with well designed, extraction and filtration equipment on conveyor transfer points to prevent the emission of dust.

- For solid fuels of which fine fugitive dust could contain vanadium, nickel and Polycyclic Aromatic Hydrocarbons (PAHs) (e.g., in coal and petroleum coke), use of full enclosure during transportation and covering stockpiles where necessary.

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vanadium, nickel and Polycyclic Aromatic Hydrocarbons (PAHs) (e.g., in coal and petroleum coke), use of full enclosure during transportation and covering stockpiles where necessary.

- Design and operate transport systems to minimize the generation and transport of dust on site.
- Storage of lime or limestone in silos with well designed, extraction and filtration equipment.
- Use of wind fences in open storage of coal or use of enclosed storage structures to minimize fugitive dust emissions where necessary, applying special ventilation systems in enclosed storage to avoid dust explosions (e.g., use of cyclone separators at coal transfer points).

**Other Pollutants**

Depending on the fuel type and quality, other air pollutants may be present in environmentally significant quantities requiring proper consideration in the evaluation of potential impacts to ambient air quality and in the design and implementation of management actions and environmental controls. Examples of additional pollutants include mercury in coal, vanadium in heavy fuel oil, and other heavy metals present in waste fuels such as petroleum coke (pet-coke) and used lubricating oils prevent, minimize, and control emissions of other air pollutants such as mercury in particular from thermal power plants include the use of conventional secondary controls such as fabric filters or ESPs operated in combination with FGD techniques, such as limestone FGD, Dry Lime FGD, or sorbent injection.
Additional removal of metals such as mercury can be achieved in a high dust SCR system along with powered activated carbon, bromine enhanced Powdered Activated Carbon (PAC) or other sorbents. Since mercury emissions from thermal power plants pose potentially significant local and transboundary impacts to ecosystems and public health and safety through bioaccumulation, particular consideration should be given to their minimization in the environmental assessment and accordingly in plant design.

**B. Energy Efficiency and GHG Emissions**

Carbon dioxide, one of the major greenhouse gases (GHGs) under the UN Framework Convention on Climate Change, is emitted from the combustion of fossil fuels.

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<td><strong>GHG Emissions</strong></td>
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<tr>
<td>Carbon dioxide</td>
<td>➢ Use of less carbon intensive fossil fuels (i.e., less carbon containing fuel per unit of calorific value -- gas is less than oil and oil is less than coal) or co-firing with carbon neutral fuels (i.e., biomass).</td>
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<tr>
<td>Fossil fuel</td>
<td>➢ Use of combined heat and power plants (CHP) where feasible.</td>
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<td>➢ Use of higher energy conversion efficiency technology of the same fuel type / power plant size than that of the country/region average. New facilities should be aimed to be in top quartile of the country/region average of the same fuel type and power plant size. Rehabilitation of existing facilities must achieve significant improvements in efficiency.</td>
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<td>➢ Consider efficiency-relevant trade-offs between capital and operating costs involved in the use of different technologies.</td>
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For example, supercritical plants may have a higher capital cost than subcritical plants for the same capacity, but lower operating costs. On the other hand, characteristics of existing and future size of the grid may impose limitations in plant size and hence technological choice.

- Use of high performance monitoring and process control techniques, good design and maintenance of the combustion system so that initially designed efficiency performance can be maintained.

- Where feasible, arrangement of emissions offsets (including the Kyoto Protocol’s flexible mechanisms and the voluntary carbon market), including reforestation, aorestation, or capture and storage of CO\textsuperscript{2} or other currently experimental options.

- Where feasible, include transmission and distribution loss reduction and demand side measures. For example, an investment in peak load management could reduce cycling requirements of the generation facility thereby improving its operating efficiency. The feasibility of these types of off-set options may vary depending on whether the facility is part of a vertically integrated utility or an independent power producer.

- Consider fuel cycle emissions and off-site factors (e.g., fuel supply, proximity to load centers, potential for off-site use of waste heat, or use of nearby waste gases (blast furnace gases...
Effluents

Effluents from thermal power plants include thermal discharges, wastewater effluents, and sanitary wastewater.

Thermal Discharges

Thermal power plants with steam-powered generators and once-through cooling systems use significant volume of water to cool and condense the steam for return to the boiler. The heated water is normally discharged back to the source water (i.e., river, lake, estuary, or the ocean) or the nearest surface water body. In general, thermal discharge should be designed to ensure that discharge water temperature does not result in exceeding relevant ambient water quality temperature standards outside a scientifically established mixing zone. The mixing zone is typically defined as the zone where initial dilution of a discharge takes place within which relevant water quality temperature standards are allowed to exceed and takes into account cumulative impact of seasonal variations, ambient water quality, receiving water use, potential receptors and assimilative capacity among other considerations. Establishment of such a mixing zone is project specific and may be established by local regulatory agencies and confirmed or updated through the project's environmental assessment process. Where no regulatory standard exists, the acceptable ambient water temperature change will be established through the environmental assessment process. Thermal discharges should be designed to prevent negative impacts to the receiving water taking into account the following criteria:

- The elevated temperature areas because of thermal discharge from the project should not impair the integrity of the water body as a whole or endanger sensitive areas (such as recreational areas, breeding grounds, or areas with sensitive biota);
There should be no lethality or significant impact to breeding and feeding habits of organisms passing through the elevated temperature areas;

There should be no significant risk to human health or the environment due to the elevated temperature or residual levels of water treatment chemicals.

If a once-through cooling system is used for large projects (i.e., a plant with > 1,200MWth steam generating capacity), impacts of thermal discharges should be evaluated in the EA with a mathematical or physical hydrodynamic plume model, which can be a relatively effective method for evaluating a thermal discharge to find the maximum discharge temperatures and flow rates that would meet the environmental objectives of the receiving water.

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| Effluent: Thermal Discharges | ➢ Use of multi-port diffusers.  
➢ Adjustment of the discharge temperature, flow, outfall location, and outfall design to minimize impacts to acceptable level (i.e., extend length of discharge channel before reaching the surface water body for pre-cooling or change location of discharge point to minimize the elevated temperature areas).  
➢ Use of a closed-cycle, recirculating cooling water system as described above (e.g. natural or forced draft cooling tower), or closed circuit dry cooling system (e.g., air cooled condensers) if necessary to prevent unacceptable adverse impacts. Cooling ponds or cooling towers are the primary technologies for a recirculating cooling water system. |
Liquid Waste

The wastewater streams in a thermal power plant include cooling tower blow down ash handling wastewater; wet FGD system discharges; material storage runoff; metal cleaning wastewater; and low-volume wastewater, such as air heater and precipitator wash water, boiler blowdown, boiler chemical cleaning waste, floor and yard drains and sumps, laboratory wastes, and back flush from ion exchange boiler water purification units. All of these wastewaters are usually present in plants burning coal or biomass; some of these streams (e.g., ash handling wastewater) may be present in reduced quantities or may not be present at all in oil-fired or gas-fired power plants. The characteristics of the wastewaters generated depend on the ways in which the water has been used. Contamination arises from demineralizers, lubricating and auxiliary fuel oils, trace contaminants in the fuel (introduced through the ash-handling wastewater and wet FGD system discharges) and chlorine, biocides, and other chemicals used to manage the quality of water in cooling systems. Cooling tower blow down tends to be very high in total dissolved solids but is generally classified as non-contact cooling water and, as such, is typically subject to limits for pH, residual chlorine, and toxic chemicals that may be present in cooling tower additives (including corrosion inhibiting chemicals containing chromium and zinc whose use should be eliminated).

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| **Effluent Liquid Discharges** | ➢ Recycling of wastewater in coal-fired plants for use as FGD makeup. This practice conserves water and reduces the number of wastewater streams requiring treatment and discharge  
➢ In coal-fired power plants without FGD systems, treatment of process wastewater in conventional physical-chemical treatment systems for pH adjustment and removal of total suspended solids (TSS), and oil / grease, at a minimum. Depending on local regulations, these treatment systems can also be used to remove most heavy metals to part-per-billion |
(ppb) levels by chemical precipitation as either metal hydroxide or metal organosulfide compounds.

- Collection of fly ash in dry form and bottom ash in drag chain conveyor systems in new coal-fired power plants.

- Consider use of soot blowers or other dry methods to remove fireside wastes from heat transfer surfaces so as to minimize the frequency and amount of water used in fireside washes.

- Use of infiltration and runoff control measures such as compacted soils, protective liners, and sedimentation controls for runoff from coal piles.

- Spraying of coal piles with anionic detergents to inhibit bacterial growth and minimize acidity of leachate.

- Use of SO\textsubscript{X} removal systems that generate less wastewater, if feasible; however, the environmental and cost characteristics of both inputs and wastes should be assessed on a case-by-case basis.

- Treatment of low-volume wastewater streams that are typically collected in the boiler and turbine room sumps in conventional oil-water separators before discharge.

- Treatment of acidic low-volume wastewater streams, such as
those associated with the regeneration of makeup
demineralizer and deep-bed condensate polishing systems, by
chemical neutralization in-situ before discharge.

- Pretreatment of cooling tower makeup water, installation of
  automated bleed/feed controllers, and use of inert
  construction materials to reduce chemical treatment
  requirements for cooling towers.

- Elimination of metals such as chromium and zinc from
  chemical additives used to control scaling and corrosion in
  cooling towers.

- Use the minimum required quantities of chlorinated biocides
  in place of brominated biocides or alternatively apply
  intermittent shock dosing of chlorine as opposed to
  continuous low level feed.

**Solid Wastes**

Coal-fired and biomass-fired thermal power plants generate the greatest amount of solid wastes
due to the relatively high percentage of ash in the fuel. The large volume coal combustion wastes
(CCW) are fly ash, bottom ash, boiler slag, and FGD sludge. Biomass contains less sulfur;
therefore FGD may not be necessary. Fluidized-bed combustion (FBC) boilers generate fly ash
and bottom ash, which is called bed ash. Fly ash removed from exhaust gases makes up 60–85% of
the coal ash residue in pulverized-coal boilers and 20% in stoker boilers.

Bottom ash includes slag and particles that are coarser and heavier than fly ash. Due to the
presence of sorbent material, FBC wastes have a higher content of calcium and sulfate and a
lower content of silica and alumina than conventional coal combustion wastes. Low-volume solid wastes from coal-fired thermal power plants and other plants include coal mill rejects/pyrites, cooling tower sludge, wastewater treatment sludge, and water treatment sludge.

Oil combustion wastes include fly ash and bottom ash and are normally only generated in significant quantities when residual fuel oil is burned in oil-fired steam electric boilers. Other technologies (e.g., combustion turbines and diesel engines) and fuels (e.g., distillate oil) generate little or no solid wastes. Overall, oil combustion wastes are generated in much smaller quantities than the large-volume CCW discussed above. Gas-fired thermal power plants generate essentially no solid waste because of the negligible ash content, regardless of the combustion technology.

Metals are constituents of concern in both CCW and low-volume solid wastes. For example, ash residues and the dust removed from exhaust gases may contain significant levels of heavy metals and some organic compounds, in addition to inert materials.

Ash residues are not typically classified as a hazardous waste due to their inert nature. However, where ash residues are expected to contain potentially significant levels of heavy metals, radioactivity, or other potentially hazardous materials, they should be tested at the start of plant operations to verify their classification as hazardous or non-hazardous according to local regulations or internationally recognized standards.

The high-volume CCWs wastes are typically managed in landfills or surface impoundments or, increasingly, may be applied to a variety of beneficial uses. Low-volume wastes are also managed in landfills or surface impoundments, but are more frequently managed in surface impoundments. Many coal-fired plants co-manage large volume and low volume wastes.

<table>
<thead>
<tr>
<th>Source</th>
<th>Cleaner Production Measures</th>
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<tbody>
<tr>
<td>Solid Waste</td>
<td>✓ Dry handling of the coal combustion wastes, in particular fly ash. Dry handling methods do not involve surface impoundments and, therefore, do not present the ecological</td>
</tr>
<tr>
<td>Fly ash, bottom ash, boiler</td>
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</tbody>
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slag, and FGD sludge.

- Recycling of CCWs in uses such as cement and other concrete products, construction fills (including structural fill, flow able fill, and road base), agricultural uses such as calcium fertilizers (provided trace metals or other potentially hazardous materials levels are within accepted thresholds), waste management applications, mining applications, construction materials (e.g., synthetic gypsum for plasterboard), and incorporation into other products provided the residues (such as trace metals and radioactivity) are not considered hazardous. Ensuring consistent quality of fuels and additives helps to ensure the CCWs can be recycled. If beneficial reuse is not feasible, disposal of CCW in permitted landfills with environmental controls such as run-on/run-off controls, liners, leachate collection systems, ground-water monitoring, closure controls, daily (or other operational) cover, and fugitive dust controls is recommended.

- Dry collection of bottom ash and fly ash from power plants combusting heavy fuel oil if containing high levels of economically valuable metals such as vanadium and recycle for vanadium recovery (where economically viable) or disposal in a permitted landfill with environmental controls.

- Management of ash disposal and reclamation so as to minimize environmental impacts – especially the migration of toxic metals, if present, to nearby surface and groundwater bodies, in addition to the transport of suspended solids in
surface runoff due to seasonal precipitation and flooding. In particular, construction, operation, and maintenance of surface impoundments should be conducted in accordance with internationally recognized standards.

- Reuse of sludge from treatment of waste waters from FGD plants. This sludge may be re-used in the FGD plant due to the calcium components. It can also be used as an additive in coal-fired plant combustion to improve the ash melting behavior.

**Hazardous Materials and Oil**

Hazardous materials stored and used at combustion facilities include solid, liquid, and gaseous waste-based fuels; air, water, and wastewater treatment chemicals; and equipment and facility maintenance chemicals (e.g., paint certain types of lubricants, and cleaners).

Additional measures to prevent, minimize, and control hazards associated with hazardous materials storage and handling at thermal power plants include the use of double-walled, underground pressurized tanks for storage of pure liquefied ammonia (e.g., for use as reagent for SCR) in quantities over 100 m³; tanks of lesser capacity should be manufactured using annealing processes (EC 2006).

**Noise**

Principal sources of noise in thermal power plants include the turbine generators and auxiliaries; boilers and auxiliaries, such as coal pulverizers; reciprocating engines; fans and ductwork; pumps; compressors; condensers; precipitators, including rappers and plate vibrators; piping and valves; motors; transformers; circuit breakers; and cooling towers. Thermal power plants used
for base load operation may operate continually while smaller plants may operate less frequently but still pose a significant source of noise if located in urban areas.

<table>
<thead>
<tr>
<th>Source</th>
<th>Cleaner Production Measures</th>
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| Noise  | ➢ Siting new facilities with consideration of distances from the noise sources to the receptors (e.g., residential receptors, schools, hospitals, religious places) to the extent possible. If the local land use is not controlled through zoning or is not effectively enforced, examine whether residential receptors could come outside the acquired plant boundary. In some cases, it could be more cost effective to acquire additional land as buffer zone than relying on technical noise control measures, where possible.  
➢ Use of noise control techniques such as: using acoustic machine enclosures; selecting structures according to their noise isolation effect to envelop the building; using mufflers or silencers in intake and exhaust channels; using sound absorptive materials in walls and ceilings; using vibration isolators and flexible connections (e.g., helical steel springs and rubber elements); applying a carefully detailed design to prevent possible noise leakage through openings or to minimize pressure variations in piping.  
➢ Modification of the plant configuration or use of noise barriers such as berms and vegetation to limit ambient noise at plant property lines, especially where sensitive noise receptors may be present. |

Turbine generators and auxiliaries, boilers and auxiliaries, such as coal pulverizers, reciprocating engines, fans and ductwork, pumps. Compressors, condensers, precipitators, including rappers and plate vibrators; piping and valves, motors, transformers, circuit breakers, and cooling towers.
Noise propagation models may be effective tools to help evaluate noise management options such as alternative plant locations, general arrangement of the plant and auxiliary equipment, building enclosure design, and, together with the results of a baseline noise assessment, expected compliance with the applicable community noise requirements.

Reference:
(http://www.ifc.org/wps/wcm/connect/Topics_Ext_Content/IFC_External_Corporate_Site/IFC+Sustainability/Sustainability+Framework/Environmental,+Health,+and+Safety+Guidelines/)