Environmental, Health, and Safety Guidelines for Thermal Power Plants

Introduction

1. The Environmental, Health, and Safety (EHS) Guidelines are technical reference documents with general and industry-specific examples of Good International Industry Practice (GIIP). When one or more members of the World Bank Group are involved in a project, these EHS Guidelines are applied as required by their respective policies and standards. These industry sector EHS guidelines are designed to be used together with the General EHS Guidelines document, which provides guidance to users on common EHS issues potentially applicable to all industry sectors. For complex projects, use of multiple industry-sector guidelines may be necessary. A complete list of industry-sector guidelines can be found at: www.ifc.org/ehsguidelines.

2. The EHS Guidelines contain the performance levels and measures that are generally considered to be achievable in new facilities by existing technology at reasonable costs. Application of the EHS Guidelines to existing facilities may involve the establishment of site-specific targets, based on environmental assessments and/or environmental audits as appropriate, with an appropriate timetable for achieving them.

3. The applicability of the EHS Guidelines should be tailored to the hazards and risks established for each project on the basis of the results of an environmental assessment (EA) in which site-specific variables, such as host country context, assimilative capacity of the environment, and other project factors, are taken into account. The applicability of specific technical recommendations should be based on the professional opinion of qualified and experienced persons.

4. When host country regulations differ from the levels and measures presented in the EHS Guidelines, projects are expected to achieve whichever is more stringent. If less stringent levels or measures than those provided in these EHS Guidelines are appropriate, in view of specific project circumstances, a full and detailed justification for any proposed alternatives is needed as part of the site-specific environmental assessment. This justification should demonstrate that the choice for any alternate performance levels is protective of human health and the environment.

1 Defined as the exercise of professional skill, diligence, prudence and foresight that would be reasonably expected from skilled and experienced professionals engaged in the same type of undertaking under the same or similar circumstances globally. The circumstances that skilled and experienced professionals may find when evaluating the range of pollution prevention and control techniques available to a project may include, but are not limited to, varying levels of environmental degradation and environmental assimilative capacity as well as varying levels of financial and technical feasibility.
Applicability

5. This document includes information relevant to combustion, gasification or pyrolysis processes fueled by gaseous, liquid and solid fossil fuels and biomass and designed to deliver electrical or mechanical power, steam, heat, or any combination of these, regardless of the fuel type (except for solid waste which is covered under a separate Guideline for Waste Management Facilities), with a total rated heat input capacity equal to or above 50 Megawatt thermal input (MWth) on Higher Heating Value (HHV) basis. It applies to boilers, reciprocating engines, and combustion turbines in new and existing facilities. The guidelines do not apply to fuel cells. Annex A contains a detailed description of industry activities for this sector, and Annex B contains guidance for Environmental Assessment (EA) of thermal power projects. Emissions guidelines applicable to facilities with a total heat input capacity of less than 50 MWth are presented in Section 1.1 of the General EHS Guidelines. Depending on the characteristics of the project and its associated activities (i.e., fuel sourcing and evacuation of generated electricity), readers should also consult the EHS Guidelines for Mining and the EHS Guidelines for Electric Power Transmission and Distribution.

6. Decisions to invest in this sector by one or more members of the World Bank Group are made within the context of the World Bank Group strategy on climate change.

7. This document is organized according to the following sections:

Section 1.0 – Industry Specific Impacts and Management
Section 2.0 – Performance Indicators and Monitoring
Section 3.0 – References and Additional Sources
Annex A – General Description of Industry Activities
Annex B – Environmental Assessment Guidance for Thermal Power Projects

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2 The guidelines only apply to gasification processes where syngas is produced and combusted to deliver power, steam and/or heat at the same facility. The production of syngas for other purposes or for export off site is not covered by these guidelines.

3 Throughout this document, biomass refers to living or recently dead biological material that can be used as fuel or for industrial production. Biomass can be obtained from several sources, including but not limited to wood, straw, miscanthus (elephant grass), hemp, corn (maize), sugarcane (bagasse), rice, palm (palm oil, coconut) among others. Biomass refers also to the biofuels (solid, liquid, gaseous) that can be produced from biomass.

4 Total capacity applicable to a facility with multiple units.

1.0 Industry-Specific Impacts and Management

8. The following section provides a summary of the most significant EHS issues associated with thermal power plants, which occur during the operational phase, along with recommendations for their management.

9. As described in the introduction to the General EHS Guidelines, the general approach to the management of EHS issues in industrial development activities, including power plants, should consider potential impacts as early as possible in the project cycle, including the incorporation of EHS considerations into the site selection and plant design processes in order to maximize the range of options available to prevent and control potential negative impacts.

10. Recommendations for the management of EHS issues common to most large industrial and infrastructure facilities during the construction and decommissioning phases are provided in the General EHS Guidelines.

1.1 Environment

11. Environmental issues in thermal power plant projects primarily include the following:

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

Air Emissions

12. The primary emissions to air from the combustion of fossil fuels or biomass are sulfur dioxide (SO$_2$), nitrogen oxides (NO$_x$), particulate matter (PM), carbon monoxide (CO), and greenhouse gases, such as carbon dioxide (CO$_2$). 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 chloride and hydrogen fluoride), dioxins and furans, 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.

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$^{6}$ PM is defined as total suspended particulates. PM includes PM10 (particles with diameters that are 10 micrometres and smaller) and PM2.5 (particles with diameters that are 2.5 micrometres and smaller). Impacts from fugitive sources (such as from coal / coal ash storage areas) may also occur due to subsequent deposition to surfaces.
and/or persistence. Sulfur dioxide and nitrogen oxides are also implicated in long-range and trans-boundary acid deposition.

13. The amount and nature of air emissions depend 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, natural gas-fired plants generally produce negligible quantities of particulate matter and sulfur oxides, and levels of nitrogen oxides are about 60% lower than those from coal plants using coal (without emission reduction measures), mainly due to differences in the fuel composition (ash, sulfur and nitrogen contents, respectively). Natural gas-fired plants also release lower quantities of carbon dioxide, a greenhouse gas, per unit of energy generated than do liquid and solid fossil fuel-fired plants.

14. 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, generation cycle type chosen (e.g., reciprocating engine, single or combined cycle gas turbine, steam turbine), its configuration (e.g., electricity generation or co- or tri-generation of electricity, heating and cooling), 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., and potential for nearby heat users. Recommended measures to prevent, minimize, and control air emissions include:

- Use of the cleanest fuel economically available (for example, 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;
- When burning coal, giving preference to high-heat-content, low-ash, and low-sulfur coal;
- Considering beneficiation to reduce ash content, especially for high ash coal by coal washing;
- Selection of the best power generation technology and pollution control technologies 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 (EA). 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 potentially in the future integrated coal gasification.

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7 Coal washing is widespread in developed countries and increasingly is being introduced in developing countries. In India, around 20 percent of thermal coal was washed in 2014 compared to a global average of 50 percent (Infraline Energy, 2010). In China, approximately 40 percent of thermal coal is washed (Wang, 2013). If sulfur is inorganically bound to the ash, this beneficiation will also reduce sulfur content.
combined cycle (IGCC) technology or carbon capture and storage (CCS) for coal-fired units);  

- Designing stack heights and configurations according to Good International Industry Practice (GIIP) to avoid excessive ground level concentrations and minimize impacts, including acid deposition;  

- Considering use of combined heat and power (CHP, or co-generation) facilities. By making use of otherwise wasted combining useful heat output with power production, CHP facilities can achieve thermal efficiencies of 70—90 percent, compared with 32—45 the 30–60 percent for conventional electrical efficiencies available from thermal power-only plants, which can contribute to primary energy savings.  

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

  The approach described in Section 1.1 of the General EHS Guidelines should be followed.

Baseline Air Quality Data

15. Establishing baseline air quality is an important step in determining (i) whether the airshed is degraded or not, which in turn dictates the emission guideline values applicable to a project and (ii) whether emissions offsets are required. Data should be collected on ambient concentrations of relevant parameters including, for example, PM_{10}, PM_{2.5}, SO_2 (when sulfur containing fuels are used), NO_x, and ground-level ozone. Data should be collected within a defined airshed encompassing the proposed project, over averaging times consistent with relevant ambient air quality standards (such as 1-hour maximum, 24-hour maximum, annual average).

16. The scope of baseline data collection will depend on the project circumstances (e.g., project size, other emission sources in the airshed and the potential impacts on the airshed). Examples of suggested practices are:

- Seasonal manual sampling (for small or mid-sized projects e.g., < 1,200MWth).

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8 According to Global CCS Institute, there are currently 15 large-scale CCS projects in operation worldwide located in the North Sea (Sneihvit and Sleipner), Algeria (In Salah), USA (Great Plains and Shute Creek), Canada (Boundary Dam and Quest), Brazil (Lula) and Saudi Arabia (Uthmaniyah). All new consented power plants of over 300MWe in Europe are CCR (requirement under EU Directive 2009/31/EC on the geological storage of carbon dioxide).

9 For specific guidance on calculating stack height, see Annex 1.1.3 of the General EHS Guidelines. Raising stack height should not be used to allow more emissions. However, if the proposed emission rates result in significant incremental ambient air quality impacts to the attainment of the relevant ambient air quality standards, options to raise stack height and/or to further reduce emissions should be considered in the EA. Typical examples of GIIP stack heights are up to around 200m for large coal-fired power plants, up to around 80m for HFO-fired power plants, up to around 50m for gas-fired power plants, and up to 100m for gas-fired combined cycle gas turbine power plants. Final selection of the stack height will depend on the terrain of the surrounding areas, nearby buildings, meteorological conditions, predicted incremental impacts and the location of existing and future receptors. Bundling of multiple flues into a common stack should be undertaken where practicable and where this is beneficial for air quality. Note that, in most cases, bundling of multiple flues into a common stack is beneficial.

10 For example, the US EPA Prevention of Significant Deterioration Increments Limits applicable to non-degraded airsheds provide the following: SO_2 (91 μg/m^3 for 24-hour), 20 μg/m^3 for annual average), NO_x (20 μg/m^3 for annual average), PM_{10} (30 μg/m^3 for 24-hour, and 17 μg/m^3 for annual average). The term “airshed” refers to the local area around the plant whose ambient air quality is directly affected by emissions from the plant. The size of the relevant local airshed will depend on plant characteristics, such as stack height, as well as on local meteorological conditions and topography. In some cases, airsheds are defined in legislation or by the relevant environmental authorities. If not, the EA should clearly define the airshed on the basis of consultations with those responsible for local environmental management.

17. Baseline meteorological data collection is also likely to be required to support dispersion modelling in the air quality assessment. This data can be sourced from an existing meteorological station in the area, a site-specific meteorological station installed for the project, or prognostic meteorological data. In all cases, the data should be representative of the airshed and of a quality and format suitable for the modelling approach used. This includes taking account of likely fluctuations in meteorological conditions. As a general guideline, between three and five years of meteorological data can be considered to represent the range of conditions relevant to ambient air quality prediction.

Air emission controls

15.18. Pollutant-specific control recommendations are provided below, though it should be noted that some emissions abatement offer multi-pollutant control benefits.

Sulfur Dioxide

16.19. The range of options for the control of sulfur oxides varies substantially because of large differences in the sulfur content of different fuels and in control costs as described in Table 1. The choice of technology depends on a cost-benefit analysis of the environmental performance of different fuels, the cost of controls, and the existence of a market for sulfur control by-products.13 Recommendmeasures to prevent, minimize, and control SO₂ emissions include:

- Use of fuels with a lower sulfur content of sulfur where economically feasible;
- Use of lime (CaO) or limestone (CaCO₃) for integrated desulfurization 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 Combustion14,15—approximately 95 percent16,17;
- Depending on the plant size, fuel quality, and potential for significant SO₂ 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% percent removal efficiency, semi-dry FGD using lime with 70% to 94% percent removal efficiency, seawater FGD with up to 90% percent removal efficiency) depends on the capacity of the plant, fuel properties, site conditions, residual life of the facility.

13 Regenerative Flue Gas Desulfurization (FGD) options (either wet or semi-dry) may be considered under these conditions.
15 EC (2016). FBC boilers can achieve SOx removal efficiencies of 80–90% in bubbling FBC boilers and more than 90–95 % in circulating FBC boilers.
16 The SO₂ removal efficiency of FBC technologies depends on the sulfur and lime content of fuel, sorbent quantity, ratio, and quality.
17 The SO₂ removal efficiency of FBC technologies depends on the sulfur and lime content of fuel, sorbent quantity, ratio, and quality.
and the cost and availability of reagent as well as by-product disposal and utilization.\(^{18}\)

- **OIL-fired reciprocating engine plants are generally too small in capacity to justify wet scrubbing, due to costs. If reducing fuel sulfur is insufficient, these plants would generally use semi-dry scrubbing using either slaked/hydrated lime (Ca(OH)\(_2\)) or sodium bicarbonate (NaHCO\(_3\)).**

<table>
<thead>
<tr>
<th>Table 1 - Performance / Characteristics of FGDs</th>
<th>Plant Capital Cost Increase(^A)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Type of FGD</strong></td>
<td><strong>Characteristics</strong></td>
</tr>
<tr>
<td>Wet FGD</td>
<td>• Flue gas is saturated with water</td>
</tr>
<tr>
<td></td>
<td>• Limestone (CaCO(_3)) as reagent</td>
</tr>
<tr>
<td></td>
<td>• Removal efficiency up to 98% but dependent on limestone reactivity, inlet SO(_2) concentration, and FGD design capacity</td>
</tr>
<tr>
<td></td>
<td>• Use: 1(\text{--}1.5)% of electricity generated</td>
</tr>
<tr>
<td></td>
<td>• Most widely used</td>
</tr>
<tr>
<td></td>
<td>• Distance to limestone source and the limestone reactivity to be considered</td>
</tr>
<tr>
<td></td>
<td>• High water consumption</td>
</tr>
<tr>
<td></td>
<td>• Need to treat wastewater</td>
</tr>
<tr>
<td></td>
<td>• Gypsum as a saleable by-product or waste</td>
</tr>
<tr>
<td>Semi-Dry FGD</td>
<td>• Also called “Dry Scrubbing” under controlled humidification.</td>
</tr>
<tr>
<td></td>
<td>• Lime (CaO) or sodium bicarbonate (NaHCO(_3)) as reagent</td>
</tr>
<tr>
<td></td>
<td>• Removal efficiency up to 94% but dependent on inlet SO(_2) concentration and sorbent reactivity</td>
</tr>
<tr>
<td></td>
<td>• Can remove SO(_3) as well at higher removal rate than Wet FGD</td>
</tr>
<tr>
<td></td>
<td>• Use: 0.5% Uses up to 1.0% of electricity generated, less than Wet FGD</td>
</tr>
<tr>
<td></td>
<td>• Lime or sodium bicarbonate is more expensive than limestone</td>
</tr>
<tr>
<td></td>
<td>• No wastewater</td>
</tr>
<tr>
<td></td>
<td>• Waste — Solid waste — mixture of fly ash, unreacted additive (high pH) and CaSO(_4) inert reaction products</td>
</tr>
<tr>
<td>Seawater FGD</td>
<td>• Removal efficiency up to 90%</td>
</tr>
<tr>
<td></td>
<td>• Not practical for high S coal ((&gt;1)%S)</td>
</tr>
<tr>
<td></td>
<td>• Impacts on marine environment need to be carefully examined (e.g., reduction of pH, inputs of remaining heavy metals, fly ash, temperature, sulfate, dissolved oxygen, and chemical oxygen demand)</td>
</tr>
<tr>
<td></td>
<td>• Use: Install downstream of PM removal, to avoid contamination of return sea water</td>
</tr>
<tr>
<td></td>
<td>• Use: 0.8% - 1.6% of electricity generated</td>
</tr>
<tr>
<td></td>
<td>• Simple process, no separate wastewater or solid waste</td>
</tr>
</tbody>
</table>

**Sources:** EC (2005, 2016)

\(^A\) Dry FGD typically has lower capital costs than wet FGD, but higher operating costs due to the costs associated with reagent. Seawater FGD tends to have relatively low operating costs compared to wet / semi-dry FGD. Costs for FGD equipment depend on the flue gas characteristics rather than the source of the emissions. Therefore, FGD percentage cost increases for oil-fired reciprocating engine plants will generally be much higher than for oil-fired steam power plants, as reciprocating engines tend to have lower costs per kWe than steam plants and World Bank Group power sulfur concentrations in the raw gases (higher excess air proportion).

\(^B\) Some typical costs for wet FGD are provided in the EU Large Combustion Plant (LCP) Final Draft BREF note (2016): “The capital costs for a wet limestone scrubbing process fitted to a boiler varies from EUR 35–50 per kWe for a new plant to EUR 60–300 per kWe in the case of retrofits. Operation and maintenance costs are between EUR 0.4 and EUR 0.7 per MWh (energy input). The typical SO\(_2\) removal costs are between EUR 750 and EUR 1150 per metric ton of SO\(_2\) removed, which corresponds to an impact of EUR 3–6 per MWh on the cost of electricity production.” (EC, 2016).

\(^C\) The EU LCP Final Draft BREF note (2016) estimates spray dry scrubber costs for a boiler case to be “EUR 7–45 per kWh (fuel energy input) in investment costs, and EUR 0.5–0.7 per MWh (heat input) operating and maintenance costs. The cost of the reduced pollutant was EUR 600–800 per metric ton of sulfur dioxide removed. The effect on the price of electricity was approximately EUR 6 per MWh (electricity produced)” (EC, 2016).

**Nitrogen Oxides**

\(^{18}\) The use of wet scrubbers, in addition to dust/particulate control equipment (e.g., ESP or fabric filters), has the advantage of also reducing emissions of HCl, HF, heavy metals, and further dust/particulates remaining after ESP or fabric filter. Wet scrubbing is almost always the system of choice for large utility coal- or oil-fired boilers. Because of higher costs, the wet scrubbing process is generally not used at boiler plants with a capacity of less than 100 MWe (100 MWe) (EC 2006—2016).
Formation of nitrogen oxides can be controlled by modifying operational and design parameters of the combustion process (primary measures), such as:

- Use of low NOₓ burners with other combustion modifications, such as low excess air (LEA) firing, over-fire air, or flue gas recirculation for boiler plants;
- Use of dry low-NOₓ combustors for combustion turbines burning natural gas;
- Use of water injection for combustion turbines using liquid fuels;¹⁹
- Optimization of operational parameters for existing reciprocating engines burning natural gas to reduce NOₓ emissions;
- Use of lean-burn, cool operating concept for new gas engines; and
- Use of Miller principle for reciprocating engines.²⁰

Additional treatment of NOₓ from the flue gas (secondary measures; see Table 2) may be required in some cases depending on the need to meet emissions limits and/or ambient air quality objectives. Recommended secondary measures to prevent, minimize, and control NOₓ emissions include:

**Table 2 - Performance / Characteristics of Secondary NOₓ Reduction Systems**

<table>
<thead>
<tr>
<th>Type</th>
<th>Characteristics</th>
<th>Plant Capital Cost Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR</td>
<td>NOₓ emission reduction rate of 80–95%</td>
<td>4–9% (coal-fired boilers)</td>
</tr>
<tr>
<td></td>
<td>Use 0.5% of electricity generated</td>
<td>1–2% (gas-fired combined cycle gas turbine)</td>
</tr>
<tr>
<td></td>
<td>Use ammonia or urea as reagent</td>
<td>20–30% (reciprocating engines)</td>
</tr>
<tr>
<td></td>
<td>Ammonia slip increases with increasing NH₃/NOₓ ratio may cause a problem (e.g., too high ammonia in the fly ash). Larger catalyst volume / improving the mixing of NH₃ and NOₓ in the flue gas may be needed to avoid this problem.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Catalysts may contain heavy metals. Proper handling and disposal / recycle of spent catalysts is needed.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Life of catalysts has been 6–10 years (coal-fired), 8–12 years (oil-fired) and more than 10 years (gas-fired).</td>
<td></td>
</tr>
<tr>
<td>SNCR</td>
<td>NOₓ emission reduction rate of 30–50%</td>
<td>1%</td>
</tr>
<tr>
<td></td>
<td>Use 0.1–0.3% of electricity generated</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Use ammonia or urea as reagent</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cannot be used on gas turbines or gas engines.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Operates without using catalyst</td>
<td></td>
</tr>
</tbody>
</table>

Source: EC (2006), World Bank Group

- Use of low NOₓ burners with other combustion modifications, such as low excess air (LEA) firing, for boiler plants. Installation of additional NOₓ controls for boilers may be necessary to meet emissions limits. Use of 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; (or less effectively in other types of combustion boilers) and
- Use of dry low-NOₓ combustors for combustion turbines burning natural gas;

¹⁹ Water injection may not be practical for industrial combustion turbines in all cases depending on the availability of a suitable water supply.

²⁰ The Miller principle involves late or early closing of the air inlet valves to effectively make the compression stroke shorter than the expansion stroke. This increases the efficiency of the engine, and also suppresses in-cylinder temperatures and thus reduces NOₓ formation (UNECE, 2012).
- **Use of water injection or** SCR **for combustion turbines and reciprocating engines burning** gaseous or liquid fuels.  

**Table 2 - Performance / Characteristics of Secondary NO\(_x\) Reduction Systems**

<table>
<thead>
<tr>
<th>Type</th>
<th>Characteristics</th>
<th>Plant Capital Cost Increase(^a)</th>
</tr>
</thead>
</table>
| **SCR** | - NO\(_x\) emission reduction rate of 80–95%  
- Uses 0.5% of electricity generated  
- Uses ammonia or urea as reagent.  
- Ammonia slip increases with increasing NH\(_3\)/NO\(_x\) ratio may cause a problem (e.g., too high ammonia in the fly ash). Larger catalyst volume and improving the mixing of NH\(_3\) and NO\(_x\) in the flue gas may be needed to avoid this problem.  
- Requires optimal temperature window (generally above 370°C) for conventional catalysts.  
- Temperature minimum is dependent on SO\(_3\) content of flue gases, to avoid clogging of the matrix  
- For flue gases with high particulate loadings post-cleaning SCR, with lower temperature catalysts (e.g., 150–200°C) is feasible, but with lower effectiveness and extra complications of flue gas reheating  
- Catalysts may contain heavy metals. Proper handling and disposal / recycle of spent catalysts is needed.  
- Life of catalysts depends on the contaminant levels in the flue gases. For boiler plant lives of 6–10 years (coal-fired), 8–12 years (oil-fired) and more than 10 years (gas-fired) have been achieved. | 4–9% (coal-fired boiler)  
1–15% (gas-fired combined cycle combustion turbine)  
4–30% (reciprocating engines). |
| **SNCR** | - NO\(_x\) emission reduction rate of 50–70% (fluidized beds); 30–50% (other types of combustion boiler)  
- Uses 0.1–0.3% of electricity generated  
- Uses ammonia or urea as reagent.  
- Cannot be used effectively on gas turbines or gas engines, as these do not generally provide the right temperature and residence time conditions for the reaction between NO\(_x\) and the reagent.  
- Operates without using catalysts.  
- Potential for higher ammonia slip than SCR. | 1–2% |


\(^a\) Generally, the smaller the unit (i.e., the engine, boiler, CCGT) capacity, the higher the percentage capital cost increase. Higher SCR efficiency (for example where greater NO\(_x\) reduction is required to meet acceptable emission limits) also typically results in higher capital cost increases.

\(^b\) Electricity price increase associated with the use of SCR has been estimated at 7–11% for mainland Europe and 11–25% for remote areas such as islands (UNECE, 2011). Higher costs in remote areas are associated with the higher costs of transporting reagents to the plant.

\(^c\) SNCR typically has lower capital costs than SCR, but higher operational costs associated with the large quantities of reagent required (Process Combustion Corporation, 2016).

- Optimization of operational parameters for existing reciprocating engines burning natural gas to reduce NO\(_x\) emissions;
- Use of lean-burn concept or SCR for new gas engines.

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\(^{21}\) Water injection may not be practical for industrial combustion turbines in all cases. Even if water is available, the facilities for water treatment and the operating and maintenance costs of water injection may be costly and may complicate the operation of a small combustion turbine.
Particulate Matter (PM)

18.22. Particulate matter PM is emitted from the combustion process, especially from the use of heavy fuel oil, coal, and solid biomass. PM arises from incomplete combustion or the presence of incombustible material in the fuel. Primary PM abatement is to use natural gas, other gases or low ash liquid fuels instead of higher ash alternatives. The proven technologies for particulate removal in power plants are fabric filters (FFs) and electrostatic precipitators (ESPs), shown with characteristics summarized in Table 3. 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 Hybrid ESP/Fabric Filter equipment also exists. PM can also be released during transfer and storage of coal, biomass and additives, such as lime. Recommendations to prevent, minimize, and control particulate matter emissions include:

<table>
<thead>
<tr>
<th>Type</th>
<th>Performance / Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td>ESP</td>
<td>• Removal efficiency of &gt;96.5% (&lt;1 μm), &gt;99.95% (&gt;10 μm)</td>
</tr>
<tr>
<td></td>
<td>• Very dependent on particulate composition and size. For example, for new or rebuilt oil boilers only 90% capture may be achieved; and 40 to 60% on older boilers.</td>
</tr>
<tr>
<td></td>
<td>• 0.1–1.8% of electricity generated is used.</td>
</tr>
<tr>
<td></td>
<td>• It might not work on particulates with very high electrical resistivity. In these cases, flue gas conditioning (FGC) may improve ESP performance.</td>
</tr>
<tr>
<td></td>
<td>• Can handle very large gas volume with low pressure drops</td>
</tr>
<tr>
<td>Fabric Filter</td>
<td>• Removal efficiency of &gt;99.6% (&lt;1 μm), &gt;99.95% (&gt;10 μm). Removes smaller particles than ESPs.</td>
</tr>
<tr>
<td></td>
<td>• Performance degrades with time.</td>
</tr>
<tr>
<td></td>
<td>• Periodic replacement of filter bags needed, typically on a rolling three-year program, resulting in higher operating costs than ESPs</td>
</tr>
<tr>
<td></td>
<td>• 0.2–3% of electricity generated is used.</td>
</tr>
<tr>
<td></td>
<td>• Filter life decreases as coal S content increases</td>
</tr>
<tr>
<td></td>
<td>• Filter life affected by material choice and flue gas temperature. Suitable materials can typically operate at up to 220°C.</td>
</tr>
<tr>
<td></td>
<td>• Operating costs go up considerably as the fabric filter becomes dense to remove more particles</td>
</tr>
<tr>
<td></td>
<td>• If ash is particularly reactive, it can weaken the fabric and, which eventually disintegrates.</td>
</tr>
<tr>
<td></td>
<td>• Some fuels (such as oils) can clog the bag material, and so may not be suitable</td>
</tr>
<tr>
<td></td>
<td>• For solid fuels, by-pass of the filter during start-up on oil would be normal so as to avoid bag material contamination.</td>
</tr>
<tr>
<td>Wet Scrubber</td>
<td>• Removal efficiency of &gt;98.5% (&lt;1 μm), &gt;99.9% (&gt;10 μm)</td>
</tr>
<tr>
<td></td>
<td>• Up to 3% of electricity generated is used.</td>
</tr>
<tr>
<td></td>
<td>• As a secondary effect, can remove and absorb gaseous heavy metals</td>
</tr>
<tr>
<td></td>
<td>• Wastewater needs to be treated</td>
</tr>
<tr>
<td></td>
<td>• Exit flue gas is cold, and so may require reheating for dispersion purposes (increasing operating costs)</td>
</tr>
<tr>
<td></td>
<td>• Low capital costs compared to ESP and FF, which may be offset by relatively high operating costs</td>
</tr>
</tbody>
</table>


23. Recommendations to prevent, minimize, and control PM emissions include:

- Installation of dust particulate controls capable of over 99% percent removal efficiency, such as ESPs or Fabric Filters (baghouses), for coal/solid fuel-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;\footnote{Flue gas conditioning (FGC) is a recommended approach to address the issue of low gas conductivity and lower ESP collection performance which occurs when ESPs are used to collect dust particulates from very low sulfur fuels. One particular FGC design involves introduction of sulfur trioxide (SO$_3$) gas into the flue gas upstream of the ESP, to increase the conductivity of the flue gas dramatically improve the ESP collection efficiency. There is typically no risk of increased SOx emissions as the SO$_3$ is highly reactive and adheres to the dust particulates.}

- Use of ESP for HFO-fueled reciprocating engine power plants, including those using high ash and sulfur content fuel;
- Use of loading and unloading equipment that minimizes the height of solid fuel drop to the stockpile to reduce the generation of fugitive dustPM and installing of cyclone dustPM collectors;
- Use of water spray systems to reduce the formation of fugitive dustPM 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 dustPM;
- For solid fuels of which whose fine fugitive dustPM 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;
- Design and operate transport systems to minimize the generation and transport of dustPM on site;
- Storage of lime or limestone in silos with well designed, extraction and filtration equipment; and
- Use of wind fences in open storage of coal or other solid fuel (such as biomass), or use of enclosed storage structures to minimize fugitive dustPM emissions where necessary, applying special ventilation systems in enclosed storage to avoid dustPM explosions (e.g., use of cyclone separators at coal transfer points).

\footnote{In these cases, the EA should address potential impacts to ambient air quality for such heavy metals as mercury, nickel, vanadium, cadmium, lead, etc. The potential for significant impacts of heavy metal emissions is project specific and should be determined on a case-by-case basis. The approach adopted in the EU is to identify significant impacts; prescriptive methods for doing so are not defined. Where professional judgement or qualitative assessments are considered insufficient to screen out heavy metal impacts, the use of screening models (e.g., AERSCREEN or equivalent) may be appropriate to determine whether there is potential for significant impacts.}

See Annex 1.1.2 of the General EHS Guidelines for an additional illustrative presentation of point source emissions prevention and control technologies.

Other Pollutants

\footnote{In these cases, the EA should address potential impacts to ambient air quality for such heavy metals as mercury, nickel, vanadium, cadmium, lead, etc.} 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 (petcoke) and used lubricating oils. Recommendations to 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 powdered 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 (EA) and accordingly in plant design.

**Emissions Offsets**

21-26. Facilities in degraded airsheds should minimize incremental impacts by achieving emissions guideline values outlined in Table 6. Where these emissions values result nonetheless, and following the approach described in excessive Section 1.1 of the General EHS Guidelines, the project should explore and implement site-specific offsets that result in no net increase in the total emissions of those pollutants (e.g., particulate matter, sulfur dioxide, or nitrogen dioxide) that are responsible for the degradation of the airshed. Offset provisions should be implemented before the power plant comes fully on stream. Suitable offset measures could include reductions in emissions of particulate matter, sulfur dioxide, or nitrogen oxides, as necessary through (a) the installation of new or more effective controls at other units within the same power plant facility or at other power plants in the same airshed, (b) the installation of new or more effective controls at other large sources, such as district heating plants or industrial plants, in the same airshed, or (c) investments in gas distribution or district heating systems designed to substitute for the use of coal for residential heating and other small boilers. Wherever possible, the offset provisions should be implemented within the framework of an overall air quality management strategy designed to ensure that air quality in the airshed is brought into compliance with ambient standards. The monitoring and enforcement of ambient air quality in the airshed to ensure that offset provisions are complied with would be the responsibility of the local or national agency responsible for granting and supervising environmental permits.

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25 The EU Final Draft BAT Reference (BREF) note (2016) suggests that for Fabric Filters or Electrostatic Precipitators operated in combination with FGD techniques, an average at boiler plants a mercury removal rate of 75% or 90% to 95% in the additional presence of SCR can be obtained (EC, 2008, 2016).

26 Although no major industrial country has formally adopted regulatory limits for mercury emissions from thermal power plants, such limitations where under consideration in the United States and European Union as of 2008. Future updates of these EHS Guidelines will reflect changes in the international state of practice regarding mercury emissions prevention and control. In December 2011 the U.S. Environmental Protection Agency (EPA) announced standards to limit mercury (Hg), acid gases and other toxic pollution from power plants (US EPA, 2011). There are two broad approaches to mercury control in the US: activated carbon injection and multipollutant control (i.e., enhancing Hg capture in control devices designed to remove PM, SO2, or NOx). Activated carbon injection increases the amount of particulate matter requiring disposal but can achieve mercury capture rates of up to 95.5 percent (US EPA, 2005). The EU IED does not set statutory limits for mercury or other heavy metals. The EU Final Draft BAT Reference (BREF) note (2016) provides typical mercury removal efficiencies of activated carbon injection (90 percent on average) and existing control technologies designed for controlling pollutants other than mercury, such as fabric filters (average 40 percent Hg removal) and wet scrubber FGD systems (reported 30–50 percent Hg removal) (EC, 2016).

27 Airshed is considered degraded if relevant ambient air quality standards (as defined in the General EHS Guidelines) are exceeded; determination of whether the airshed is degraded (and thus whether offset provisions should be considered) is carried out separately for each pollutant under consideration.
Project sponsors who cannot engage in the negotiations necessary to put together an offset agreement (for example, due to the lack of the local or national air quality management framework) should consider the option of relying on an appropriate combination of using cleaner fuels, more effective pollution controls, or reconsidering the selection of the proposed project site. The overall objective is that the new thermal power plants should not contribute to deterioration of the already degraded airshed.

**Energy Efficiency and GHG Emissions**

27. 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. Project developers should consider opportunities to minimize potential emission of greenhouse gases from the outset of thermal power plant design. Opportunities include strategic choices (e.g., choice of fuel: coal, gas, oil, renewables) and from a specific level (type of plant).

22-28. Recommendations to avoid, minimize, and offset emissions of carbon dioxide from new and existing thermal power plants include, among others:

- Use of less carbon intensive fossil fuels (i.e., fuel that contains less carbon containing fuel per unit of calorific value—gas is less than oil and oil is less than coal) or co-firing with low carbon neutral fuels (i.e., biomass, which is considered carbon-neutral if produced in a sustained yield without consideration of energy used for harvesting, processing and transportation);
- Use of combined heat and power plants (CHP) where feasible;
- 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 subject to be in top quartile of the country/region average of the same fuel type and power plant size. Its technical suitability for the application and financial feasibility. Rehabilitation of existing facilities must achieve significant improvements in efficiency. Typical CO₂ emissions performance of different fuels / technologies are presented below in Table 4;
- Consider efficiency-relevant trade-offs between capital and operating costs involved in the use of different technologies. For example, supercritical plants may have a higher capital cost energy conversion efficiency than subcritical plants for the same capacity, but lower operating costs. On the other hand, characteristics of existing combined cycle gas turbine (CCGT) plants have a higher energy conversion efficiency than simple cycle plants, and CHP have higher energy conversion efficiency than power only plants. Other elements of the plant can also affect efficiency such as steam cycle parameters (e.g., pressure and temperature) for power plants based on the steam Rankine cycle, cooling and future size of the grid may impose limitations in plant size abatement technologies, electrical efficiency (e.g., electrical motors for fans) and hence technological choice. These tradeoffs need to be fully examined in the EA;
- Use of high performance monitoring and process control techniques, good design and maintenance of the combustion system so that initially

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28 See Section 1.2 of the General EHS Guidelines.
designed efficiency and GHG emission performance can be maintained;

- Where feasible, arrangement of emissions offsets (including the Kyoto Protocol’s flexible mechanisms and the voluntary carbon market), including reforestation, afforestation, or capture and storage of CO₂ 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., such as fuel supply, proximity to load centers, potential for off-site use of waste heat, or use of nearby waste gases (blast furnace gases or coal bed methane) as fuel—etc)—and

- Where applicable laws do not include a carbon management framework, consideration should be given to participation in voluntary greenhouse gas emission management mechanisms (e.g., trading schemes), or high-quality emissions offsets.

29. During the development of thermal power projects, proponents should consider alternative solutions including technical suitability and trade-offs between capital and operating costs involved in the use of different technologies with documented reasoning of why the selected option is the most feasible. For example, supercritical plants may have a higher capital cost than subcritical plants for the same capacity, but lower operating costs. New facilities should be aimed to be in the top quartile of energy efficiency for the country/region average plant of the same fuel type and capacity. Rehabilitation of existing facilities must achieve significant improvements in efficiency. Plants should use high performance monitoring and process control techniques, good design, and maintenance of the combustion system, so that initially designed efficiency, and GHG emission performance can be maintained.

30. Typical CO₂ emissions for different fuels/technologies are presented as a guide in Table 4. The values in Table 4 are indicative and are not intended to be used as benchmarks, as regional performance varies (for example due to ambient temperature differences).

31. New thermal coal power stations with a combined net electrical generating capacity at or over 300MWe should evaluate Carbon Capture and Storage Readiness (CCR) by assessing if (a) suitable storage or reuse options are

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29. The application of carbon capture and storage (CCS) from thermal power projects is still in experimental stages worldwide although consideration has started to be given to CCS-ready design. Several options are currently under evaluation including CO₂ storage in coal seams or deep aquifers and oil reservoir injection for enhanced oil recovery.

30. Required in Europe under Directive 2010/75/EU on industrial emissions (integrated pollution prevention and control) (Art 36). In the UK, CCR requirements apply to power stations with an electrical generating capacity at or over 300MW and of a type covered by the EU Large Combustion Plant Directive. CCR is in different stages of development worldwide; as of 2015 many countries including India, Italy and South Africa are considered to be ‘making progress’ by the Global CCS Institute (GCCSI, 2015), the UK, Australia and China are ‘well advanced’ and Brazil, Norway and Northern America are ‘prepared for large scale storage.’
available, (b) transport facilities are technically and economically feasible, (c) it is technically and economically feasible to retrofit for carbon dioxide capture.  

32. Table 4(B) presents typical efficiency penalties for different carbon capture technologies at thermal power plants.

Water Consumption and Aquatic Habitat Alteration

33. Condensing steam turbines used with boilers and heat recovery steam generators (HRSG) used in combined cycle gas turbine units require a cooling system to condense steam used to generate electricity. Typical cooling systems used in thermal power plants may include: (i) once-through cooling system where sufficient cooling water and receiving surface water are available; (ii) closed circuit wet (evaporative) cooling system; and (iii) closed circuit dry cooling system (e.g., air cooled condensers).

34. Thermal power plants are likely to be affected by the impacts of climate change since they are often: (i) located in areas with heightened sensitivity to climate change (such as in coastal zones and on estuaries); (ii) operated over a long period (20 years or more); (iii) reliant on fuel supplies that could be disrupted; and, (iv) reliant on water as an integral part of generation. Climate change can heighten constraints on water resources through altered precipitation patterns (e.g., droughts depleting water resources for cooling) and average temperatures thereby limiting the heat absorbing capacity of the water course, and therefore power generating capacity. A project’s vulnerability to climate change should be screened and, if vulnerable (for example projects in regions where water resources are already limited), the EA should assess climate resilience in terms of current and future water availability, temperature and heat absorbing capacity of the water course. The outcome of this assessment may influence project design to reduce the project’s climate vulnerability. For example, power generation in an arid area may use dry rather than evaporative cooling.

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31 Under the Clean Technology Fund (CTF) and many lenders’ coal fired power generation sector policies, a project needs to be developed in line with the “CCS Ready” criteria (e.g., CTF criteria). These conditions match the provisions of EU Policy (EC, 2009) and GCCSI guidance on CCS Ready (GCCSI, 2010). They are also consistent with the conclusions of the IPPC Fourth Assessment Report (IPCC, 2011).


33 For example, the European EIA Directive 2011/92/EU (as amended by Directive 2014/52/EU) requires assessment of the impact of projects on climate change (for example greenhouse gas emissions) and their vulnerability to climate change.

34 For example, the European EIA Directive 2011/92/EU (as amended by Directive 2014/52/EU) requires assessment of the impact of projects on climate change (for example greenhouse gas emissions) and their vulnerability to climate change.
### Table 4 – Typical CO$_2$ emissions performance of new thermal power plants

Thermal power plant efficiency and CO$_2$ emissions performance are dependent on a number of factors including, but not limited to, fuel type, technology, unit size, local climatic conditions, altitude and cooling technology. Values presented in this table are indicative and, due to the degree of variation in power plant characteristics, may not be directly comparable to actual new facilities. For this reason, values should not be interpreted as a benchmark or limit value and are for guidance only.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Technology</th>
<th>Efficiency (%) (source no. in brackets)</th>
<th>Details and reason for range of values</th>
<th>CO$_2$ (g/kWh) (source no. in brackets)</th>
<th>Details and reason for range of values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>Ultra-Supercritical</td>
<td>NDA</td>
<td>39-48 (1,2,4,5,13,C1)</td>
<td>NDA / Fuel type (ignite-bituminous)</td>
<td>676-934 (1,2,4,C2)</td>
</tr>
<tr>
<td></td>
<td>Supercritical</td>
<td>NDA</td>
<td>40-46 (2,4,5,7,12,15,C1)</td>
<td>NDA / Fuel type (ignite-bituminous)</td>
<td>NDA / Fuel type (bituminous-lignite)</td>
</tr>
<tr>
<td></td>
<td>Subcritical</td>
<td>37-39 (2,5,17,C1)</td>
<td>38-43 (2,4,5,7,12,17,C1)</td>
<td>Unit size, fuel type / Fuel type, region</td>
<td>951-1362 (2,C2)</td>
</tr>
<tr>
<td></td>
<td>IGCC</td>
<td>NDA</td>
<td>41-50 (1,2,4,5,7,12,C1)</td>
<td>NDA / Fuel type, region</td>
<td>NDA / Fuel type, region</td>
</tr>
<tr>
<td>Gas</td>
<td>CCGT</td>
<td>Simple Cycle</td>
<td>41-56 (9)</td>
<td>NDA / Unit size</td>
<td>361-488 (C2)</td>
</tr>
<tr>
<td></td>
<td>Boiler</td>
<td>Reciprocating Engine</td>
<td>30-45 (5,6,9,C1)</td>
<td>Unit size / Unit size</td>
<td>448-673 (6,C2)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>38-49 (3,5,10,C1)</td>
<td>Unit size and configuration / NDA</td>
<td>481-505 (C2)</td>
</tr>
<tr>
<td>Oil</td>
<td>CCGT</td>
<td>Simple cycle</td>
<td>32 (6,C1)</td>
<td>NDA</td>
<td>412-531 (C2)</td>
</tr>
<tr>
<td></td>
<td>Reciprocating Engine</td>
<td>38-47 (3,10,16,C1)</td>
<td>36 (16)</td>
<td>NDA</td>
<td>NDA</td>
</tr>
</tbody>
</table>

### Efficiency: %Gross, LHV

| Coal | Ultra-Supercritical | NDA | 47 (11) | NDA / Based on 500MWe PC plant | 728-777 (C2) |
|      | Supercritical | NDA | 44 (11) | NDA / Based on 500MWe PC plant | NDA / None given |
|      | Subcritical | NDA | 41-42 (11) | NDA / Unit size / 300MWe-500MWe | NDA / None given |
|      | IGCC | NDA | 47-48 (11) | NDA / Unit size, coal slurry, entrained bed | NDA / None given |
| Gas  | CCGT | Simple Cycle | 34 (12) | NDA | NDA / Based on 300MWe unit, 150MWe unit / 300MWe unit |
|     | Reciprocating Engine | 45-49 (8,10) | 36 (12) | NDA | NDA / Based on 300MWe unit, 150MWe unit / 300MWe unit |
| Oil  | CCGT | NDA | 51 (12) | NDA | NDA / Based on 300MWe unit, 150MWe unit / 300MWe unit |

For CO$_2$ emissions, details and reason for range of values:

- Ultra-Supercritical
- Supercritical
- Subcritical
- IGCC
- CCGT
- Simple Cycle
- Reciprocating Engine
- Oil

### Efficiency: %Net, LHV

- Ultra-Supercritical
- Supercritical
- Subcritical
- IGCC
- CCGT
- Simple Cycle
- Reciprocating Engine
- Oil

Details and reason for range of values:

- Plant efficiency / NDA
- Plant efficiency / NDA
- Plant efficiency / NDA
- Plant efficiency / NDA
- Plant efficiency / NDA
- Plant efficiency / NDA
- Plant efficiency / NDA
- Plant efficiency / NDA
## THERMAL POWER PLANTS

### Environmental, Health, and Safety Guidelines

**DRAFT FOR SECOND PUBLIC CONSULTATION—MAY/JUNE 2017**

### Simple cycle

<table>
<thead>
<tr>
<th>Source (Ref)</th>
<th>Simple cycle</th>
<th>Reciprocating Engine</th>
<th>Boiler</th>
</tr>
</thead>
<tbody>
<tr>
<td>World Bank (2006a)</td>
<td>NDA</td>
<td>41 (12)</td>
<td>NDA</td>
</tr>
<tr>
<td>European Commission (2016)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>IEA (2012)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>European Commission (2013)</td>
<td>NDA</td>
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</tr>
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<td>Parsons Brinckerhoff (2009)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>US DOE/NETL (2013)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>Wartsila product quotes</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>Gas Turbine World (2015)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>Review of manufacturer data (Wartsila and MAN)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>ESMA (2007)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>World Energy Council (2013)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>US EPA (2010)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>Gas Turbine Association (2014)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>Review of manufacturer data (Foster Wheeler)</td>
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<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>Inter-American Development Bank (2012)</td>
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<td>NDA</td>
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<tr>
<td>World Bank (2008)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>DUKES (2016)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>IPCC (2016)</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>PC = pulverized coal-fired</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>LFO = Light fuel-oil</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
<tr>
<td>HFO = Heavy fuel-oil</td>
<td>NDA</td>
<td>NDA</td>
<td>NDA</td>
</tr>
</tbody>
</table>

### Notes:

- **C1 = Calculated values.** Where there is a reference for plant efficiency for a certain fuel and technology type on an HHV basis, a conversion has been calculated to ensure that the reference is replicated on the corresponding LHV basis. The following equation has been used in the conversion:

  \[
  \text{HHV efficiency} = \text{LHV efficiency} \times \left(\frac{100}{\text{HHV of the fuel / LHV of the fuel}}\right) \times 100
  \]

  For example, the efficiency expressed in HHV terms of an oil fired simple cycle plant of 32% on a LHV basis is as follows:

  \[
  \text{HHV efficiency} = 32 \times \left(\frac{100}{(43.4 \text{ GJ/t})/1000}\right) \times 100 = 30 \%
  \]

  Calorific values were sourced from the DUKES (18) report.

- **C2 = Calculated values.** For categories of plant where it was not possible to obtain specific gCO₂/kWh values from the same sources as the efficiency, the gCO₂/kWh values have been calculated based on the efficiency range of the plant, using standard IPCC (source 19) factors for CO₂ emissions and the following equation:

  \[
  \frac{\text{gCO}_2}{\text{kWh}} = \frac{(3.6 \times \text{Efficiency as decimal} \times 1000 \times \text{fuel factor} \text{ in kgCO}_2/TJ)}{1000}
  \]

  For example, the gCO₂/kWh for a 33% efficiency boiler firing lignite is calculated as follows:

  \[
  \frac{\text{gCO}_2}{\text{kWh}} = \frac{(3.6 \times 0.33 \times 1000)}{1000} \approx 1.103 \text{ gCO}_2/\text{kWh}
  \]

- **Ranges presented for coal are predominantly due to variation in coal type** (where stated); coals with a higher moisture content and lower volatile matter content will typically emit more CO₂ per unit energy generated i.e., plant operating with lower quality coals such as lignite/brown coal will typically have lower efficiencies and higher CO₂ emissions than a like-for-like plant firing better quality bituminous coals.

- **Where there are more than two references for a range of values, the references for the highest and lowest values in the range have been presented in bold.** Where the range is a result of a C1 or C2 calculation this is also presented in bold.

- **Ultra-supercritical, supercritical and subcritical technologies are defined by their pressure and temperature.** Refer to Table A-1, Annex A for a summary.

- **NDA = No data available, i.e., at the time of writing no publicly available, referenceable literature was found for that specific category of plant technology, fuel, size or efficiency basis.** This is not intended to preclude consideration of these options and simply indicates where robust source information was not available.

- **It is important to note that the values in this table have been obtained from a range of sources and it may not be appropriate to compare between them, e.g., comparing gross values with net values for the same technology/fuel. Additionally, in some cases professional judgement has been employed when selecting sources.** This underlines the fact that this table includes ‘typical’ values, not benchmarks, as individual values are dependent on a number of project-specific factors that may not be directly comparable. Users of this table are encouraged to refer directly to the sources for further information on the specific values presented and to undertake their own assessments.
Combustion facilities using once-through cooling systems require large quantities of water which are discharged back to receiving surface water with elevated temperature. Water is also required for boiler makeup, auxiliary station equipment, ash handling, and FGD systems. The withdrawal of such large quantities of water has the potential to compete with other important water uses such as agricultural irrigation or maintaining other ecosystems services. Withdrawal and discharge with elevated temperature and chemical contaminants such as biocides or other additives, if used, may affect aquatic organisms, including phytoplankton, zooplankton, fish, crustaceans, shellfish, and many other forms of aquatic life. Aquatic organisms drawn into cooling water intake structures are either impinged on components of the cooling water intake structure or entrained in the cooling water system itself. In the case of either impingement or entrainment, aquatic organisms may be killed or subjected to significant harm. In some cases (e.g., sea turtles), organisms are entrapped in the intake canals. There may be special concerns about the potential impacts of cooling water intake structures located in or near habitat areas that support threatened, endangered, or other protected species or where local fishery is active.

<table>
<thead>
<tr>
<th>Capture technology</th>
<th>Post-combustion</th>
<th>Pre-combustion (IGCC)</th>
<th>Oxy-combustion</th>
<th>Natural gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ultra-Subcritical</td>
<td>37.6 – 42.7</td>
<td>33.1</td>
<td>31.9</td>
<td>48.4</td>
</tr>
<tr>
<td>Subcritical</td>
<td>36.9 – 38.3</td>
<td>36.9</td>
<td>36.9</td>
<td>48.4</td>
</tr>
<tr>
<td>IGCC</td>
<td>39.1 (w/o CCS)</td>
<td>39.1 (w/o CCS)</td>
<td>39.1 (w/o CCS)</td>
<td>39.1 (w/o CCS)</td>
</tr>
</tbody>
</table>

Source: Adapted from IEA CCS Technology Roadmap, 2013

<table>
<thead>
<tr>
<th>Efficiency (% Net, HHV)</th>
<th>CO₂ (g/kWh – Gross)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td></td>
</tr>
<tr>
<td>Ultra-Subcritical</td>
<td>676 – 795</td>
</tr>
<tr>
<td>Subcritical</td>
<td>756 – 836</td>
</tr>
<tr>
<td>IGCC</td>
<td>800 – 862</td>
</tr>
</tbody>
</table>

The availability of water and impact of water use may affect the choice of FGD system used (i.e., wet vs. semi-dry).

For example, maintaining the quantity, frequency, timing, and quality of water and sediment flows necessary to sustain downstream freshwater and estuarine ecosystems and the human livelihoods and well-being that depend on them.
### Efficiency (% Net, LHV)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Process Description</th>
<th>Ultra-supercritical</th>
<th>Supercritical</th>
<th>Subcritical</th>
<th>IGCC</th>
<th>IGCC+CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal (*3)</td>
<td>42 (Ultra-supercritical)</td>
<td>40 (Supercritical)</td>
<td>30—38 (Subcritical)</td>
<td>46 (IGCC)</td>
<td>38 (IGCC+CCS)</td>
<td>811</td>
</tr>
<tr>
<td>Coal and Lignite (*4, *7)</td>
<td>42–47 (Coal-FC)</td>
<td>&gt;41 (Coal-FBC)</td>
<td>42–46 (Lignite-FC)</td>
<td>&gt;40 (Lignite-FBC)</td>
<td><em>(5)</em> 725–792 (Net)</td>
<td>=831 (Net)</td>
</tr>
<tr>
<td>Oil (*4, *7)</td>
<td>40–45 (HFO/LFO Reciprocating Engine)</td>
<td><em>(6)</em> 449–505 (Net)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Efficiency (% Gross, LHV)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Process Description</th>
<th>Ultra-supercritical</th>
<th>Supercritical</th>
<th>Subcritical</th>
<th>IGCC</th>
<th>IGCC+CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal (*5, *7)</td>
<td>47 (Ultra-supercritical)</td>
<td>44 (Supercritical)</td>
<td>41.42 (Subcritical)</td>
<td>47.48 (IGCC)</td>
<td><em>(5)</em> 725</td>
<td>774</td>
</tr>
<tr>
<td>Oil (*5, *7)</td>
<td>43 (Reciprocating Engine)</td>
<td><em>(5)</em> 648</td>
<td>680</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas (*6)</td>
<td>34 (Simple Cycle GT)</td>
<td><em>(6)</em> 594</td>
<td>396</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Conventional intake structures include traveling screens with relative high through-screen velocities and no fish handling or return system. Measures to prevent, minimize, and control environmental impacts associated with water withdrawal should be established based on the results of a project EA, considering the availability and use of water resources locally and the ecological characteristics of the project affected area. Recommended management measures to prevent or control impacts to water resources and aquatic habitats include:

- Conserving water resources, particularly in areas with limited water resources, by:
  - Use of a closed-cycle, recirculating cooling water system (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. Once-through cooling water systems may be acceptable if compatible with the hydrology and ecology of the water source and the receiving water and may be the preferred or feasible alternative for certain pollution control technologies such as seawater scrubbers.
  - Use of dry scrubbers in situations where these controls are also required or recycling of wastewater in coal-fired plants for use as FGD makeup.
  - Use of air-cooled systems.

- Reduction of maximum through-screen design intake velocity to 0.5 ft/s (or 0.15 m/s).

- Reduction of intake flow to the following levels including an allowance for altered water requirements and water availability due to climate change:
  - For freshwater rivers or streams to a flow sufficient to maintain resource use (i.e., irrigation and fisheries) as well as biodiversity during annual mean low flow conditions.
  - For lakes or reservoirs, intake flow must not disrupt the thermal stratification or turnover pattern of the source water.
  - For estuaries or tidal rivers, reduction of intake flow to 1% of the tidal excursion volume.

- If there are threatened, endangered, or other protected species or if there are fisheries within the hydraulic zone of influence of the intake, reduction of impingement and entrainment of fish and shellfish by the installation of technologies such as barrier nets (seasonal or year-round), fish handling and return systems, fine mesh screens, wedgewire screens, and aquatic filter barrier systems. Examples of operational measures to reduce

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24-36. The velocity generally considered suitable for the management of debris is 1 fps [0.30 m/s] with wide mesh screens; a standard mesh for power plants of 3/8 in (9.5 mm).

36 For additional information, refer to Schimmoller (2004) and USEPA (2001).

37 Wet-recirculating or closed looped systems reuse cooling water in a second cycle rather than immediately discharging it back to the original water source. Most commonly, wet-recirculating systems use cooling towers to expose water to ambient air. Some of the water evaporates; the rest is then sent back to the condenser in the power plant. Because wet-recirculating systems only withdraw water to replace any water that is lost through evaporation in the cooling tower and discharged to maintain adequate cooling water quality, these systems have much lower water withdrawals than once-through systems, but tend to have higher overall water consumption due to the loss of evaporated water. Wet closed systems, as a retrofit technology, will more broadly affect a facility's operation and may trigger other environmental effects that may require mitigation of their own. These effects may be more pronounced at an aging facility that is less efficient and more susceptible to process changes.

40 Stream flow requirements may be based on mean annual flow or mean low flow. Regulatory requirements may be 5% or higher for mean annual flows and 10% to 25% for mean low flows. Their applicability should be verified on a site-specific basis taking into consideration resource use and biodiversity requirements.
impingement and entrainment include seasonal shutdowns, if necessary, or reductions in flow or continuous use of screens. Designing the location of the intake structure in a different direction or further out into the water body may also reduce impingement and entrainment.

**Effluents**

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

**Thermal Discharges**

As noted above, thermal power plants with steam-powered generators and once-through cooling systems use significant volume of cooling water to cool and condense the for condensing steam for return to the boiler, turbine exhaust and cooling auxiliary equipment. The heated cooling water is normally discharged back to the source water (i.e., river, lake, estuary, or the ocean) or the nearest surface water body.

Due to the biological sensitivity of many aquatic organisms to water temperature, temperature increases caused by power plant discharges may have multiple impacts on aquatic ecosystems. The effects of thermal discharges on the water environment can be sub-divided into direct effects (those organisms directly affected by changes in the temperature regime) and indirect effects (those arising in the ecosystem as a result of the changes in the organisms directly affected).

The direct effects of thermal discharges on the water environment include: change to the temperature regime of the water column and, in some cases, the sediment; lethal (temperatures above the critical thermal maximum create uninhabitable conditions) and sub-lethal (inhibited biological processes and stress) responses of water body organisms to the change in temperature regime; stimulation in productivity in a range of organisms resulting in increased respiration rates; reduction in the dissolved oxygen. The indirect effects of thermal discharges on the water environment include: changes in the distribution, composition and growth rates of communities of water body organisms including fish and macroinvertebrates; impacts on the distribution of bird populations reliant on these organisms; and altered nutrient and carbon cycling.

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

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43 Langford, 1990.
44 A mixing zone is an established area where water quality standards can be exceeded as long as acutely toxic conditions are prevented and all beneficial uses, such as drinking water, fish habitat, recreation and other uses are protected. The mixing zone concept is widely used in the...
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—EA process. Thermal discharges should be designed to prevent negative impacts to the receiving water taking into account the following criteria:

- The elevated temperature areas caused by 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; and
- There should be no significant risk to human health or the environment due to the elevated temperature or residual levels of water treatment chemicals.

42. Continuous thermal discharges to semi-enclosed bodies of water such as estuaries can result in a net increase in temperature of the water column.\(^{45,46}\) When planning thermal discharges into the receiving water body, appropriate assessment of the dispersion, dilution and cooling of the effluent is important both in terms of environmental and engineering considerations. It is important to ensure the risk of heated water recirculation (whereby elevated temperature discharge is withdrawn by the intake) is prevented.

27-43. If a once-through cooling system is used for large projects (i.e., a plant with \(> 1,200\) MW\(\text{th}\) \(= 500\) MW\(\text{th}\) 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.\(^{47}\) Recommendations to prevent, minimize, and control thermal discharges include:

US, the EU and other parts of the world. Mixing zone boundaries are usually determined through a mass-balance or mathematical modelling approach. Mass-balance calculations essentially involve defining the effective volume of the receiving water and calculating the amount of a substance that can be discharged into that volume to achieve a desired concentration. Mixing zones may be spherical or elongated, turbulent or calm, stratified or diffuse depending on the specific characteristics of the effluent and the receiving water bodies. For confined waters (e.g., water bodies with narrow channels or low flow), in some countries a limit is placed upon the proportion of the channel width occupied by the mixing zone. For example, in the UK, it is recommended that the mixing zone should not occupy more than 25% of the cross-sectional area of the estuarine channel for the annual 98th percentile (i.e., it may be exceeded for no more than 2% of the time).\(^{22}\)


\(^{46}\) The rate of mixing of the discharge plume with the water column will determine the rate at which heat is dissipated. Discharges to estuaries are most likely to have reduced mixing potential, with heated effluent concentrated in a body of water that moves up and down the estuary with the ebb and flow of the tide. This can be exacerbated by stratification where heated effluents can be entrained in distinct layers in the water column. The heated effluent may reinforce stratification as the heated buoyant effluent is entrained in surface layers, increasing the temperature differential between the layers above and below the thermocline. In some situations, for example integrated power and desalination plants (Wood et al., 2010) and plants with cooling systems that utilize certain compounds to keep heat exchange surfaces clean, cooling-water discharges are of greater salinity than the receiving environment and become entrained in the lower layers of the water column.

\(^{47}\) An example model is CORMIX (Cornell Mixing Zone Expert System) hydrodynamic mixing zone computer simulation, which has been developed by the U.S. Environmental Protection Agency. This model emphasizes predicting the site- and discharge-specific geometry and
- 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); and
- 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.

44. Where thermal and waste waters both discharge into a receiving water body for a site or development area, it is important to ensure that the dispersion modelling techniques applied would be able to represent the different buoyancy from the given effluent discharge locations. Additionally, and as relevant, influences such as temperature, sunlight, tide, surge, current, wind speed and direction, and waves, should be adequately considered as part of the detailed assessment as they can influence water quality. Credible worst-case conditions/scenarios should be taken into account when undertaking water quality and environmental impact assessment.

45. If a closed wet cooling system is used, the need for thermal discharge and effluent dilution modelling should be evaluated and decided by the EA process.

46. Climate change may result in increased thermal discharges back to the source, where water temperatures are already elevated. This may result in shut down of plant and therefore assumptions on discharge volumes should be assessed in the context of climate change. Technologies that can reduce this risk should be considered, for example using alternative cooling systems such as wet closed cooling systems or air cooled condensers. Additionally, climate change could alter the thermal profile of some receiving waters. Where appropriate, water quality models should take these potential changes into account by increasing the background water temperature and air temperature to reflect the influence of climate change.

**Liquid Waste**

28. The wastewater streams in a thermal power plant include cooling tower blowdown; 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 dilution characteristics to assess the environmental effects of a proposed discharge. Other models, such as Delft3D and Mike 21, are also used in many countries.

48 A receiving water body could be a river, ocean, stream or other watercourse into which wastewater of treated effluent and the run-off from a site or a development area are discharged.

49 Climate change could lead to an increase in water temperature and air temperature, which may increase the temperature of the discharge. Additionally, more water is likely to be needed to achieve the same cooling effect. Consequently, this will result in increased thermal discharge back to the source.

50 For example CORMIX, Delft 3D, Mike 21.
and yard drains and sumps, laboratory wastes, potentially contaminated rainwater and backflush from reverse osmosis (RO) and 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. As well as fuel type, wastewater streams present will depend on the technology employed (for example whether steam-based, simple or combined cycle combustion turbine or reciprocating engine) and, where applicable, the cooling technology employed. The characteristics of the wastewaters generated depend on the ways in which the water has been used— and how the surface water is collected and drained. 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 blowdown 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). Effluent guidelines are provided in Table 5 of Section 2.0.

29.48. Recommended water treatment and wastewater conservation methods are discussed in Sections 1.3 and 1.4, respectively, of the General EHS Guidelines. In addition, recommended measures to prevent, minimize, and control wastewater effluents from thermal power plants include:

- 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.

51 Water cooling is commonly used for cooling industrial facilities such as steam electric power plants. This water does not come into contact with raw materials, products, or other wastes and when used solely for the purpose of removing heat, is known as 'non-contact cooling water'.
52 Suitable wastewater streams for reuse include gypsum wash water, which is a different wastewater stream than the FGD wastewater. In plants that produce marketable gypsum, the gypsum is rinsed to remove chloride and other undesirable trace elements.
53 For example heavy metal removal is widely undertaken in the US and European Union where permits for thermal power plants include effluent limits for metals. The application of a waste water treatment plant employing physical / chemical treatment to remove heavy metals is considered BAT (Best Available Technique) for large combustion plants in Europe (EC, 2016) in order to comply with the waste water discharge limits under the Industrial Emissions Directive (IED). In November 2015, the US EPA revised the Steam Electric Power Generating Effluent Guidelines (US EPA, 2015) to regulate discharges of heavy metals, reflecting the impact of changing technologies on the composition of wastewater streams since the regulations were last amended in 1982, US EPA guidance also recommends physical / chemical precipitation to remove heavy metals to permitted discharge levels (US EPA, 2009).
54 Deposits dislodged by sootblowing operations will either fall into the boiler ash hoppers or be entrained in the flue gases and captured in the
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;\(^{55}\)
- Use of SO\(_x\) 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; and
- 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.

**Sanitary Wastewater**

30.49. Sewage and other wastewater generated from washrooms, etc. are similar to domestic wastewater. Impacts and management of sanitary wastewater is addressed in Section 1.3 of the General EHS Guidelines.

**Solid Wastes**

50. 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.\(^{56}\) The large-volume coal combustion \( \text{Solid} \) wastes (CCW) are fly ash, bottom ash, boiler slag, and FGD sludge—although biomass contains less sulfur than coal and therefore FGD may not be necessary when using biomass, coal mill rejects/pyrites (depending on the fuel used), cooling tower sludge, wastewater treatment sludge and water treatment sludge.

31.51. Fluidized-bed combustion (FBC) boilers, gasifiers and pyrolysers, generate fly ash and bottom ash, which is called bed ash. Fly ash removed from exhaust gases makes up 60–85% percent of the coal ash residue in pulverized-coal boilers and 20% percent in stoker boilers. Bottom ash includes slag and particles that are coarser than those of fly ash.

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\(^{55}\) If coal pile runoff will be used as makeup to the FGD system, anionic detergents may increase or create foaming within the scrubber system. Therefore, use of anionic surfactants on coal piles should be evaluated on a case-by-case basis.

\(^{56}\) For example, a 500 MWe plant using coal with 2.5% sulfur (S), 16% ash, and 30,000 kilojoules per kilogram (kJ/kg) heat content will generate about 500 tons of solid waste per day.
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 solid fuel wastes. Post-combustion dry and semi-dry scrubbing wastes or air-pollution control residues (APCR) also have a higher content of calcium and sulfate.

32-52. 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 and HFO) generate little or no solid wastes, although pre-treatment of HFO can generate significant quantities of sludge. Overall, oil combustion wastes are generated in much smaller quantities than the large-volume CCW solid fuel combustion wastes discussed above. Gas-fired thermal power plants generate essentially no solid waste because of the negligible ash content, regardless of the combustion technology.

33-53. Metals are constituents of concern in both CCW and low-volume solid wastes. For example, ash residues and the dust, particulates removed from exhaust gases and HFO sludge may contain significant levels of heavy metals and some organic compounds, in addition to inert materials.

34-54. 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, (such as polycyclic aromatic hydrocarbons (PAH) or crystalline silica), 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. Additional information about the classification and management of hazardous and non-hazardous wastes is presented in Section 1.6 of the General EHS Guidelines.

35. 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.

36-55. Recommended measures to prevent, minimize, and control the volume of solid wastes from thermal power plants include:

- Dry handling of the coal combustion solid wastes, in particular fly ash. Dry handling methods do not involve

57 Some countries may categorize fly ash as hazardous due to the presence of arsenic or radioactivity, precluding its use as a construction material. In addition, flue gas cleaning residues (APCR) and FBC residues can contain high levels of unreacted lime resulting in very high pH, and thus may be classified as hazardous.
59 For example, the US EPA (SW-846: Test Methods for Evaluating Solid Waste, Physical/Chemical Methods) or European Commission Regulation (EC) No. 1272/2008 (Annex I: Classification and labelling requirements for hazardous substances and mixtures)
surface impoundments and, therefore, do not present the ecological risks identified for impoundments (e.g., metal uptake by wildlife). Potential hazards associated with levels of, for example, pH or leachability will need to be considered and managed. Further, if there are risks of particulates from the fly ash, damping systems may be required from a safety and environmental impact perspective;

- Recycling of CCWs solid wastes in uses such as cement and other concrete products, construction fills (including structural fill, flowable fill, and road base), agricultural uses such as calcium or phosphorous 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 solid wastes can be recycled;

- If beneficial reuse is not feasible, disposal of CCW solid wastes in permitted landfills (sited to minimize contact with water during normal and abnormal weather events) 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 dustPM controls is recommended.

- Dry collection of bottom ash and fly ash, or wet collection incorporating a settling stage, 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—, which may be made worse by climate change impacts. 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; and

- HFO sludge is typically similar in general composition to the HFO used. Where HFO sludge is expected to contain potentially significant levels of hazardous materials, it should be tested at the start of plant operations and classified as hazardous or non-hazardous according to local regulations or internationally accepted approaches. If non-hazardous, HFO sludge may be incinerated on site; Detailed guidance on the storage, handling, treatment, and disposal of hazardous wastes is provided in the General EHS.

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60 Specific guidance for handling ash, including ash from biomass fired thermal plants is available from a range of sources, including the existing EHS Guideline on Waste Management Facilities, UK Environment Agency (U.K. EA, 2009, 2013 and Defra, 2012) and US EPA (US EPA, 2015).
61 See, for example, U.S. Department of Labor, Mine Safety and Health Administration regulations at 30 CFR §§ 77.214 - 77.216.
62 Additional detailed guidance applicable to the prevention and control of impacts to soil and water resources from non-hazardous and hazardous solid waste disposal is presented in the World Bank Group EHS Guidelines for Waste Management Facilities.
Hazardous Materials and Oil

37.56. 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). Major accident and spill prevention and response guidance is addressed in Sections 1.5 and 3.7 of the General EHS Guidelines.

57. In addition, recommended measures should be taken to prevent, minimize, and control hazards associated with hazardous materials—the unloading, storage and handling of hazardous materials at thermal power plants. Examples of specific hazard control measures may 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); and

• The use of enclosed conveyors, pneumatic transfer systems and silos with suitable extraction and filtration equipment to prevent the emission of PM from handling lime and limestone.

58. Specific measures are also recommended related to the handling of gaseous, liquid and solid fuels:

• Gaseous fuels: use fuel gas leak detection systems and alarms with remote operated emergency isolation valves to prevent fugitive emissions of gaseous fuels.

• Liquid fuels: to prevent water contamination, storage systems should have appropriate secondary containment as discussed in the General EHS Guidelines and procedures for the management of containment systems. The bund depth should make an allowance for rain and fire water and/or foam. Tanks should have a gauging system and a high level alarm independent of the gauging system. Pipelines should be situated in safe open areas above ground to assist with leak detection and prevent damage from vehicles and other equipment (or use double-walled pipes with locations clearly documented and marked if underground). A tertiary containment system should be provided to collect and treat surface run-off water that may have been contaminated through spillage during storage and handling.

• Solid fuels: to prevent dust releases, minimize the height of fuel drop to the stockpile using appropriate loading and unloading equipment. Water dust suppression should be used on coal stockpiles, cover stockpiles and where appropriate use belt conveyors to transport fuel to storage areas. To prevent water contamination, ensure storage areas are located on sealed surfaces with adequate drainage and water treatment of surface run-off. Biomass can potentially ferment and release carbon monoxide and other

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63 Final Draft LCP BREF note (EC, 2016).
64 Detailed guidance on bund and tertiary containment design and construction is given in CIRIA C736 (2014).
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gases; biomass should be stored in dry conditions with temperature and carbon monoxide monitoring provided. Biomass dusts can give rise to dust explosions and some wood dusts are toxic; care should be taken to minimize dust releases.  

Noise

39-59. 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.

39-60. Noise impacts, control measures, and recommended ambient noise levels are presented in Section 1.7 of the General EHS Guidelines. Additional recommended measures to prevent, minimize, and control noise from thermal power plants include:

- 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; and

- 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.

40-61. Noise propagation models 66 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 attainment of applicable community noise requirementslevel guidelines.

1.2 Occupational Health and Safety

41-62. Occupational health and safety risks and mitigation measures during construction, operation, and decommissioning of thermal power plants are similar to those at other large industrial facilities, and are addressed

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in Section 2.0 of the General EHS Guidelines. In addition, the following health and safety impacts arising from the following are of particular concern during operation of thermal power plants:

- Non-ionizing radiation;
- Heat;
- Noise;
- Confined spaces;
- Electrical hazards;
- Fire and explosion hazards;
- Chemical hazards; and
- Dust Particulate matter.

Non-Ionizing Radiation

63. Combustion facility workers may have a higher exposure to electric and magnetic fields (EMF) than the general public due to working in proximity to electric power generators, equipment, and connecting high-voltage transmission lines (including magnetic separators for solid fuels), and connecting high-voltage transmission lines. High-voltage overhead power lines typically contribute the greatest electric field impacts at a thermal power plant site, as most other potential sources on site are shielded by metallic coatings and earthed, which isolates the electric field almost totally.67

42-64. Occupational EMF exposure should be prevented or minimized through the preparation and implementation of an EMF safety program including the following components:

- Identification of potential exposure levels in the workplace, including surveys of exposure levels in new projects and the use of personal monitors during working activities;
- Training of workers in the identification of occupational EMF levels and hazards;
- Establishment and identification of safety zones to differentiate between work areas with expected elevated EMF levels compared to those acceptable for public exposure, limiting access to properly trained workers;
- Implementation of action plans to address potential or confirmed exposure levels that exceed reference occupational exposure levels—developed by international organizations such as the International Commission on Non-Ionizing Radiation Protection (ICNIRP), the Institute of Electrical and Electronics Engineers (IEEE).68—Personal exposure monitoring equipment should be set to warn of exposure levels that are below occupational exposure reference levels (e.g., 50 percent).—Action plans to address occupational exposure may include limiting exposure time through work rotation.69 Action plans to address

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67 IEC, 2011.
68 The ICNIRP exposure guidelines for Occupational Exposure are listed in Section 2.2 of this Guideline.
69 Exposure guidelines for Occupational Exposure are listed in Section 2.2 of this Guideline.
occupational exposure may include increasing the distance between the source and the worker, when feasible, or the use of shielding materials.

Heat

43-65. Occupational exposure to heat occurs during operation and maintenance of combustion units, pipes, and related hot equipment. Recommended prevention and control measures to address heat exposure at thermal power plants include:

- Regular inspection and maintenance of pressure vessels and piping;
- Provision of adequate ventilation in work areas to reduce heat and humidity;
- Reducing the time required for work in elevated temperature environments and ensuring access to drinking water;
- Insulating and shielding surfaces where workers come in close contact with hot equipment, including generating equipment, such as combustion units, generators and pipes etc.; and
- Use of warning signs near high temperature surfaces and personal protective equipment (PPE) as appropriate, including insulated gloves and shoes.

Noise

44.66. Noise sources in combustion facilities include the turbine generators and auxiliaries; boilers and auxiliaries, such as pulverizers; diesel engines; fans and ductwork; pumps; compressors; condensers; precipitators, including rappers and plate vibrators; piping and valves; motors; transformers; circuit breakers; and cooling towers. Recommendations for reducing noise and vibration externally are discussed in Section 1.1, above. In addition, recommendations to prevent, minimize potential for hearing damage, specific locations where speech communication is important, or where audible warnings and control information announcements need to be heard should be considered. Occupational noise exposures exposure management guidance, including noise limits, is provided in thermal power plants include Section 2.3 of the General EHS Guidelines.

- Provision of sound-insulated control rooms with noise levels below 60 dBA;20
- Design of generators to meet applicable occupational noise levels;
- Identify and mark high noise areas and require that personal noise protecting gear is used all the time when working in such high noise areas (typically areas with noise levels >85 dBA).

20. Depending on the type and size of the thermal power plants, distance between control room and the noise emitting sources differs. CSA Z107.58 provides design guidelines for control rooms as 60 dBA. Large thermal power plants using steam boilers or combustion turbines tend to be quieter than 60 dBA. Reciprocating engine manufacturers recommend 65 to 70 dBA instead of 60 dBA (Euromot Position as of 9 May 2008). This guideline recommends 60 dBA as GIIP, with an understanding that up to 65 dBA can be accepted for reciprocating engine power plants if 60 dBA is economically difficult to achieve.
Confined Spaces

45.67. Specific areas for confined space entry may include coal solid fuel ash containers, turbines, condensers, and cooling water towers (during maintenance activities). Recommend confined space entry procedures are discussed in Section 2.8 of the General EHS Guidelines.

68. During storage most types of biomass off-gas i.e., biomass emits different types of gas including CO, CO₂ and CH₄ as well as volatile organic compounds (such as aldehydes and ketones). CO, CO₂ and CH₄ will result in O₂ depletion and can be poisonous; therefore, well ventilated storage of biomass needs to be considered. Emission of aldehydes is a health issue; certain aldehydes cause skin and upper airways irritation.

Electrical Hazards

46.69. Energized equipment and power lines can pose electrical hazards for workers at thermal power plants. Electrical hazards management guidance is provided in Section 2.3 of the General EHS Guidelines. Recommended measures to prevent, minimize, and control electrical hazards at thermal power plants include:

- Consider installation of hazard warning lights inside electrical equipment enclosures to warn of inadvertent energization;
- Use of voltage sensors prior to and during workers' entrance into enclosures containing electrical components;
- Deactivation and proper grounding of live power equipment and distribution lines according to applicable legislation and guidelines whenever possible before work is performed on or proximal to them; and
- Provision of specialized electrical safety training to those workers working with or around exposed components of electric circuits. This training should include, but not be limited to, training in basic electrical theory, proper safe work procedures, hazard awareness and identification, proper use of PPE, proper lockout/tagout procedures, first aid including CPR, and proper rescue procedures. Provisions should be made for periodic retraining as necessary.

Fire and Explosion Hazards

47.70. Thermal power plants store, transfer, and use large quantities of fuels; therefore, careful handling is necessary to mitigate fire and explosion risks. In particular, fire and explosion hazards increase as the particle size of coal solid fuel is reduced. Particle sizes of coal solid fuel that can fuel a propagating explosion occur within thermal dryers, cyclones, baghouses, pulverized-fuel systems, grinding mills, and other process or conveyance equipment. Fire and explosion prevention management guidance is provided in Section 2.1 and 2.4 of the General EHS
Guidelines. Recommended measures to prevent, minimize, and control physical hazards at thermal power plants include:

- Use of automated combustion and safety controls;
- Proper maintenance of boiler safety controls;
- Implementation of startup and shutdown procedures to minimize the risk of suspending hot coal particles (e.g., in the pulverizer, mill, and cyclone) during startup;
- Regular cleaning of the facility to prevent accumulation of coal dust/solid fuel PM (e.g., on floors, ledges, beams, and equipment);
- Removal of hot spots from the coal stockpile (caused by spontaneous combustion) and spread until cooled, never loading hot coal into the pulverized fuel system; and
- Use of automated systems such as temperature gauges or carbon monoxide sensors to survey solid fuel storage areas to detect fires caused by self-ignition and to identify risk points.

Chemical Hazards

48-71. Thermal power plants utilize hazardous materials, including ammonia for NOx control systems, and chlorine gas for treatment of cooling tower and boiler water. Guidance on chemical hazards management is provided in Section 2.4 of the General EHS Guidelines. Additional, recommended measures to prevent, minimize, and control physical hazards at thermal power plants include:

- Consider generation of ammonia on site from urea or use of aqueous ammonia in place of pure liquefied ammonia;
- Consider use of sodium hypochlorite in place of gaseous chlorine.

Dust

Dust Particulate Matter (PM)

49-72. PM is generated in handing solid fuels, additives, and solid wastes SFCW (e.g., ash). Dust PM may contain silica (associated with silicosis), arsenic (skin and lung cancer), coal dust (black lung), biomass dust (asthma and cancer) and other potentially harmful substances. Dust PM management guidance is provided in the Section 2.1 and 2.4 of the General EHS Guidelines. Recommended measures to prevent, minimize, and control occupational exposure to dust PM in thermal power plants include:

- Use of dust PM controls (e.g., exhaust ventilation) to keep dust PM below applicable guidelines (see Section 2) or wherever free silica levels in airborne dust PM exceed 1 percent; and
- Regular inspection and maintenance of asbestos containing materials (e.g., insulation in older plants may contain asbestos) to prevent airborne asbestos particles.
1.3 Community Health and Safety

50-73. Many community health and safety impacts during the construction, operation, and decommissioning of thermal power plant projects are common to those of most infrastructure and industrial facilities and are discussed in Section 3.0 the General EHS Guidelines. In addition to these and other aspects covered in Section 1.1, the following community health and safety impacts may be of particular concern for thermal power plant projects:

- Water Consumption; and
- Traffic Safety.

74. Potential risks and impacts of accidental discharges due to extreme conditions (e.g., earthquakes or system failure) should be assessed as part of the EA process. Developers should establish emergency response plans to ensure effective management of residual risks as necessary.

75. In addition, visible plumes from thermal power plant stacks can be of concern to local communities and therefore may require assessment and explanation during stakeholder consultations.

Water Consumption

51-76. Boiler units require large amounts of cooling water for steam condensation and efficient thermal operation. The cooling water flow rate through the condenser is by far the largest process water flow, normally equating to about 98 percent of the total process water flow for the entire unit. In a once-through cooling water system, water is usually taken into the plant from surface waters, but sometimes ground waters or municipal supplies are used. Power plants may use a range of cooling methods depending on the availability of water. The potential effects of water use should be assessed, as discussed in Section 3.1 of the General EHS Guidelines, to ensure that the project does not compromise the availability of water for personal hygiene, agriculture, recreation, and other community needs.

Traffic Safety

52-77. Operation of a thermal power plant will increase traffic volume, in particular for facilities with fuels transported via land and sea, including heavy trucks carrying fuel, additives, etc. The increased traffic can be especially significant in sparsely populate areas where some thermal power plants are located. Prevention and control of traffic-related injuries are discussed in Section 3.4 of the General EHS Guidelines. Water transport safety is covered in the EHS Guidelines for Shipping.

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71 See sections on “Energy Efficiency and GHG Emissions” (cooling technologies will impact the efficiency of the plant) and “Water Consumption and Aquatic Habitat Alteration”: Traditionally, most power plants have used evaporative cooling towers where sufficient water supplies are available. In these systems, the cooling circuit accounts for about 98 percent of the site process water usage, which in turn might be expected to be around 0.3 to 0.4kg/sec for each MW(th) of plant thermal input. Alternatively, subject to environmentally acceptable temperature rises, plants near to rivers, lakes and coasts can use once-through cooling systems which have no net water usage. Where water is in short supply, the use of air-cooled condensers (ACCs) may be considered, which can cut the power plant water usage to 0.006 to 0.008kg/sec per MW(th) of plant thermal input.
2.0 Performance Indicators and Monitoring

2.1 Environment

Emissions and Effluent Guidelines

Effluent guidelines are described in Table 5. Emissions guidelines are described in Table 6. Effluent guidelines are applicable for direct discharges of treated effluents to surface waters for general use. Site-specific discharge levels may be established based on the availability and conditions in the use of publicly operated sewage collection and treatment systems or, if discharged directly to surface waters, on the receiving water use classification as described in the General EHS Guidelines. Guideline values for process emissions and effluents in this sector are indicative of good international industry practice as reflected in standards of countries with recognized regulatory frameworks. These levels should be achieved, without dilution, at least 95 percent of the time that the plant or unit is operating, to be calculated as a proportion of annual operating hours. Deviation from these levels due to specific local project conditions should be justified in the environmental assessment (EA).

<table>
<thead>
<tr>
<th>Parameter (pollutant or pollutant property)</th>
<th>Maximum concentration (mg/L, except pH and temp)</th>
</tr>
</thead>
<tbody>
<tr>
<td>pH</td>
<td>6 – 9</td>
</tr>
<tr>
<td>TSS</td>
<td>50</td>
</tr>
<tr>
<td>Oil and grease</td>
<td>10</td>
</tr>
<tr>
<td>Free available chlorine or total residual chlorine</td>
<td>0.2</td>
</tr>
<tr>
<td>Chromium – total (Cr)</td>
<td>0.52</td>
</tr>
<tr>
<td>Copper – total (Cu)</td>
<td>0.5</td>
</tr>
<tr>
<td>Iron – total (Fe)</td>
<td>1.0</td>
</tr>
<tr>
<td>Zinc (Zn)</td>
<td>1.0</td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>0.5</td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
<td>0.1</td>
</tr>
<tr>
<td>Mercury (Hg)</td>
<td>0.005</td>
</tr>
<tr>
<td>Arsenic (As)</td>
<td>0.5</td>
</tr>
<tr>
<td>Phosphorous</td>
<td>0.5</td>
</tr>
<tr>
<td>Other corrosion inhibiting materials</td>
<td>Guideline value to be established on a case by case basis through the EA process</td>
</tr>
</tbody>
</table>

- Site specific requirement to be established by the EA.
- The effluent should result in a temperature change of no more than 3°C at the edge of a scientifically established mixing zone which takes into account ambient water quality, receiving water use, potential receptors, and assimilative capacity. The EA for a specific project may specify a more stringent temperature change guideline.
- Elevated temperature areas due to discharge of once-through cooling water (e.g., 1 Celsius above, 2 Celsius above, 3 Celsius above ambient water temperature) should be minimized by adjusting intake and outfall design through the project specific EA depending on the sensitive aquatic ecosystems around the discharge point.
- The mixing zone may be established by local regulatory agencies or through the project’s EA process. It should also be minimized as far as practicable.
54. **Emissions levels for the design and operation of each project should be established through the EA process in accordance with the basis approach set out in Section 1.1 of country legislation and the recommendations provided in this guidance document, as applied to local conditions.** General EHS Guidelines. The emissions levels selected should be justified in the EA, on the basis of ambient impacts in the context of relevant ambient air quality standards. The maximum emissions levels given here can be consistently achieved by well-designed, well-operated, and well-maintained pollution control systems. In contrast, poor operating or maintenance procedures affect actual pollutant removal efficiency and may reduce it to well below the design specification. Dilution of air emissions to achieve these guidelines is unacceptable. Compliance with ambient air quality guidelines should be assessed on the basis of good international industry practice (GIIP) recommendations.

55. As described in the General EHS Guidelines, emissions should not result in pollutant concentrations that reach or exceed relevant ambient quality guidelines and standards by applying national legislated standards, or in their absence, the current WHO Air Quality Guidelines, or other internationally recognized sources. Also, 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.

56. As described in the General EHS Guidelines, facilities or projects located within poor quality airsheds, and within or next to areas established as ecologically sensitive (e.g., national parks), should ensure that any increase in pollution levels is as small as feasible, and amounts to a fraction of the applicable short-term and annual average air quality guidelines or standards as established in the project-specific environmental assessment.

**Environmental Monitoring**

57. Environmental emissions and ambient air quality monitoring programs for this sector recommendations applicable to power plants are presented in Table 7. Monitoring data should be analyzed and reviewed at regular intervals and compared with the operating standards so that any necessary corrective actions can be taken. Examples of emissions, stack testing, ambient air quality, and noise monitoring recommendations applicable to

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22 For example, in cases where potential for acid deposition has been identified as a significant issue in the EA, plant design and operation should ensure that emissions mass loadings are effectively reduced to prevent or minimize such impacts.

23 Refer to Section 1.1 of the General EHS Guidelines for further information.

24 Ambient air quality standards are ambient air quality levels established and published through national legislative and regulatory processes, and ambient quality guidelines refer to ambient quality levels primarily developed through clinical, toxicological, and epidemiological evidence (such as those published by the World Health Organization).

25 Available at World Health Organization (WHO), http://www.who.int.


27 US EPA Prevention of Significant Deterioration Increments Limits applicable to non-degraded airsheds.

28 An airshed should be considered as having poor air quality if nationally legislated air quality standards or WHO Air Quality Guidelines are exceeded significantly.
power plants are provided in Table 7. Additional guidance on applicable sampling and analytical methods for emissions and effluents is provided in the General EHS Guidelines.
Table 6 (A) - Emission Guideline Values (in mg/Nm³ or as indicated) for Reciprocating Engine

<table>
<thead>
<tr>
<th>Combustion Technology / Fuel</th>
<th>Particulate Matter (PM)</th>
<th>Sulfur Dioxide (SO₂)</th>
<th>Nitrogen Oxides (NOₓ)</th>
<th>Dry Gas, Natural Gas O₂ Content (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reciprocating Engine</td>
<td>DA</td>
<td>DA</td>
<td>DA</td>
<td>DA</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>N/A</td>
<td>N/A</td>
<td>200 (Spark Ignition)</td>
<td>15%</td>
</tr>
<tr>
<td>Liquid Fuels (Plant &gt;50 MWth)</td>
<td>N/A</td>
<td>N/A</td>
<td>1,460 (Compression Ignition, bore size diameter [mm] &lt; 400)</td>
<td>15%</td>
</tr>
<tr>
<td>Liquid Fuels (Plant &gt;300 MWth)</td>
<td>50</td>
<td>30</td>
<td>1,850 (Compression Ignition, bore size diameter [mm] ≥ 400)</td>
<td>15%</td>
</tr>
<tr>
<td>Biofuels / Gaseous Fuels other than Natural Gas</td>
<td>50</td>
<td>30</td>
<td>2,000 (Dual Fuel)</td>
<td>15%</td>
</tr>
</tbody>
</table>

Notes:
- EA may justify more stringent or less stringent guideline values due to existing environmental, community health, technical and economic considerations (Table 1). Whilst not exceeding nationally legislated limits in all cases, the EA should demonstrate that ambient impacts from emissions are in compliance with National/EU ambient air quality standards, the requirements of Section 1.1 of the General EHS Guidelines.
- For fuels other than those specified below, the EA should justify the required emission guidelines taking account of environmental, community health, technical and economic considerations.
- The Guidelines apply to facilities operating more than a combined total of 500 hours per year (i.e., if multiple units are present, the combined total of all operational units at the facility).
- See Section 2.1 for information on how facility performance is compared with these emission guidelines.
- PM defined as total suspended particulates, consistent with EU Industrial Emissions Directive (IED) and community health guidelines.

General notes:
- MWth = Megawatt thermal input on HHV basis; N/A = not applicable; NDA = Non-degraded airshied; DA = Degraded airshied (poor air quality); Airshed should be considered as being degraded if nationally legislated air quality standards are exceeded or, in their absence, if WHO Air Quality Guidelines are exceeded significantly; S = sulfur content (expressed as a percent by mass); Nm³ is at one atmospheric pressure, 0 degree Celsius; MWth category is to apply to the entire facility consisting of multiple units that are reasonably considered to be emitted from a common stack. Guideline limits apply to facilities operating more than 500 hours per year. Emission levels should be evaluated on a one-hour average basis and be achieved 95% of annual operating hours.
- a) Compression Ignition (CI) engines may require different emission values which should be evaluated on a case-by-case basis through the EA process in accordance with Section 1.1 of the General EHS Guidelines.

Comparison of the Guideline limits with standards of selected countries / region (as of August 2008):
- Natural Gas-fired Reciprocating Engine – NOₓ:
  - Guideline limits: 200 (SI), 400 (DF)
  - UK: 100 (CI), 15% - Reduce by 90% or more, or alternatively 1.6 g/kWh
- Liquid Fuels-fired Reciprocating Engine – NOₓ (Plant >50 MWth to <300 MWth):
  - Guideline limits: 1,460 (CI, bore size diameter < 400 mm), 1,850 (CI, bore size diameter ≥ 400 mm), 2,000 (DF)

Guideline values are applicable for new facilities.
- Nationally legislated limits should be applied if they are more stringent.
Comparison of the Guideline values with standards of selected countries / region (as of January 2017):

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Technology</th>
<th>NOx Standard (SI or dual fuel)</th>
<th>SO2 Standard (Plant &gt;50 MWth)</th>
<th>PM Standard (Plant &gt;50 MWth)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas-fired Reciprocating Engine</td>
<td>EU: 75mg/Nm³ (SI or dual fuel). Note BAT indicates concentrations of 20 to 75mg/Nm³.</td>
<td>EU: BAT indicates use of low S fuel oil or the secondary-FGD (IPCC LCP BREF)</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
</tr>
<tr>
<td></td>
<td>US: 82ppmv (equivalent to 169mg/Nm³); conversion = concentration (ppm) x molecular weight of NOx (g) / molar volume at 0°C (dm³) i.e. 82ppmv x 46.1g / 22.4dm³ = 169mg/Nm³.</td>
<td></td>
<td>EU: 'low S' fuel oil is considered to be HFO with S content ≤ 1% (Liquid Fuel Quality Directive).</td>
<td>EU: No PM limits for engines.</td>
</tr>
<tr>
<td>Liquid Fuels-fired Reciprocating Engine</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No PM limits for engines.</td>
</tr>
<tr>
<td></td>
<td>US: 2g/kWh</td>
<td>US: 2g/kWh</td>
<td>US: 2g/kWh</td>
<td>US: 2g/kWh</td>
</tr>
<tr>
<td></td>
<td>India: 1,460 (Urban area &amp; ≤ 75 MWt (≈ 190MWth), Rural area &amp; ≤ 150 MWt (≈ 380MWth))</td>
<td>India: 1,460 (Urban area &amp; ≤ 75 MWt (≈ 190MWth), Rural area &amp; ≤ 150 MWt (≈ 380MWth))</td>
<td>India: 1,460 (Urban area &amp; ≤ 75 MWt (≈ 190MWth), Rural area &amp; ≤ 150 MWt (≈ 380MWth))</td>
<td>India: 1,460 (Urban area &amp; ≤ 75 MWt (≈ 190MWth), Rural area &amp; ≤ 150 MWt (≈ 380MWth))</td>
</tr>
<tr>
<td></td>
<td>UK: 300 (≥ 25 MWth),</td>
<td>UK: 300 (≥ 25 MWth),</td>
<td>UK: 300 (≥ 25 MWth),</td>
<td>UK: 300 (≥ 25 MWth),</td>
</tr>
<tr>
<td></td>
<td>India: 740 (Plant ≥300 MWth)</td>
<td>India: 740 (Plant ≥300 MWth)</td>
<td>India: 740 (Plant ≥300 MWth)</td>
<td>India: 740 (Plant ≥300 MWth)</td>
</tr>
<tr>
<td>Liquid Fuels-fired Reciprocating Engine</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
</tr>
<tr>
<td></td>
<td>US: 2g/kWh</td>
<td>US: 2g/kWh</td>
<td>US: 2g/kWh</td>
<td>US: 2g/kWh</td>
</tr>
<tr>
<td></td>
<td>India: 740 (Urban area &amp; &gt; 75 MWt (© 190MWth), Rural area &amp; &gt; 150 MWt (© 380MWth))</td>
<td>India: 740 (Urban area &amp; &gt; 75 MWt (© 190MWth), Rural area &amp; &gt; 150 MWt (© 380MWth))</td>
<td>India: 740 (Urban area &amp; &gt; 75 MWt (© 190MWth), Rural area &amp; &gt; 150 MWt (© 380MWth))</td>
<td>India: 740 (Urban area &amp; &gt; 75 MWt (© 190MWth), Rural area &amp; &gt; 150 MWt (© 380MWth))</td>
</tr>
<tr>
<td>Liquid Fuels-fired Reciprocating Engine</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
<td>EU: No limits for engines other than gas fueled engines.</td>
</tr>
<tr>
<td></td>
<td>US: 2g/kWh</td>
<td>US: 2g/kWh</td>
<td>US: 2g/kWh</td>
<td>US: 2g/kWh</td>
</tr>
<tr>
<td></td>
<td>India: 740 (Plant ≥300 MWth)</td>
<td>India: 740 (Plant ≥300 MWth)</td>
<td>India: 740 (Plant ≥300 MWth)</td>
<td>India: 740 (Plant ≥300 MWth)</td>
</tr>
</tbody>
</table>


UK: 300 (≥ 25 MWth), 150mg/Nm³; EU: No limits for engines other than gas fueled engines.

Indian: 740 (Plant ≥300 MWth, Urban area & ≤ 75 MWt (≈ 190 MWth), Rural area & ≤ 150 MWt (≈ 380 MWth)).

UK: 300 (≥ 25 MWth), 150mg/Nm³; EU: No limits for engines other than gas fueled engines.

US: Use of diesel fuel with max S of 500 ppm (0.05%); EU: Marine HFO, S content ≤ 0.1% (Liquid Fuel Quality Directive).
Notes:

- **Guideline values** are applicable for new facilities.
- Nationally legislated limits should be applied if they are more stringent.
- EA may justify more stringent or less stringent values due to ambient environment, environmental, community health, technical, and economic considerations provided there is, whilst not exceeding nationally legislated limits in all cases, the EA should demonstrate that ambient impacts from emissions are in compliance with applicable ambient air quality standards.
- For projects to rehabilitate existing facilities, case-by-case or for turbines undergoing a major overhaul, emission measurement guidelines should be established by the EA considering (i) the existing emission levels and impacts on the environment and community health, and (ii) worst economic and technical feasibility of technologies ensuring the existing emission levels to meet the Guideline values for new facilities limits. For turbines undergoing a major upgrade in technology, the possibility of reducing emission levels should be considered on a case-by-case basis.
- EA should demonstrate that emissions do not constitute a significant portion to the attainment of interlinked ambient air quality guidelines or standards, and more stringent limits may be required.

### Table 6 (B) - Emission Guideline Values (in mg/Nm³ as indicated) for Combustion Turbine

<table>
<thead>
<tr>
<th>Combustion Technology / Fuel</th>
<th>Particulate Matter (PM)</th>
<th>Sulfur Dioxide (SO₂)</th>
<th>Nitrogen Oxides (NOₓ)</th>
<th>Excess Dry Gas O₂ Content (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas (all turbine types of Unit &gt;50MWth)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>51.25 ppm (30 ppm)</td>
</tr>
<tr>
<td>Fuels other than Natural Gas - Distillate/Light Fuel Oil (Unit &gt;50MWth)</td>
<td>50</td>
<td>30</td>
<td>Use of 1% or less S fuel</td>
<td>152 ppm (74 ppm)</td>
</tr>
</tbody>
</table>

Notes:

(a) Non-natural gas gaseous fuels and HFO can vary considerably in composition and emission guidelines should be assessed on a case-by-case basis to determine what can be achieved.

**General Notes:**

- MWth = Megawatt thermal input on HHV basis;
- N/A = not applicable;
- NDA = Non-degraded airsherd; DA = Degraded airsherd (poor air quality);
- Airsherd should be considered as being degraded if nationally legislated ambient air quality standards are exceeded or if defined in their absence. If NO₂ Air Quality Guidelines or General EHS Guidelines are exceeded significantly, DA/NDA to be determined for each pollutant;
- S = sulfur content (expressed as a percent by mass);
- In the event that natural gas contains elevated sulfur levels, SO₂ emissions should be no greater than that for liquid fuels;
- Nm³ is at one atmospheric pressure, 0 degree Celsius; dry gas.
- NOₓ, mg/Nm³ to ppm conversion assumes NOₓ as NO;
- MWth category is to apply to single units;
- Guideline limits values apply to facilities operating more than a combined total of 500 hours per year.
- Emission levels should be evaluated on a one-hour-average basis and (i.e. if multiple units are present, the combined total of all operational units at the facility).

**Guideline values** should be achieved 95% of annual operating hours, down to at least 60% turbine load. See Section 2.1 for information on how facility performance is compared with these emission guidelines.

### Comparison of the Guideline values with standards of selected countries / region (as of January 2017):

- Natural Gas-fired Combustion Turbine – NOₓ:
  - EU: 50mg/Nm³ for simple cycle turbines with an efficiency above 35%; 50*η / 35 (where η = efficiency % at ISO conditions). Note BAT indicates concentrations of 10 to 50mg/Nm³ can be achieved using primary abatement measures only.
  - US: 74ppm (152mg/Nm³) (> = 15MWth and ≤ 249MWth), 15ppm (31mg/Nm³) (> = 249MWth). Note NOₓ limits in the range of 4 to 19mg/Nm³ are typically required through permitting system.
  - India: 500ppm (new plants, natural gas, >400MW), 75ppm (new plants, natural gas, >100MW but <400MW), 100ppm (new plants, natural gas, <100MW).
  - China: 50 mg/Nm³ for natural gas-fired combustion turbines.
- Liquid Fuel-fired Combustion Turbine – NOₓ:
  - EU: 50mg/Nm³;
  - US: 74ppm (152mg/Nm³) (> = 15MWth and ≤ 249MWth), 42ppm (86mg/Nm³) (> = 249MWth).
  - India: 100ppm (new plants, naphtha)
  - China: 120mg/Nm³.
- Liquid Fuel-fired Combustion Turbine – SO₂:
  - EU: S content of light fuel oil used in gas turbines below 0.1%
  - US: S content of about 0.05% (continental area) and 0.4% (non-continental area)
  - China: 100mg/Nm³.

supplemental firing units (e.g., duct burners).

- (a) Technological differences (for example the use of Aeroderivatives) may require different emissions values which should be evaluated on a case-by-case basis through the EA process but which should not exceed 200 mgNm⁻³.

Comparison of the Guideline limits PM defined as total suspended particulates, consistent with standards of selected countries / region (as of August 2008):

<table>
<thead>
<tr>
<th>Technology</th>
<th>NOx Guideline limits</th>
<th>SOx Guideline limits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas-fired Combustion Turbine</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU</td>
<td>50 (24 ppm)</td>
<td>1% or less S fuel</td>
</tr>
<tr>
<td>US</td>
<td>25 ppm (249 MMBtu/h)</td>
<td>1% or less S fuel</td>
</tr>
</tbody>
</table>

Table 6 (C) - Emission Guidelines (in mg/Nm³ or as indicated) for Boiler

Note:
- *Guidelines* Guideline values are applicable for new facilities.
- Nationally legislated limits should be applied if they are more stringent.
- EA may justify more stringent or less stringent limits if guideline values due to unique environmental, community health, technical, and economic considerations provided there is, whilst not exceeding nationally legislated limits in all cases, the EA should demonstrate that ambient impacts from emissions are in compliance with applicable ambient air quality standards.
- For fuels other than those specified below, the EA should justify the required emission guidelines taking account of environmental, community health, technical, and economic implications.
- For projects to rehabilitate existing facilities, the baseline emission requirements guidelines should be established by the EA considering (i) the existing emission levels and impacts on the environment and community health, and (ii) and economic and technical feasibility of upgrading ensuring the existing emission levels to meet the Guideline values for new facilities.

<table>
<thead>
<tr>
<th>Combustion Technology / Fuel</th>
<th>Particulate Matter (PM)</th>
<th>Sulfur Dioxide (SO₂)</th>
<th>Nitrogen Oxides (NOₓ)</th>
<th>Excess Dry gas O₂ Content (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NDA DA</td>
<td>NDA DA</td>
<td>NDA DA</td>
<td>NDA DA</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>N/A N/A</td>
<td>N/A N/A</td>
<td>N/A N/A</td>
<td>N/A DA</td>
</tr>
<tr>
<td>Other Gaseous Fuels</td>
<td>50 30</td>
<td>400 200</td>
<td>200 200</td>
<td>3%</td>
</tr>
<tr>
<td>Liquid Fuels (Plant &gt;50 MWth≤500 MWth)</td>
<td>50 30</td>
<td>1,500–400 – 1,000</td>
<td>400</td>
<td>200 3%</td>
</tr>
<tr>
<td>Liquid Fuels (Plant &gt;500 MWth≥600 MWth)</td>
<td>50 40</td>
<td>200 – 400</td>
<td>400</td>
<td>200 3%</td>
</tr>
<tr>
<td>Solid Fuels (Plant &gt;50 MWth≤500 MWth)</td>
<td>50 30</td>
<td>1,500–400 – 1,000</td>
<td>400</td>
<td>200 ≤6% Or up to 1,100 if volatile matter of fuel &lt; 10% 500</td>
</tr>
<tr>
<td>Solid Fuels (Plant &gt;500 MWth≥600 MWth)</td>
<td>50 40</td>
<td>200 – 650</td>
<td>200</td>
<td>6%</td>
</tr>
</tbody>
</table>
### General notes:

- MWth = Megawatt thermal input on HHV basis; N/A = not applicable; NDA = Non-degraded airshed; DA = Degraded airshed (poor air quality). Airshed should be considered as being degraded if nationally legislated air quality standards are exceeded or, in their absence, if WHO Air Quality Guidelines are exceeded significantly. CFB = circulating fluidized bed coal-fired; PC = pulverized coal-fired; Nm³ is at one atmospheric pressure, 0 degree Celsius.

### Comparison of the Guideline values with standards of selected countries / region (as of January 2017):

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Standard</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx</td>
<td></td>
</tr>
<tr>
<td>EU</td>
<td>100 mg/Nm³</td>
</tr>
<tr>
<td>US</td>
<td>88 mg/J gross energy output</td>
</tr>
<tr>
<td>China</td>
<td>100 mg/Nm³</td>
</tr>
<tr>
<td>PM</td>
<td></td>
</tr>
<tr>
<td>EU</td>
<td>20 mg/Nm³, 10 (&gt; 300 MWth for coal and lignite)</td>
</tr>
<tr>
<td>US</td>
<td>11 mg/J gross energy output</td>
</tr>
<tr>
<td>China</td>
<td>30 mg/Nm³</td>
</tr>
<tr>
<td>SO₂</td>
<td></td>
</tr>
<tr>
<td>EU</td>
<td>850 mg/Nm³</td>
</tr>
<tr>
<td>US</td>
<td>240 mg/Nm³</td>
</tr>
<tr>
<td>China</td>
<td>140 mg/Nm³ (=&gt; 210 MWth)</td>
</tr>
<tr>
<td>PM</td>
<td></td>
</tr>
<tr>
<td>EU</td>
<td>400 mg/Nm³ (50 – 100 MWth), 200 mg/Nm³ (&gt;300 MWth)</td>
</tr>
<tr>
<td>US</td>
<td>130 mg/J gross energy output or 97% reduction</td>
</tr>
<tr>
<td>China</td>
<td>50 – 200 mg/Nm³ (subject to location)</td>
</tr>
</tbody>
</table>

### Source:
- China (GB13223-2011), India (The Environment (Protection) Rules, 1986).
Table 7 - Typical Air Emission Monitoring Parameters / Frequency for Thermal Power Plants
(Note: Detailed monitoring programs should be determined based on EA)

<table>
<thead>
<tr>
<th>Combustion Technology / Fuel</th>
<th>Particulate Matter (PM)</th>
<th>Sulfur Dioxide (SO₂)</th>
<th>Nitrogen Oxides (NOₓ)</th>
<th>Heavy Metals</th>
<th>NOₓ</th>
<th>SO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Reciprocating Engine</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas (Plant &gt; 50 MWth Gaseous (=&gt;50MWth to &lt;100 MWth))</td>
<td>N/A</td>
<td>Continuous Automatic or Indicative</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas (Plant =&gt; 300 MWth Gaseous (=&gt;100MWth))</td>
<td>N/A</td>
<td>Continuous Automatic or Indicative</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liquid (Plant =&gt; 50 MWth to &lt;100 MWth)</td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic if FGD is used or monitor by S content</td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic</td>
<td>Annual</td>
<td></td>
</tr>
<tr>
<td>Liquid (Plant =&gt; 300 MWth to &lt;100 MWth)</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic if FGD is used or indicative</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Annually</td>
<td></td>
</tr>
<tr>
<td><strong>Biomass Combustion Turbine</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas (all turbine types of Unit &gt; 50MWth)</td>
<td>N/A</td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous or indicative</td>
<td>Continuous Automatic if impacts &gt;25% relevant ambient standards and/or airshed degraded or Passive or Manual</td>
</tr>
<tr>
<td>Fuels other than Natural Gas (Unit &gt; 50MWth to &lt;100MWth)</td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic if FGD is used or monitor by S content</td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic</td>
<td>Annual</td>
<td>N/A</td>
</tr>
<tr>
<td>Fuel Type</td>
<td>Boilers Liquid (&gt;100MWth)</td>
<td>Gaseous (=&gt;50MWth to &lt;100MWth)</td>
<td>Other Gaseous fuels (&gt;100MWth)</td>
<td>Liquid (Plant &gt;50 MWth to &lt;=100 MWth)</td>
<td>Liquid (Plant &gt;=600 MWth to &lt;=1000 MWth)</td>
<td>Solid (Plant &gt;50 MWth to &lt;=100 MWth)</td>
</tr>
<tr>
<td>-----------</td>
<td>---------------------------</td>
<td>---------------------------------</td>
<td>---------------------------------</td>
<td>--------------------------------------</td>
<td>------------------------------------------</td>
<td>--------------------------------------</td>
</tr>
<tr>
<td></td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic or Indicative</td>
<td>Annual</td>
<td>Continuous Automatic if impacts &gt;25% relevant ambient standards and/or airshed degraded or Passive or Manual</td>
<td>Continuous Automatic if impacts &gt;25% relevant ambient standards and/or airshed degraded or Passive or Manual</td>
</tr>
<tr>
<td>Boilers Liquid (&gt;100MWth)</td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic or Indicative</td>
<td>Continuous Automatic or Indicative</td>
</tr>
<tr>
<td>Gaseous (=&gt;50MWth to &lt;100MWth)</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
</tr>
<tr>
<td>Other Gaseous fuels (&gt;100MWth)</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
</tr>
<tr>
<td>Liquid (Plant &gt;50 MWth to &lt;=100 MWth)</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
<td>Continuous Automatic if FGD is used or Indicative</td>
</tr>
<tr>
<td>Liquid (Plant &gt;=600 MWth to &lt;=1000 MWth)</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
</tr>
<tr>
<td>Solid (Plant &gt;50 MWth to &lt;=100 MWth)</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
</tr>
<tr>
<td>Solid (Plant &gt;=600 MWth to &lt;=1000 MWth)</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
<td>Continuous Automatic</td>
</tr>
</tbody>
</table>

Notes:
- Continuous or indicative means "continuously monitor emissions or continuously monitor indicative parameters". Stack emission testing is to have direct measurement of emission levels to counter check the emission monitoring system.
- Ambient air monitoring is usually not required for gaseous fueled facilities <100MWth, regardless of the combustion technology.
- Automatic means an automatic analyzer installed in situ, continuously operating, that can usually output a concentration every few seconds, designed and operated in accordance to international standards and that undergoes annual calibration checks.
- Passive or manual monitoring: Passive methods such as diffusion tubes can be used to provide monthly averages. Manual methods can provide daily or weekly averages.
- Examples of indicative emissions monitoring are: NOx – Maximum combustion temperature and maximum excess oxygen level, SO2 – Sulfur content of fuel, PM – Ash content of fuel, maximum flue gas flow rate, minimum power supply to ESP or minimum pressure drop across bag filters.
- If airshed is degraded, continuous ambient monitoring of pollutants for which the airshed is degraded at a minimum of two locations, irrespective of process contributions.
- MWth = Megawatt thermal.
- MWth categories applicable to a facility with multiple units. In such cases, multiple sampling points are likely to be required.
2.2 Occupational Health and Safety

Occupational Health and Safety Guidelines

59-81. Occupational health and safety performance should be evaluated against internationally published exposure guidelines, of which examples include the Threshold Limit Value (TLV®) occupational exposure guidelines and Biological Exposure Indices (BEIs®) published by American Conference of Governmental Industrial Hygienists (ACGIH),79 the Pocket Guide to Chemical Hazards published by the United States National Institute for Occupational Health and Safety (NIOSH),80 Permissible Exposure Limits (PELs) published by the Occupational Safety and Health Administration of the United States (OSHA),81 Indicative Occupational Exposure Limit Values published by European Union member states,82 or other similar sources.

59-82. Additional indicators specifically applicable to electric power sector activities include the ICNIRP exposure limits guidelines for occupational limiting exposure to time varying electric and magnetic fields (1HZ – 100kHz) listed in Table 8. Additional applicable indicators such as noise, electrical hazards, air quality, etc. are presented in Section 2.0 of the General EHS Guidelines.

<table>
<thead>
<tr>
<th>Table 8 - ICNIRP exposure limits Reference levels for occupational exposure to time-varying electric and magnetic fields.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency</td>
</tr>
<tr>
<td>-----------</td>
</tr>
<tr>
<td>50 Hz</td>
</tr>
<tr>
<td>60 Hz</td>
</tr>
</tbody>
</table>

Source: ICNIRP Guidelines (2010) for limiting exposure to time-varying electric and magnetic fields (1HZ – 100kHz)

Source: ICNIRP (1998) : “Guidelines for limiting exposure to time-varying electric, magnetic, and electromagnetic fields (up to 300 GHz)

Accident and Fatality Rates

60-83. Projects should try to reduce the number of accidents among project workers (whether directly employed or subcontracted) to a rate of zero, especially accidents that could result in lost work time, different levels of

80 Available at: https://www.cdc.gov/niosh/npg/http://www.cdc.gov/niosh/npg/
disability, or even fatalities. The accident and fatality rates of the specific facility may be benchmarked against the performance of facilities in this sector in developed countries through consultation with published sources (e.g., US Bureau of Labor Statistics and UK Health and Safety Executive).83

Occupational Health and Safety Monitoring

61-84. The working environment should be monitored for occupational hazards relevant to the specific project. Monitoring should be designed and implemented by accredited professionals84 as part of an occupational health and safety monitoring program. Facilities should also maintain a record of occupational accidents and diseases and dangerous occurrences and accidents. Additional guidance on occupational health and safety monitoring programs is provided in the General EHS Guidelines.

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84 Accredited professionals may include Certified Industrial Hygienists, Registered Occupational Hygienists, or Certified Safety Professionals or their equivalent.
3.0 References and Additional Sources


California Division of Occupational Safety and Health. “Permissible Exposure Limits for Chemical Contaminants.” In: California Code of Regulations, Division 1, Chapter 4, Subchapter 7, Group 16, Article 107, Section 5155 “Airborne Contaminants”. http://www.dir.ca.gov/title8/ac1.pdf.


Environmental, Health, and Safety Guidelines
THERMAL POWER PLANTS
DRAFT FOR SECOND PUBLIC CONSULTATION—MAY/JUNE 2017


Ministry of Environment and Forest Notification, New Delhi, the 9th of July, 2002. Emission Standards for Diesel Engines (Engine Rating More Than 0.8 MW (800kW) for Power Plant, Generator Set Applications and Other Requirements.


Environmental, Health, and Safety Guidelines
THERMAL POWER PLANTS
DRAFT FOR SECOND PUBLIC CONSULTATION—MAY/JUNE 2017


Annex A: General Description of Industry Activities

62-85. 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 A-1, small part of the electrical energy is a generalized flow diagram of a boiler-based thermal used for parasitic loads on site to run the power plant and its associated operations, fuel systems.

63-86. Not all thermal energy can be transformed to mechanical power, according to the second law of thermodynamics. Therefore, thermal power plants also produce heat output. In the case of condensing boiler/steam turbine plants, the heat produced is at low-temperature heat. If no use is found for the heat, it is lost to the environment. If higher temperature reject heat (such as from a combustion turbine or reciprocating engine; or from modification of a steam cycle to include a steam extraction or back-pressure system) 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

64-87. Thermal power plants can be divided based on the type of combustion or gasification: into Rankine Cycle (which use boilers, turbines, condensers and feed water pumps), internal combustion reciprocating engines, and combustion turbines. In addition, combined-cycle and cogeneration systems increase efficiency by utilizing heat lost by conventional combustion systems, either for additional power or for useful heat supply. The type of system is chosen based on the loads, the availability and cost of fuels, and the energy requirement of the net electrical output to the connected electric power generation facility, grid. 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). Figure A-1, Figure A-2 and Figure A-3 respectively present generalized flow diagrams of boiler, engine and combustion turbine-based thermal power plants and associated operations.

Rankine Cycle (Boilers and Steam Turbines Turbine systems)

65-88. 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 expanding in the turbine from the high-pressure
boiler to the low-pressure condenser pressure drives the turbine blades, which in turn powers the electrical generator.

Figure A-1: Generalized Flow Diagram of a Thermal power plant (Boiler case) and Associated Operations

Note: Sorbent injection includes processes where sorbent is added with the fuel, injected in the convective pass, upstream/downstream of the economizer and upstream of the particulate collector. The sorbents used for various injection processes include limestone, lime, hydrated lime, soda ash and sodium bicarbonate as well as naturally occurring sodium carbonates and bicarbonates. Ammonia is injected in the furnace for SNCR or further downstream for SCR.

Figure A-2: Generalized Flow Diagram of a Thermal power plant (liquid fuel-fired engine case) and Associated Operations
Figure A-3: Generalized Flow Diagram of a Thermal power plant (Combined Cycle Gas Turbine (CCGT) case) and Associated Operations
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 coolant, either water or air (EC, 2013). As the steam is cooled to condensate, the condensate is transported by the boiler feedwater system back to the boiler, where it is used again. A constant flow of low-temperature cooling coolant 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 coolant is warmed. If the cooling system is an open or a once-through water system, this warm water is released back to the source water body. In a closed water 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 make-up water is required to offset the evaporative and drift 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. A recirculating system requires make-up of only a few percent compared to the flow rate of water in a once-through system, and so can be used where only borehole or local water supplies are available.

85 If groundwater is used for cooling, the cooling water is usually discharged to a surface water body.
available. Where even this water loss might be unacceptable an air cooled condenser (ACC) can be used, which does not involve a water circuit and so has no water requirement. However, ACC are significantly more expensive than water-cooled condensers and are typically only used where other options are not feasible.

67-90. Steam turbines [turbine based power plants] typically have a thermal efficiency of about 35\% in the range 27 to 47 percent, meaning that 35 percent (gross, LHV), which indicates the proportion of the heat of combustion that is transformed into electricity. The efficiency varies with plant capacity and (often correspondingly) with the steam conditions selected. The remaining 65 percent of the heat either goes up the content of the fuel is lost through a combination of stack losses (typically 8 to 10 percent), radiation and convection from the boiler to its surroundings, heat in bottom and fly ash, heat in boiler blowdown water, energy content of unburnt fuel that passes through the boiler or is discharged with the condenser cooling water (typically 55 percent).

91. As illustrated in Table 4, the overall efficiency of a steam turbine based thermal power plant is dependent on the steam conditions/technology (e.g., subcritical, supercritical or ultra-supercritical), unit size and fuel type. Classification of the technology into sub-, super-, ultra-supercritical (USC) and advanced USC depends on the steam temperature and pressure. Table A-1 presents some commonly used definitions of each of these types of steam turbine power plants. As shown there is no universal definition of the terminology for each technology, although interpretations tend towards broadly similar temperatures and pressures based on the critical point of water (221 bar and 374°C).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Temp. (°C)</td>
<td>Pressure (bar)</td>
<td>Temp. (°C)</td>
<td>Pressure (bar)</td>
</tr>
<tr>
<td>Sub-critical</td>
<td>≥600</td>
<td>&gt;221</td>
<td>&lt;374</td>
<td>&lt;221</td>
</tr>
<tr>
<td>Super-critical</td>
<td>(Mild USC)</td>
<td>&lt;600</td>
<td>≥221</td>
<td>≥374</td>
</tr>
<tr>
<td>Ultra-SC</td>
<td>&lt;700</td>
<td>&gt;221</td>
<td>&gt;221</td>
<td>&gt;221</td>
</tr>
<tr>
<td>Advanced USC(1)</td>
<td>≥600</td>
<td>&gt;221</td>
<td>&gt;221</td>
<td>&gt;221</td>
</tr>
</tbody>
</table>

(1) Note that the upper extent of current operating experience is around 600°C (main steam temperature) and that material development and demonstration is required to attain commercially proven applications at advanced USC steam conditions.

92. Coal and lignite are the most common solid fuels in boiler/steam turbine-based thermal power plants although biomass in dedicated plant or co-firing with coal is gaining increasing prominence. Heavy fuel oil is also used in some plants; and some coal plants have been converted to use natural gas in whole or in part.

68-93. Large coal-fired steam generation systems are generally 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. Typical pulverised coal types include wall/corner fired tower boilers, two-pass boilers, as well as downshot fired boilers. In fluidized-bed combustors, fuel materials are (FBC), larger fuel material dimensions can be used, which is forced by gas the flow of primary air 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, \( \text{SO}_2 \) and \( \text{NO}_x \) emissions are reduced because an in-bed \( \text{SO}_2 \) sorbent, such as limestone, can be used efficiently. Also, and because the operating temperature is relatively low, the amount of \( \text{so}_2 \) thermal \( \text{NO}_x \) gases formed is lower, production is significantly reduced than those produced when using conventional technology. In circulating FBC, the combustion flue gases from the furnace enter a cyclone arrangement which passes the finer material through the heat exchange surfaces and onto the flue gas treatment equipment for discharge via the stack, but return the coarser material to the furnace for further combustion.

69. Natural gas and liquid fuels are usually transported to thermal power plants via pipelines, although bio-oils would commonly be delivered by tanker. Coal and biomass fuels can be transported by ship, rail, barge, or truck, or conveyor to the power plant. 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 solid fuel arrives at the plant, it is unloaded to storage or directly to the stoker or hopper, typically transferred by conveyor. In transporting coal solid fuels during warmer months and in dry climates, dust PM suppression may be necessary.

70. 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, where appropriate, to reduce sulfur in the coal to meet sulfur dioxide (SO\(_2\)) emissions regulations and also reduce content of 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.

71. 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, reactivity. 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. Solid biomass fuels are already generally more reactive than coals and hence can be used with fewer preparation stages, involving only chipping/shredding.

Reciprocating Engines

72. Internal combustion engines convert the chemical energy of fuels (typically diesel fuel or, heavy fuel oil or natural gas, but increasingly also unconventional oils or gases such as biofuels and syngas) into mechanical energy in a design similar to a truck engine, and the mechanical energy, which is used to turn drive a generator. There are broadly two types of engines normally used: the engine in common use for power generation: the high- or medium-speed, four-stroke trunk piston engine and the low-speed, two-stroke crosshead engine. Both types of The four-stroke engine may operate on the air-standard diesel thermodynamic Diesel cycle—where the air/fuel mixture is ignited by the heat resulting from compression above a rising piston; or on the Otto cycle where combustion is
initiated by a spark or other high-energy source. The low-speed two-stroke engine operates exclusively on the Diesel cycle. In both cycles, 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 ignited, leading to rapid expansion which pushes the piston back along the cylinder before it returns to expel 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 typically in the range 0.05–0.2% percent for liquid fuels (although some gas or non-fossil oil fuels have zero ash content). SOx emissions are directly dependent on the sulfur content of the fuel. Industrial fuel oil may contain as little as 0.3–1% percent sulfur and, in some cases, up to 5% percent sulfur, although there may be price differentials between the lower and higher sulfur content oil supplies.

Diesel engines are using the compression ignition cycle can be fuel flexible and can use fuels such as diesel oil, heavy fuel oil, gaseous fuels (such as natural gas, ignited by a “pilot” injection of diesel oil), crude oil, biofuels liquids (such as palm oil, etc.), and emulsified fuels (such as Orimulsion, etc.). Spark ignition engines can operate (without pilot fuel for ignition) on landfill gas; biogas (from anaerobic digestion), syngas (from gasifiers), and pyrolysis gas or pyrolysis oil can also be used in specific applications. Typical electrical efficiencies in single mode are typically ranging of engine/set range from 40–50% percent for the medium speed engines up to about 50% percent for large low-speed engines and even (gross, LHV basis). Higher efficiencies may be achieved in combined cycle mode. Total efficiency, where heat that would otherwise be lost to the environment is used to produce steam to drive a steam turbine generator, 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 mode, where heat from the application engine is used for an industrial process or for space or water heating, efficiency can be very high depending on the way that the heat is used; efficiencies above 90 percent can be achieved.

If the fuel timing is too early, the cylinder pressure will increase, resulting in higher nitrogen oxide formation. If injection is timed too late, fuel consumption and turbocharger speed will increase. NOx emissions can be reduced by later injection timing, but then particulate matter and the amount of unburned species will increase.
Spark Ignition Lean Burn Gas Engines

76. 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 are typically 0.5 to 1.3 in CHP applications, dependent on the application.

Spark Ignition (SG)

77. 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 prechamber 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.

101. Most industrial gas-fueled spark ignition engines operate on a “lean burn” cycle where the amount of combustion air in the cylinders is very much in excess of the minimum required for complete combustion. This has the impact of reducing the combustion temperature which has a significant impact on reducing NOx production. Increasing the amount of air in the cylinders can lead to difficulties with the initiation of ignition and obtaining stable combustion, and most modern spark ignition engines utilize some sort of pre-combustion chamber in which the air/fuel mixture is less turbulent and often richer in fuel. The fuel in the pre-chamber is more easily ignited and it in turn is used to ignite the lean mixture in the main combustion chamber.

Dual Fuel Engines (DF)

78. 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.

102. In the context of reciprocating engines, Dual Fuel refers to engines which are run predominantly on gaseous fuels ignited by a small (5-10 percent) “pilot” injection of diesel or another suitable liquid fuel. The pilot fuel is ignited by the heat of compression of the combustion air and this engine is therefore a compression-ignition or diesel
engine. This type of engine can also run on up to 100 percent liquid fuel (and is often started up on 100 percent liquid fuel) but cannot operate on gaseous fuel alone. (Note: the term “dual fuel” in the context of combustion turbines has a different meaning, in that it indicates a turbine which can be operated on a gaseous or a liquid fuel).

Treatment of Emissions from Reciprocating Engines

103. NOx emissions from lean burn gas reciprocating engines and liquid fuel diesel engines are generally difficult to reduce further by engine design. Post-treatment using selective catalytic reduction (SCR) may therefore be employed. Emissions of SOx result entirely from the sulfur content of the fuel and cannot be reduced by engine design. Post-treatment in the form of small-scale desulfurization equipment may therefore be employed if a low-sulfur fuel is not available.

Comparison of Reciprocating Engine and Combustion Turbine NOx Emissions

104. The vast majority of NOx produced in combustion turbines and reciprocating engines is a result of the high temperature combustion of fuel. In combustion turbines, there is considerable scope to manage this combustion process by using large combustors in which the fuel to air ratio, the degree of fuel/air mixing, the flame temperature and the duration of combustion can be controlled effectively; and if required water or steam can be introduced to further reduce NOx production. In reciprocating engines, the volume, shape and pressure inside the combustion chamber are constantly changing and the time available for optimal combustion, without heavily compromising efficiency, is inherently very short. Hence the scope for managing the combustion process is much more limited than it is in combustion turbines. It is unlikely that reciprocating engines, constrained by the inherent features of their design, will ever be able to match the NOx emissions from advanced combustion turbines.

Combustion Turbines

79-105. 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. Efficiencies are typically higher than for a steam turbine plant of comparable capacity, though generally lower than for internal combustion plant. Higher temperatures, however, typically lead to increases in NOx emissions. Almost all gas turbines systems are now designed to limit the emissions of NOx, either by the use of steam or water injection (which controls the peak combustion temperature), or by the use of specially designed Dry Low NOx Combustion Systems. Exhaust gases are emitted to the atmosphere from the turbine. Unlike a steam turbine system, gas turbine systems do not have boilers or typically required but, if necessary, may comprise selective catalytic reduction (SCR) which uses a steam supply, condensers, or a waste heat disposal...
Therefore, capital costs are much lower for a gas turbine system than for a steam system or ammonia reagent.

Modern gas turbines can burn a range of gaseous and liquid fuels, although due to the high combustion temperatures and special coatings and materials used in the turbines, there are significant restrictions in the presence of certain contaminants. Although natural gas is the main gaseous fuel, turbines can burn a range of alternative fuels such as gasified LNG, syngas from industrial processes, and hydrogen rich fuels, for example from a pre-combustion CO₂ capture system. The ability to burn alternative fuels is very much dependent on the detailed design of individual turbines and has to be investigated on a case by case basis.

Both pre-combustion and post combustion CO₂ capture systems have been proposed for gas turbine installations, but these have yet to be demonstrated at an industrial scale.

Unlike a steam turbine system, simple cycle gas turbine systems do not have boilers or a steam supply, condensers, or need for a waste heat disposal system. Therefore, capital costs are much lower for a gas turbine system than for a steam system. High temperature heat recovery for CHP applications can be obtained by fitting a waste heat recovery steam generator (HRSG) to the exhaust, without any significant effect on the power output.

In electrical power applications, simple cycle gas turbines are often used for peaking duty, where rapid startup and short runs are needed. Most installed simple gas turbines typically have only a 20–to 30- to 40 percent efficiency, although some smaller units can have efficiencies below 30 percent (net, LHV).

Combined Cycle

Combined-cycle generation is generally 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, with the latest large heavy duty gas turbine systems exceeding 60 percent (net, LHV). Combined-cycle systems may have multiple gas turbines driving one steam turbine or may be of single shaft design. 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 gasification - Combined Heat and Power (CHP)

Cogeneration, or Combined Heat and Power (CHP), is the production of both electrical power and useful thermal output in single fuel conversion process. The thermal output may be used for producing industrial heat or steam and/or municipal heating and/or cooling (via heat-driven absorption chillers). Cogeneration is a more efficient
way of using energy inputs compared to power-only systems. For steam turbine-based power plants (including in combined cycles) it involves some reduction in power output in exchange for a larger amount of heat at a useful temperature. In simple-cycle combustion turbines and internal combustion engines high temperature heat that would otherwise be wasted is available without significant penalty from the exhaust gases. Heat recovered from the cooling circuits can also be used in some applications as an alternative to sending it to cooling towers. Cogeneration technologies are applied based on the trade-off of electrical and thermal values (for steam turbines) and capital and operating costs of heat recovery and distribution compared to the increased total value of the plant outputs.

Integrated Technologies

82-112. Integrated coal gasification combined-cycle (IGCC) units are emerging technologies that can be considered in particular circumstances. In an IGCC system, coal is gasified to produce coal gas, which 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. Combustion of coal gas achieves lower emissions of NOx, SOx, PM and trace contaminants (e.g., mercury than the combustion of coal. The most likely application for IGCC would be in association with pre-combustion capture for CCS systems.

Cogeneration

83. 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 A.1
Generalized Flow Diagram of a Thermal power plant and Associated Operations

87 A number of IGCC plants are in commercial operation across the world, including in the United States, Europe, China and Japan. Examples include Wabash River Coal Gasification Repowering Project (the first full-size commercial IGCC plant in the US, which commenced operation in 1995 and generates 262MW), the ELCOGAS IGCC Plant in Spain (one of the largest commercial IGCC projects in the world with a generating capacity of 330MW) and the Nakoso IGCC demonstration plant in Japan (which came online in 2007 and, since completion of the demonstration project in 2013, has been operated commercially producing 250MWe). Smaller demonstration plants have been successfully developed in other countries, such as the 6.2MW Bharat Heavy Electricals Limited (BHEL) facility in Tamil Nadu, India. Large-scale IGCC plants are under development in a number of countries including Korea, Saudi Arabia, India, Pakistan and the UK. The United States Department of Energy (DOE) maintains a database of example gasification projects worldwide, including IGCC (US DOE / NETL, 2015).

88 Gasification is a thermo-chemical process involving exposing coal in a ‘gasifier’ to steam and carefully controlled amounts of air or oxygen under high temperatures and pressures.

89 Gasification is a process in which coal is introduced to a reducing atmosphere with oxygen or air and steam.

90 Applicable to boiler plant with cooling tower only. Diagram does not apply to engines and turbines which have completely different configurations.
113. With more complex technologies, internal “integration” of thermal processes will become more common. Examples include IGCC, and also the heat integration required to improve efficiency of some CCS technologies. However, these do not involve production of a net external thermal supply, and so are not classed as cogeneration for these purposes. Integrated solar combined cycle (ISCC) units are emerging technologies that involve using thermal solar power to drive a steam cycle, resulting in reduced fossil fuel use per unit of energy generated.
### Annex B: Environmental Assessment Guidance for Thermal Power Projects

84.114. The development of an environmental assessment (EA) for a thermal power project should take into account any government energy and/or environmental policy or strategy including strategic aspects such as energy efficiency improvements in existing power generation, transmission, and distribution systems, demand side management, project siting, fuel choice, technology choice, and environmental performance. Environmental and social considerations should be taken into account at various points in the development of a thermal power plant and ideally early on in the process.

### New Facilities and Expansion of Existing Facilities

85.115. An (EA) for new facilities and a combined EA and environmental audit for existing facilities should be carried out early in the project cycle in order to establish site-specific emissions requirements and other measures for a new or expanded thermal power plant. Table B-1 provides suggested key elements of the EA, the scope of which will depend on project-specific circumstances.

<table>
<thead>
<tr>
<th>Table B-1 Suggested Key EHS Elements for EA of New Thermal Power Project</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Analysis of Alternatives</strong></td>
</tr>
<tr>
<td>• Fuel selection including non-fossil fuel options (coal, oil, gas, biomass, other renewable options – wind, solar, geothermal, hydro), fuel supply sources</td>
</tr>
<tr>
<td>• Power generation technology</td>
</tr>
<tr>
<td>o Thermal generating efficiency (HHV-gross, LHV-gross, HHV-net, LHV-net)</td>
</tr>
<tr>
<td>o Cost</td>
</tr>
<tr>
<td>o CO₂ emissions performance (gCO₂/kWh)</td>
</tr>
<tr>
<td>• GHG emissions reduction / offset options</td>
</tr>
<tr>
<td>o Energy conversion efficiency</td>
</tr>
<tr>
<td>o Offset arrangement</td>
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<tr>
<td>o Use of renewable or low carbon energy sources...etc.</td>
</tr>
<tr>
<td>o Consideration of carbon capture readiness (CCR), where practical</td>
</tr>
<tr>
<td>o Reduction of fugitive emissions and flaring</td>
</tr>
<tr>
<td>• Baseline water quality of receiving water bodies</td>
</tr>
<tr>
<td>• Water supply</td>
</tr>
<tr>
<td>o Surface water, underground water, desalination</td>
</tr>
<tr>
<td>• Cooling system</td>
</tr>
<tr>
<td>o Once-through, wet closed circuit, dry closed circuit</td>
</tr>
<tr>
<td>• Ash disposal system - wet disposal vs. dry disposal</td>
</tr>
<tr>
<td>• Pollution control</td>
</tr>
<tr>
<td>o Air emission – primary vs. secondary flue gas treatment (cost, performance)</td>
</tr>
<tr>
<td>o Effluent (cost, performance)</td>
</tr>
<tr>
<td>• Effluent discharge</td>
</tr>
<tr>
<td>o Surface water</td>
</tr>
<tr>
<td>o Evaporation</td>
</tr>
<tr>
<td>o Recycling – zero discharge</td>
</tr>
<tr>
<td><strong>Siting</strong></td>
</tr>
<tr>
<td>• Siting – consider alternative project locations on the basis of:</td>
</tr>
<tr>
<td>o Land acquisition consideration</td>
</tr>
<tr>
<td>o Access to fuel / electricity grid</td>
</tr>
<tr>
<td>o Existing and future land use zoning</td>
</tr>
<tr>
<td>o Existing and predicted environmental baseline (air, water, noise)</td>
</tr>
</tbody>
</table>
### Impact Assessment
- Estimation of GHG emissions (tCO₂/year, gCO₂/kWh)
- Air quality impact
  - SO₂, NOₓ, PM₁₀, PM₂.₅, Heavy metals as appropriate, Acid deposition if relevant
  - Incremental impacts to the attainment of relevant air quality standards
  - Isothermal concentration lines (short-term, annual average, as appropriate) overlaid with land use and topographic map
  - Cumulative impacts of existing sources / future projects if known
  - Stack height determination
  - Health impact consideration
- Water quality / intake impact
  - Thermal discharge if once-through cooling system is used
  - Other key contaminants as appropriate
  - Water intake impact
- Noise impact
  - Noise contour lines overlaid with land use and locations of receptors
- Determination of pollution prevention and abatement measures

### Mitigation Measures / Management Program
- Air (Stack height, pollution control measures, cost)
- Effluent (wastewater treatment measures, cost)
- Noise (noise control measures, cost)
- Waste utilization / disposal (e.g., ash, FGD by-product, used oil)
  - Ash management plan (quantitative balance of ash generation, disposal, utilization, size of ash disposal site, ash transportation arrangement)
- Fuel supply arrangement
- Emergency preparedness and response plan
- Industrial risk assessment if relevant
### Table B-1 Suggested Key EHS Elements for EA of New Thermal Power Project (cont.)

<table>
<thead>
<tr>
<th>Impact Assessment</th>
<th>Mitigation Measures / Management Program</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Estimation of GHG emissions (tCO&lt;sub&gt;2&lt;/sub&gt;/year, gCO&lt;sub&gt;2&lt;/sub&gt;/kWh)</td>
<td>• Air (Stack height, pollution control measures, cost)</td>
</tr>
<tr>
<td>• Air quality impact</td>
<td>• GHG emissions (Carbon capture and storage, CCS)</td>
</tr>
<tr>
<td>o SO&lt;sub&gt;2&lt;/sub&gt;, NO&lt;sub&gt;2&lt;/sub&gt;, PM&lt;sub&gt;10&lt;/sub&gt;, PM&lt;sub&gt;2.5&lt;/sub&gt;, Heavy metals as appropriate, Acid deposition if relevant</td>
<td>• Effluent (wastewater treatment measures, cost)</td>
</tr>
<tr>
<td>o Incremental impacts to the attainment of relevant air quality standards</td>
<td>• Noise (noise control measures, cost)</td>
</tr>
<tr>
<td>o Isopleth concentration lines (short-term, annual average, as appropriate)</td>
<td>• Waste utilization / disposal (e.g., ash, FGD by-product, used oil)</td>
</tr>
<tr>
<td>o overlaid with land use and topographic map</td>
<td>o Ash management plan (quantitative balance of ash generation, disposal, utilization, size of ash disposal site, ash transportation arrangement)</td>
</tr>
<tr>
<td>o Cumulative impacts of existing sources/ future projects if known</td>
<td>• Fuel supply arrangement</td>
</tr>
<tr>
<td>o Stack height determination</td>
<td>• Emergency preparedness and response plan</td>
</tr>
<tr>
<td>o Visible plume assessment, where relevant</td>
<td>• Industrial risk assessment if relevant</td>
</tr>
<tr>
<td>• Health impact consideration</td>
<td></td>
</tr>
<tr>
<td>o Emissions to air, including health consequences of air pollution</td>
<td>• Water quality / intake impact</td>
</tr>
<tr>
<td>o Noise impacts, on local communities</td>
<td>o thermal discharge if once-through cooling system is used</td>
</tr>
<tr>
<td>o Socio-economic impacts, including employment, access to health and education services</td>
<td>o other key contaminants as appropriate</td>
</tr>
<tr>
<td>o Consideration of different population groups, including different ages and vulnerable groups</td>
<td>o water intake impact</td>
</tr>
<tr>
<td>• Noise impact</td>
<td>• Noise impact</td>
</tr>
<tr>
<td>o Noise contour lines overlaid with land use and locations of receptors</td>
<td>o Noise contour lines overlaid with land use and locations of receptors</td>
</tr>
<tr>
<td>• Determination of pollution prevention and abatement measures</td>
<td></td>
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</tbody>
</table>

**Monitoring Program**

<table>
<thead>
<tr>
<th>Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sampling Frequency</td>
</tr>
<tr>
<td>Evaluation Criteria</td>
</tr>
<tr>
<td>Sampling points overlaid with relevant site layout / surrounding maps</td>
</tr>
<tr>
<td>Cost</td>
</tr>
</tbody>
</table>

86. Tasks related to carrying out the quality impact analysis for the EA should include:

- Collection of baseline data ranging from relatively simple qualitative information (for smaller projects) to more comprehensive quantitative data (for larger projects) on ambient concentrations of parameters and averaging time consistent with relevant host country air quality standards (e.g., parameters such as PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub> (for oil and coal-fired plants), NO<sub>X</sub>, and ground-level ozone; and averaging time such as 1-hour maximum, 24-hour maximum, annual average), within a defined airshed encompassing the proposed project.\textsuperscript{44}

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\textsuperscript{44} The term “airshed” refers to the local area around the plant whose ambient air quality is directly affected by emissions from the plant. The size of the relevant local airshed will depend on plant characteristics, such as stack height, as well as on local meteorological conditions and topography. In some cases, airsheds are defined in legislation or by the relevant environmental authorities. If not, the EA should clearly define the airshed on the basis of consultations with those responsible for local environmental management.
- Evaluation of the baseline airshed quality (e.g., degraded or non-degraded);
- Evaluation of baseline water quality, where relevant;
- Use of appropriate mathematical or physical air quality dispersion models to estimate the impact of the project on the ambient concentrations of these pollutants;
- If acid deposition is considered a potentially significant impact, use of appropriate air quality models to evaluate long-range and trans-boundary acid deposition;
- The scope of baseline data collection and air quality impact assessment will depend on the project circumstances (e.g., project size, amount of air emissions and the potential impacts on the airshed). Examples of suggested practices are presented in Table B-2.

<table>
<thead>
<tr>
<th>Baseline air quality collection</th>
<th>Qualitative information (for small projects e.g., &lt; 100MWth)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Seasonal manual sampling (for mid-sized projects e.g., &lt; 1,200MWth)</td>
</tr>
<tr>
<td></td>
<td>Continuous automatic sampling (for large projects e.g., &gt;= 1,200MWth)</td>
</tr>
<tr>
<td></td>
<td>Modeling existing sources</td>
</tr>
</tbody>
</table>

| Baseline meteorological data collection | Continuous one year data for dispersion modeling from nearby existing meteorological station (e.g., airport, meteorological station) or site-specific station, if installed, for mid-sized and large projects |

<table>
<thead>
<tr>
<th>Evaluation of airshed quality</th>
<th>Determining if the airshed is degraded (i.e., ambient air quality standards are not attained) or non-degraded (i.e., ambient air quality standards are attained)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Assess incremental and resultant levels by screening models (for small projects)</td>
</tr>
<tr>
<td></td>
<td>Assess incremental and resultant levels by refined models (for mid-sized and large projects, or for small projects if determined necessary after using screening models)</td>
</tr>
</tbody>
</table>

Modify emission levels, if needed, to ensure that incremental impacts are small (e.g., 25% of relevant ambient air quality standards) and that the airshed will not become degraded. A visible plume assessment typically involves modelling using a complex model such as ADMS to predict the occurrence and likely length of visible plumes throughout the year. Impacts are considered in the context of the presence and location of sensitive receptors with respect to the plume and whether the plume would extend beyond the site boundary. Model results can also support a landscape and visual effects assessment using photo-montages. A visible plume assessment will typically only be required in situations where the plant is considered likely to produce a visible plume and where the surrounding area is particularly sensitive. Plants considered more likely to produce visible plumes are those using fuels with a high moisture content, such as biomass plants, and those using ‘wet scrubbing’ technologies to reduce pollutant emissions.

Health impact assessment (HIA) typically builds on the findings of environmental and social studies to quantitatively or qualitatively describe the health consequences of identified environmental/social impacts. For example, if a worsening or improvement in air quality is identified in the air quality assessment, an HIA would assess the implications of this on the health of affected communities; this may consider additional information such as existing mortality rates or hospital admissions for respiratory diseases. For further information on health impact assessment approaches, see for example World Health Organization (WHO), IAIA (2006), IFC (2009) and the Institute of Operational Medicine Centre for Health Impact Assessment (IOM—CHIA).

87. When there is a reasonable likelihood that in the medium or long term the power plant will be expanded or other pollution sources will increase significantly, the analysis should take account of the impact of the proposed plant design both immediately and after any formally planned expansion in capacity or in other sources of pollution. Plant design should allow for future installation of additional pollution control equipment, should this prove desirable or necessary based upon predicted air quality impacts and/or anticipated changes in emission standards (i.e.,...

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*For further guidance on refined/screening models, see Appendix W to Part 51 – Guidelines on Air Quality Models by US EPA (Final Rule, November 9, 2005)*
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impending membership into the EU). The EA should also address other project-specific environmental concerns, such as fuel and emissions from fuel impurities. In cases where fuel impurities lead to known hazardous emissions, the EA should estimate the emission amount, assess impacts and propose mitigations to reduce emissions. Examples of compounds which may be present in certain types of coal, heavy fuel oil, petroleum coke, etc. include cadmium, mercury, and other heavy metals.

Rehabilitation of Existing Facilities

116. An environmental assessment of rehabilitation of an existing power plant may be for reasons of component age; change in fuel; need to meet stricter environmental limits; change in configuration; or some combination of these factors. Refurbishment of equipment may be expected to incorporate the latest efficiency improvements, where compatible with retained existing components (e.g., in terms of temperatures and pressures). Net greenhouse gas emissions from an existing plant can be reduced by switching fuels, most notably to bio-based co-firing; however, if 100 percent bio-based firing is contemplated then the plant should be treated in these Guidelines in the same way as for a completely new build.

117. More minor changes to improve environmental performance would include fitting of low-NOx burners; and injection of urea or ammonia (for either SNCR or SCR) for NOx control; addition of post-combustion alkaline reagent injection (dry; semi-dry; or wet FGD) for SO2 and HCl control; injection of activated carbon to capture heavy metals and dioxins/furans; and improvement of particulate control measures by adding cyclones and fabric filters. Turbine steam extractions or other heat recovery methods could also be added in order to serve newly connected thermal loads ( cogeneration).

88. An EA of the proposed rehabilitation should be carried out early in the process of preparing the project in order to allow an opportunity to evaluate alternative rehabilitation options before key design decisions are finalized. The assessment should include an environmental audit that examines the impacts of the existing plant’s operations on nearby populations and ecosystems, supplemented by an EA that examines the changes in these impacts that would result under alternative specifications for the rehabilitation, and the estimated capital and operating costs associated with each option. Depending on the scale and nature of the rehabilitation, the audit/environmental assessment may be relatively narrow in scope, focusing on only a small number of specific concerns that would be affected by the project, or it may be as extensive as would be appropriate for the construction of a new unit at the same site. Normally, it should cover the following points:

- Ambient environmental quality in the airshed or water basin affected by the plant, together with approximate

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Several U.S. states have adopted regulations that give coal-fired power plants the option to meet either a mercury emissions standard based on electricity output or a control-based standard. For instance, Illinois requires all coal-fired power plants of 25 MW electrical capacity or greater to meet either an emissions standard of 0.0080 lbs mercury per gigawatt hour (GWh) gross electrical output or an emissions control requirement of 90 percent relative to mercury input.
estimates of the contribution of the plant to total emissions loads of the main pollutants of concern.

- The impact of the plant, under existing operating conditions and under alternative scenarios for rehabilitation, on ambient air and water quality affecting neighboring populations and sensitive ecosystems.
- The likely costs of achieving alternative emissions standards or other environmental targets for the plant as a whole or for specific aspects of its operations.
- Recommendations concerning a range of cost effective measures for improving the environmental performance of the plant within the framework of the rehabilitation project and any associated emissions standards or other requirements implied by the adoption of specific measures.

These issues should be covered at a level of detail appropriate to the nature and scale of the proposed project. If the plant is located in an airshed or water basin that is polluted as a result of emissions from a range of sources, including the plant itself, comparisons should be made of the relative costs of improving ambient air or water quality by reducing emissions from the plant or by reducing emissions from other sources.