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# Overview

This chapter describes the methods and data needed to estimate emissions from NFR Sector 1.A.1 Energy industries. The activity covers combustion and conversion of fuels to produce energy, for example electricity or heat from point sources:

* 1.A.1.a — Public electricity and heat production
* 1.A.1.b — Petroleum refining
* 1.A.1.c — Manufacture of solid fuels

The information provided in this chapter is also appropriate for assessing stationary combustion emissions within other NFR categories (for example industrial combustion — 1.A.2). Smaller scale combustion (generally < 50 MWth) is considered in Chapter 1.A.4.

Emissions arising from storage and transport of fuels, combustion residues, abatement feedstock and abatement residues are not included; these are in the fugitive emission NFR code 1.B. Guidance for estimating emissions from waste combustion processes is not included here (see the separate chapters concerning waste combustion — 6.C.a, 6.C.b, 6.C.c, and 6.C.e). However, if there is heat recovery or power generation in the incineration process, the emission should be reported under the appropriate 1.A.1 activity.

The range of activities relevant to Chapter 1.A is summarised in Section 2 below, information on sectors which include combustion activities is provided in Appendix A.

The most important pollutants emitted to the atmosphere from the activities are summarised in Table 1‑1.

Table 1‑1 Pollutants with potential for 1.A.1 combustion activities to be a key category

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Source releases** | **Substance** | | | | | | | | | | | | | | |
| Activity | PM (Total suspended particulates (TSP)) | PM10 | PM2.5 | Oxides of sulphur | Oxides of nitrogen | Oxides of carbon | Hydrogen chloride, fluoride | Volatile organic compounds | Metals (excluding mercury and cadmium) and their compounds | Mercury, Cadmium | PAH | Dioxins, PCB, HCB | Ammonia | Hydrogen sulphide | Black Carbon |
| Boilers and furnaces | X | X | X | X | X | X | X | X | X | X | X | X |  |  | X |
| Gas turbine | X | X | X | X | X | X |  | X |  |  |  |  |  |  | X |
| CI engine | X | X | X | X | X | X | X | X | X |  | X |  |  |  | X |
| Refinery activities | X | X | X | X | X | X | X | X | X |  | X |  | X | X | X |
| Coke ovens | X | X | X | X | X | X | X | X | X | X | X |  | X | X | X |

# Description of sources

## 1.A.1.a Public electricity and heat production

This activity covers emissions from combustion plant as point sources. In general, this activity addresses emission from larger combustion appliance (> 50 MWth). Within the European Union, different criteria are applied for the reporting of emissions from combustion plants according to the Industrial Emissions Directive - IED - 2010/75/EC) [EC-IED, 2010].

The emissions considered in this activity are released by a controlled combustion process (boiler emissions, furnace emissions, emissions from gas turbines or stationary engines) and are mainly characterised by the types of fuels used. Furthermore, a characterisation of the combustion sources may be developed according to the size and type of plants as well as from primary or secondary reduction measures. For example, solid, liquid or gaseous fuels are used and there are a range of emission abatement measures (for example PM, SO2 and NOx control).

Emissions from autoproducers (public or private undertakings that generate electricity/heat wholly or partly for their own use, as an activity that supports their primary activity) should be assigned to the sector where they were generated and not under 1.A.1.a.

With the complexity of plant activities and inter-relationships, there may not always be a clear separation between autoproducers and main activity producers. The most important issue is that all facilities be accounted under the most appropriate category and in a complete and consistent manner. For more information on autoproducers, please refer to IPCC 2006 Guidelines [IPCC, 2006]: [www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm](http://www.epa.gov/ttn/emc/methods/method19.html) .

A number of process schemes can be applied for the activities depending on the specific application, typical process schemes are provided in Figure 2‑1, Figure 2‑2 and Figure 2‑3.

Figure 2‑1 Process scheme for heat plant, adapted from IPCC Figure 2.2 in the energy industries chapter



Figure 2‑2 Process scheme for power plant, adapted from IPCC Figure 2.2 in the energy industries chapter



Figure 2‑3 Process scheme for combined power and heat plant, adapted from IPCC Figure 2.2 in the energy industries chapter



## 1.A.1.b Petroleum refining

This activity covers emissions released from production and combustion processes within a refinery. Combustion processes include the heating of crude and petroleum products without contact between flame and products. Combustion activities are generally similar to the activities described in 1.A.1.a, but include fuels such as refinery gas. Production processes such as thermal cracking and catalyst regenerator units as well as venting, flaring and fugitive emissions are covered in Chapters relating to 1.B.2.

Figure 2‑4 Process scheme for petroleum refinery, adapted from IPCC Figure 2.3 in the energy industries chapter



## 1.A.1.c Manufacture of solid fuel and other energy industries

Note that extraction of coal and initial treatment is covered in Chapter 1.B. Under 1.A.1.c the activity covers coke production and emissions associated with combustion in the coke oven. Fugitive emissions from (for example) extinction (quenching) and door leakage is covered in Chapter 1.B. Most coke production is associated with iron and steel production.

Figure 2‑5 Process scheme for coke ovens, adapted from IPCC Figure 2.3 in the energy industries chapter



# 1.A.1.a Public electricity and heat production

## Techniques

Details of technologies used in this activity for combustion of solid, liquid and gaseous fuels can be found within the Best Available Techniques Reference Note (BREF) for energy installations [European Integrated Pollution Prevention and Control Bureau (EIPPCB), 2015] and the US Environmental Protection Agency (USEPA) emission factor handbook (USEPA, AP-42). In general, the size of an installation under this NFR category will exceed 50 MWth; guidance on estimating emissions from smaller appliances can be found within Chapter 1.A.4.

Some general details on technologies are provided here but despite the comparatively small number of installations, there is a wide range of fuel types, combustion technologies and abatement technologies in use.

### Combustion of coal and other solid mineral fuels

Coal is largely burnt as a pulverised fuel with corner (tangential), wall or downfired furnaces. The dry bottom boiler (DBB) has typical combustion temperatures of 900 up to 1 200 °C leading to dry ash discharge from the combustion chamber due to combustion temperatures from. This type of boiler is mainly used for the combustion of hard coal and brown coal/lignite and is applied all over Europe.

The wet bottom boiler (WBB) has typical combustion temperatures exceeding 1 400 °C which leads to a liquid slag discharge from the combustion chamber. This type of boiler is used for hard coal with a low content of volatiles and is mainly applied in Germany.

In fluidised bed combustion (FBC), the combustion of fuel takes place by injection of combustion air through the bottom of the boiler into a turbulent bed. The typical relatively low emissions are achieved by air staging, limestone addition and low combustion temperatures of about 750–950 °C. FBC is in particular adapted to coals rich in ash. Only few large combustion plants are equipped with the FBC technique; in the category of thermal capacities 300 MW mostly circulating fluidised bed combustion (CFBC) is installed. Other types of furnace include grate firing (GF) technologies, but these tend to be comparatively small units.

### Combustion of biomass

The combustion of biomass (straw, wood, landfill gas, etc.) is increasingly relevant for countries to meet the drive for renewable or sustainable energy sources. Co-firing is undertaken with other fuels in many types of combustion plant, but plants burning only biomass tend to use FBC (mostly CFBC) and grate-firing (GF) technologies.

### Combustion of peat

The combustion of peat is relevant for several countries and is generally undertaken using milled peat in FBC in modern facilities, but other technologies do exist.

### Combustion of gas and oil

##### Boilers and furnaces

The technologies in use range from comparatively small package firetube boilers (capacities up to about 20 MWth) to large water tube boilers of up to about 2 000 MWth capacity.

##### Gas turbines

Gas turbines are installed with a thermal capacity ranging from several hundred kW up to about 1 000 MWth. Gaseous fuels are mainly used, such as natural gas or in some instances, process gases or gasification products. Liquid fuels are used, such as light distillates (e.g. naphtha, kerosene or gas oil) but, in general, use of liquid fuels is limited to specific applications or as a standby fuel.

Gas turbines are aero-derivative designs (i.e. based on multiple shaft engines derived from aircraft engine types) or industrial heavy-duty gas turbines (based on single shaft designs). Gas turbines for electricity generation can be open (simple) cycle units but are often installed as a part of a combined cycle gas turbine (CCGT). In a CCGT installation, a heat recovery steam generator (HRSG) is used to recover waste heat from the combustion gases providing steam to power a steam turbine which drives an alternator providing more electricity. The net rated efficiency of a modern CCGT is in excess of 50 %.

Gas turbines are often found in co-generation plant, the gas turbine directly coupled to an electricity generator and the energy from hot exhaust gases recovered in a suitable HRSG (boiler) or used directly (for example drying). Supplementary burners are commonly used to provide additional heat input to the exhaust gases.

Integrated coal gasification combined cycle gas turbine (IGCC) plants use fuel gas derived from coal. Note that for IGCC plants, the only emission relevant unit considered here is the gas turbine.

##### Stationary engines

Stationary engines are spark-ignition engines and compression-ignition engines (2- and 4-stroke) with electrical outputs ranging from less than 100 kW to over 20 MW. Both types represent relevant emission sources. Such units are common as island generators (away from a supply grid), small combined heat and power CHP units, or for cogeneration and standby or emergency uses.

## Emissions

The contributions of point source emissions released by combustion plants to the total emissions reported by countries to the Convention on Long-Range Transboundary Air Pollution (CLRTAP) can be found in the emission databases hosted by the EMEP Centre on Emission Inventories and projections ([[1]](#footnote-1))

The main pollutants are described below with further details provided (from the previous Guidebook chapter) in Appendix B.

Note that the inventory methodologies for Greenhouse gas emissions (carbon dioxide, methane and nitrous oxide) are not included – refer to IPCC guidance [IPCC, 2006].

##### Sulphur oxides

In the absence of flue gas desulphurisation (FGD) technology, the emissions of sulphur oxides (SOx) are directly related to the sulphur content of the fuel. The sulphur content of refined natural gas is negligible. The majority of SOx is sulphur dioxide (SO2) although small proportions of sulphur trioxide (SO3) can arise.

##### Nitrogen oxides

Emissions of nitrogen oxides (nitric oxide and nitrogen dioxide — NOx) arise from nitrogen in the fuel (mainly relevant to solid and liquid fuels) and from reaction of atmospheric nitrogen. Combustion control can provide a high degree of NOx emission control (low NOx burner technology) and this may be supplemented by use of selective catalytic reduction (SCR) or selective non-catalytic reduction techniques (SNCR).

##### Non-methane volatile organic compounds (NMVOC)

Emissions of non-methane volatile organic compounds (NMVOC), e.g. olefins, ketones, aldehydes, result from incomplete combustion. Furthermore, unreacted fuel compounds such as ethane (C2H6) can be emitted. The relevance of NMVOC and CH4 emissions from boilers, which are often reported together as VOC, is very low for large-sized combustion plants. Usually, VOC emissions are the result of incomplete combustion. In large combustion systems the combustion process is automatically regulated. Therefore, VOC emissions tend to decrease as the plant size increases (Rentz et al, 1993). Gas engines are an exception and can emit relevant NMVOC and CH4emissions.

##### Carbon monoxide (CO)

Carbon monoxide (CO) appears always as an intermediate product of the combustion process and in particular under sub-stoichiometric combustion conditions. However, the relevance of CO released from combustion plants is not very high compared to CO2. The formation mechanisms of CO and VOC are similarly influenced by combustion conditions. Substantial emissions of CO can occur if combustion conditions are poor. Higher CO emission are also possible in the case of flue gas recirculation as a primary measure for NOX reduction.

##### Ammonia (NH3)

Emissions of ammonia (NH3) are not generally associated with a combustion process; emissions can result from incomplete reaction of NH3 additive in NOx abatement systems — selective catalytic and non-catalytic reduction (SCR and SNCR). Higher NH3 emissions can be expected when the SCR system is located downstream from the flue-gas desulphurisation system – and, thus, at the end of the flue-gas cleaning track (Tail-end) and in the case of SNCR. When the SCR system is located between the feed-water preheating system and the air preheating system (High dust), lower NH3 emissions can be expected.

##### Particulate matter

Particulate matter (PM) emissions from large combustion installations (> 50 MW) burning solid fuels are often lower than emissions from smaller plants (per unit of energy input); the physical and chemical characteristics of the PM also differ. This is because different combustion and abatement techniques are applied.

Combustion of fuels can generate solid residues which may be deposited within combustion chambers (furnace bottom ash) within the furnace, boiler surfaces or ducting (fly ash) or on heat exchanger surfaces (soot and fly ash). Coal and other fuels with significant ash content have the highest potential to emit PM. Suspended ash material in exhaust gases may be retained by particulate abatement or other emission abatement equipment (abatement residues). Material which remains in the flue gases beyond the abatement equipment and passes to the atmosphere is primary PM. Secondary PM is formed by chemical and physical processes after discharge to atmosphere and is NOT considered here.

A number of factors influence the measurement and determination of primary PM emissions from activities and, the quantity of PM determined in an emission measurement depends to a large extent on the measurement conditions. This is particularly true of activities involving high temperature and semi-volatile emission components – in such instances the PM emission may be partitioned between a solid/aerosol phase and material which is gaseous at the sampling point but which can condense in the atmosphere. The proportion of filterable and condensable material will vary depending on the temperature of the flue gases and in sampling equipment.

A range of filterable PM measurement methods are applied around the world typically with filter temperatures of 70-160°C (the temperature is set by the test method).  Condensable fractions can be determined directly by recovering condensed material from chilled impinger systems downstream of a filter – note that this is condensation without dilution and can require additional processing to remove sampling artefacts. Another approach for total PM includes dilution where sampled flue or exhaust gases are mixed with ambient air (either using a dilution tunnel or dilution sampling systems) and the filterable and condensable components are collected on a filter at lower temperatures (but depending on the method this can be 15-52°C). The use of dilution methods, however, may be limited due to practical constraints with weight and/or size of the equipment.

The PM emission factors (for TSP, PM10 and PM2.5) can represent the total primary PM emission, or the filterable PM fraction. The basis of the emission factor is described (see individual emission factor tables).

##### Black carbon (BC)

Combustion of fossil fuel and biomass is the main source of black carbon (BC) emission (Diehl et al. 2012). Black carbon is the term for a wide range of carbon containing compounds but is determined by assessment of the *optical* properties of collected particulate matter. It covers large polycyclic species, charred plants to highly graphitized soot. Other commonly used classifications include elemental carbon (EC) and organic carbon (OC), which refer to carbon species that have been classified *chemically*. EC and OC are always co-emitted, but in different proportions dependent upon the fuel properties and the combustion conditions.

Using these classifications, BC and EC (as the more light absorbing / refractory species) are often treated as equal. In reality, there may be small differences in the PM fraction of BC and EC resulting from the different classification techniques used. Black Carbon was selected as the term identified within the Gothenburg Protocol, with the requirement that Parties develop emission inventories and projections for BC, and it is proposed that a similar requirement be included under the new NECD. As such, in this guidebook emission factors are presented as BC.

Literature values of emission factors for BC are often derived by thermal chemical techniques representative of EC. It is therefore important for inventory compilers to understand that the tier 1 BC emission factors presented in this guidance are assumed to be equal to the emission factors for EC, and therefore some uncertainty is introduced. Where possible, appendices of full carbon speciation are provided for key sources. Country-specific (higher tier) methods will be preferable where this is feasible.

The same emission control techniques that limit the emission of PM will also reduce the emission of BC. However, measurement data that address the abatement efficiencies for BC are limited. This means that in general it is assumed that the BC emission can be reduced proportionally to the filterable PM emission and, in particular, PM2.5 emission. Consequently, for inventory development, the BC emission factors are expressed as percentage of the PM2.5 emission. It must be noted that measurement of BC emissions is not a standardised technique and that particle number or surface area may be relevant metrics. However, the approach adopted in the present chapter is to develop a mass inventory based on the PM2.5 inventory.

##### Metals

Most of the heavy metals considered (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn and V) are normally released as compounds (e.g. oxides, chlorides) in association with particulates. Only Hg, As and Se are at least partly present in the vapour phase. The content of heavy metals in coal is normally several orders of magnitude higher than in oil products (except occasionally for Ni and V in heavy fuel oil) . For natural gas emissions of mercury and arsenic are relevant. During the combustion of coal, particles undergo complex changes which lead to vaporisation of volatile elements. The rate of volatilisation of heavy metal compounds depends on fuel characteristics (e.g. concentrations in coal, fraction of inorganic components, such as calcium) and on technology characteristics (e.g. type of boiler, operation mode, abatement technology).

## Controls

Details of relevant abatement technologies for combustion plant are described in the BREF note for large combustion plant ( http://eippcb.jrc.ec.europa.eu/reference/); some further detail on NOx and SO2 emission controls are also provided in Appendix B. Relevant abatement technologies for selected pollutants are outlined below.

### Sulphur oxides

There are in-furnace technologies which incorporate injection of an absorbent material (typically lime) into the furnace. Use of such systems is quite common in FBC where the lime can be added to the bed and high recirculation is possible.

Post combustion flue gas desulphurisation (FGD) processes are more common and are designed to remove SO2 from the flue gas of combustion installations. Most processes, like the wet scrubbing process (WS), the spray dryer absorption (SDA), the dry sorbent injection (DSI) and the Walther process (WAP) are based on the reaction of the SO2 with an alkaline agent added as solid or as suspension/solution of the agent in water to form the respective salts. In secondary reactions SO3, fluorides and chlorides are also removed. In the case of some processes the SO2 is recovered as sulphur or sulphuric acid. Use of FGD processes can also reduce particulate and metal emissions. The most common technologies are described below.

##### Lime/limestone wet scrubbing (WS)

The pollutants are removed from the flue gas by chemical reactions with alkaline slurry (suspension of calcium compounds in water). The main product is gypsum. The WS process represents the main technology used by FGD-equipped electrical capacity installed in European Organisation for Economic Co-operation and Development (OECD) countries. Facilities are in operation at combustion units using hard coal, lignite and oil with sulphur contents from about 0.8 to more than 3.0 wt.%. The SO2 reduction efficiency is > 90 %.

##### Spray dryer (semi-dry) absorption (SDA)

The SDA process removes the pollutant components from flue gas of fossil-fired combustion units by injection of Ca(OH)2 slurry. The process forms a dry by-product requiring downstream collection of PM. The SO2 reduction efficiency is > 90 %.

##### Dry sorbent injection (DSI)

The DSI process is based on a gas/solid reaction of the flue gas and a dry sorbent (typically lime, but sodium hydrogen carbonate NaHCO3 is used in some smaller applications).

### Nitrogen oxides

##### Primary measures

Primary measures minimise formation of NOx in the furnace or combustion chamber and include low-NOx burners (LNB), staged air supply, flue gas recirculation, overfire air, reburn, water/steam injection and related technology. These measures can be retrofitted to existing boilers to achieve varying degrees of NOx reduction. Modern gas turbines can achieve very low NOx emissions by application of dry low NOx (DLN) burner technology without secondary measures.

##### Secondary measures — DeNOx processes

The principal abatement measures are selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). The reduction of nitrogen oxides in the flue gas is based on the selective reaction of NOx. The SNCR process involves injection of ammonia or urea near the furnace. Emission reduction with SNCR can be limited (up to 50 %) and is lower than with SCR. An SCR system is based on selective reactions with injected additives in the presence of a catalyst. The additives used are mostly ammonia (gaseous and in solution) but also urea. The NOx reduction efficiency can be between 70 and 90 %.

### Particulate matter

The main technology in use is electrostatic precipitation (EP); however, fabric filters (FF) are also used. Removal of particulate also reduces emissions of most heavy metals as these are mainly in the particulate phase. Both modern EP and FF can represent Best Available Techniques (BAT), but note that EP performance can vary widely between older and modern equipment. FGD can also be an effective PM abatement device; DSI and SDA systems often incorporate FF for sorbent and PM removal, Wet scrubbing systems can also achieve BAT achievable emission levels for PM. Multicyclone devices can be found on smaller, older combustion units or as an initial treatment stage.

## Methods

### Choice of method

Figure 3‑1 presents the procedure to select the methods for estimating process emissions from combustion in energy and transformation industries. The basic concept is:

* if detailed information is available, use it;
* if the source category is a key source, a Tier 2 or better method must be applied and detailed input data must be collected. The decision tree directs the user in such cases to the Tier 2 method, since it is expected that it is easier to obtain the necessary input data for this approach than to collect facility-level data needed for a Tier 3 estimate. However, the inventory compiler should be aware that, because the number of sources may be comparatively small, in many instances the data required for a Tier 3 approach may be only a little more difficult to obtain than at Tier 2;
* detailed process modelling is not explicitly included in this decision tree. However, detailed modelling will usually be done at facility level and results of such modelling could be seen as ‘facility data’ (Tier 3) in the decision tree.

Figure 3‑1 Decision tree for combustion in energy transformation industries



### Tier 1 default approach

#### Algorithm

The Tier 1 approach for process emissions from combustion uses the general equation:

 (1)

*Epollutant* annual emission of pollutant

*EFpollutant* emission factor of pollutant

*ARfuel consumption* activity rate by fuel consumption

This equation is applied at the national level, using annual national total fuel use (disaggregated by fuel type). Information on fuel consumption suitable for estimating emissions using the simpler estimation methodology is widely available from UN statistical yearbooks or national statistics.

The Tier 1 emission factors assume an average or typical technology and abatement implementation.

In cases where specific combustion technology and abatement techniques are to be taken into account, a Tier 1 method is not applicable and a Tier 2 or Tier 3 approach must be used. Some further detail on NOx and SO2 emission controls and abatement efficiency are provided in Appendix B.

#### Default Tier 1 emission factors (EF)

The Tier 1 default emission factors derived from available data and information have been developed for key fuel groups (Table 3‑1) and are given in Table 3‑2 to Table 3‑7.

Table 3‑1 Tier 1 fuel classifications

|  |  |
| --- | --- |
| Tier 1 Fuel type | Associated fuel types |
| Hard coal | Coking coal, other bituminous coal, sub-bituminous coal, coke, manufactured ‘patent’ fuel |
| Brown coal | Lignite, oil shale, manufactured ‘patent’ fuel, peat |
| Natural gas | Natural gas, liquified natural gas |
| Other gaseous fuels | Refinery gas (EFs for refinery gas are available in section 1.A.1.b), gas works gas, coke oven gas, blast furnace gas (EFs for iron and steel gases in 1.A.2), pit gas |
| Heavy fuel oil | Residual fuel oil, refinery feedstock, petroleum coke, orimulsion, bitumen |
| Light oil | Gas oil, kerosene, naphtha, shale oil, liquified petroleum gas |
| Solid biomass | Wood, charcoal, vegetable (agricultural) waste |
| Biogases | Biogas, sewage gas, landfill gas |

**Note:** The associated fuel types indicated in Table 3-2 are based on the emission characteristics and are not to be used for categorising fuels into the main fuel groups (solid, liquid, gaseous, biomass) used for reporting.

The emission factors provided in Table 3‑2 to Table 3‑7 have been derived from available materials, taking into account the results of an assessment of emission factors included in previous versions of the Guidebook and elsewhere, including the newer information from the BREF document on Best Available Techniques in Large Combustion Plants (European Commission, 2006). The emission factors are grouped by major fuel types. In the absence of detail on types and relative use of types of combustion or abatement technology, which will be different for each country, the proposed factors represent a mean for the range of technologies in use with the 95 % figures a measure of the range of emissions in the sector. The factors will represent a very wide range of combustion technologies and emissions; they do not represent BAT or unabated emissions.

Note that NOx emission factors are expressed as NO2 and that PCDD/F emission factors are presented as I-TEQ (NATO) toxic equivalents.

Emission factors for sulphur oxides are provided in the Tier 1 tables, but these assume no SO2 abatement and a defined fuel sulphur content. Where countries have no FGD and have knowledge of fuel sulphur content then it is recommended that a sulphur oxides emission factor is calculated from fuel sulphur content assuming 100 % conversion to SO2 and no retention in ash.

EF SO2  = [S] x 20,000 / CVNet

where:

EF SO2  is the SO2 emission factor (g/GJ)

[S] is sulphur content of the fuel (% w/w)

CVNet is fuel CV (GJ/tonne, net basis)

For emission factors for the combustion of waste, please refer to Chapters 6.C.a, 6.C.b and 6.C.c, depending on the type of waste that is being combusted.

The BC emission factors presented in this Guidance are derived on the basis of EC and it is therefore assumed that BC=EC.

Table 3‑2 Tier 1 emission factors for source category 1.A.1.a using hard coal

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Hard Coal | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 209 | g/GJ | 200 | 350 | US EPA (1998), chapter 1.1 |
| CO | 8.7 | g/GJ | 6.15 | 15 | US EPA (1998), chapter 1.1 |
| NMVOC | 1.0 | g/GJ | 0.6 | 2.4 | US EPA (1998), chapter 1.1 |
| SOx | 820 | g/GJ | 330 | 5000 | See Note |
| TSP | 11.4 | g/GJ | 3 | 300 | US EPA (1998), chapter 1.1 |
| PM10 | 7.7 | g/GJ | 2 | 200 | US EPA (1998), chapter 1.1 |
| PM2.5 | 3.4 | g/GJ | 0.9 | 90 | US EPA (1998), chapter 1.1 |
| BC | 2.2 | % of PM2.5 | 0.27 | 8.08 | See Note |
| Pb | 7.3 | mg/GJ | 5.16 | 12 | US EPA (1998), chapter 1.1 |
| Cd | 0.9 | mg/GJ | 0.627 | 1.46 | US EPA (1998), chapter 1.1 |
| Hg | 1.4 | mg/GJ | 1.02 | 2.38 | US EPA (1998), chapter 1.1 |
| As | 7.1 | mg/GJ | 5.04 | 11.8 | US EPA (1998), chapter 1.1 |
| Cr | 4.5 | mg/GJ | 3.2 | 7.46 | US EPA (1998), chapter 1.1 |
| Cu | 7.8 | mg/GJ | 0.233 | 15.5 | Expert judgement derived from EMEP/EEA (2006) |
| Ni | 4.9 | mg/GJ | 3.44 | 8.03 | US EPA (1998), chapter 1.1 |
| Se | 23 | mg/GJ | 16 | 37.3 | US EPA (1998), chapter 1.1 |
| Zn | 19 | mg/GJ | 7.75 | 155 | Expert judgement derived from EMEP/EEA (2006) |
| PCB | 3.3 | ng WHO-TEG/GJ | 1.1 | 9.9 | Grochowalski & Konieczyński, 2008 |
| PCDD/F | 10 | ng I-TEQ/GJ | 5 | 15 | UNEP (2005); Coal fired power boilers |
| Benzo(a)pyrene | 0.7 | µg/GJ | 0.245 | 2.21 | US EPA (1998), chapter 1.1 |
| Benzo(b)fluoranthene | 37 | µg/GJ | 3.7 | 370 | Wenborn et al., 1999 |
| Benzo(k)fluoranthene | 29 | µg/GJ | 2.9 | 290 | Wenborn et al., 1999 |
| Indeno(1,2,3-cd)pyrene | 1.1 | µg/GJ | 0.591 | 2.36 | US EPA (1998), chapter 1.1 |
| HCB | 6.7 | µg/GJ | 2.2 | 20.1 | Grochowalski & Konieczyński, 2008 |

Notes:

The default tier 1 emission factors are based on the tier 2 emission factors for dry bottom boilers. For conversion of the US EPA data the heating value as provided in the reference has been used (26 MMBTU/ton). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The EFs for benzo(b)fluoranthene and benzo(k)fluoranthene are converted using the average NCV for other bituminous coal of 24.1 GJ/ton from Energy Statistics Manual (OECD/IEA, 2005).

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The BC share is derived as the average of data from Henry & Knapp (1980), Olmez et al. (1988), Watson et al. (2001), Fisher et al. (1979), Griest & Tomkins (1984), Engelbrecht et al. (2002), Chow et al. (2004) and Speciate (US EPA, 2011).

The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions and are based on an ash content of 8.2%. Note that condensable PM emission factors are also provided in US EPA (1998), Chapter 1.1.

Table 3‑3 Tier 1 emission factors for source category 1.A.1.a using brown coal

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Brown Coal | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, PCB, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 247 | g/GJ | 143 | 571 | US EPA (1998), chapter 1.7 |
| CO | 8.7 | g/GJ | 6.72 | 60.5 | US EPA (1998), chapter 1.7 |
| NMVOC | 1.4 | g/GJ | 0.84 | 3.36 | US EPA (1998), chapter 1.7 |
| SOx | 1680 | g/GJ | 330 | 5000 | See Note |
| TSP | 11.7 | g/GJ | 1.2 | 117 | US EPA (1998), chapter 1.7 |
| PM10 | 7.9 | g/GJ | 1 | 79 | US EPA (1998), chapter 1.7 |
| PM2.5 | 3.2 | g/GJ | 1 | 32 | US EPA (1998), chapter 1.7 |
| BC | 1 | % of PM2.5 | 0.1 | 4 | Kupiainen and Klimont, 2007 |
| Pb | 15 | mg/GJ | 10.6 | 24.7 | US EPA (1998), chapter 1.7 |
| Cd | 1.8 | mg/GJ | 1.29 | 3 | US EPA (1998), chapter 1.7 |
| Hg | 2.9 | mg/GJ | 2.09 | 4.88 | US EPA (1998), chapter 1.7 |
| As | 14.3 | mg/GJ | 10.3 | 24.1 | US EPA (1998), chapter 1.7 |
| Cr | 9.1 | mg/GJ | 6.55 | 15.3 | US EPA (1998), chapter 1.7 |
| Cu | 1.0 | mg/GJ | 0.2 | 5 | EMEP/EEA (2006) |
| Ni | 9.7 | mg/GJ | 7.06 | 16.5 | US EPA (1998), chapter 1.7 |
| Se | 45 | mg/GJ | 32.8 | 76.5 | US EPA (1998), chapter 1.7 |
| Zn | 8.8 | mg/GJ | 0.504 | 16.8 | EMEP/EEA (2006) |
| PCBs | 3.3 | ng WHO-TEG/GJ | 1.1 | 9.9 | Grochowalski & Konieczyński, 2008 |
| PCDD/F | 10 | ng I-TEQ/GJ | 5 | 15 | UNEP (2005); Coal fired power boilers |
| Benzo(a)pyrene | 1.3 | µg/GJ | 0.26 | 6.5 | US EPA (1998), chapter 1.7 |
| Benzo(b)fluoranthene | 37 | µg/GJ | 3.7 | 370 | Wenborn et al., 1999 |
| Benzo(k)fluoranthene | 29 | µg/GJ | 2.9 | 290 | Wenborn et al., 1999 |
| Indeno(1,2,3-cd)pyrene | 2.1 | µg/GJ | 0.42 | 10.5 | US EPA (1998), chapter 1.7 |
| HCB | 6.7 | µg/GJ | 2.2 | 20.1 | Grochowalski & Konieczyński, 2008 |

Notes:

The tier 1 default emission factors are based on the tier 2 emission factors for dry/wet bottom boilers.

For conversion of the US EPA data the heating value as provided in the reference has been used (6500 BTU/lb). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU, 2000 lb/ton and 453.59237 g/lb. The EFs for Cu and Zn are converted using the average NCV 11.9 GJ/Mg from IPCC Guidelines (IPCC, 2006).

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions and are based on an ash content of 5%. Note that condensable PM emission factors are also provided in US EPA (1998), Chapter 1.7.

Table 3‑4 Tier 1 emission factors for source category 1.A.1.a using natural gas

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Natural gas | | | | |
| **Not applicable** | BC, PCDD/F, PCBs, HCB, PAH | | | | |
| **Not estimated** | NH3, | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 89 | g/GJ | 15 | 185 | US EPA (1998), chapter 1.4 |
| CO | 39 | g/GJ | 20 | 60 | US EPA (1998), chapter 1.4 |
| NMVOC | 2.6 | g/GJ | 0.65 | 10.4 | US EPA (1998), chapter 1.4 |
| SOx (US region) | 0.281 | g/GJ | 0.169 | 0.393 | US EPA (1998), chapter 1.4 |
| SOx (EU region) | 0,244 | g/GJ | <0.030 | 0.458 | DBI 2014, Fluxys 2009-2011 |
| TSP | <0.14 | g/GJ | <0.09 | <0,19 | UBA 2019 |
| PM10 | <0.14 | g/GJ | <0.09 | <0,19 | Equal to TSP |
| PM2.5 | <0.14 | g/GJ | <0.09 | <0,19 | Equal to TSP |
|  |  |  |  |  |  |
| Pb | <0.0015 | mg/GJ | <0.0005 | <0.0045 | Nielsen et al., 2012 |
| Cd | <0.00025 | mg/GJ | <0.00008 | <0.00075 | Nielsen et al., 2012 |
| Hg | 0.05 | mg/GJ | <0.0014 | 1 | Nielsen et al., 2010, DBI 2014 |
| As | 0.12 | mg/GJ | <0.027 | 0.36 | Nielsen et al., 2012, DBI 2014 |
| Cr | <0.00076 | mg/GJ | <0.00025 | <0.00228 | Nielsen et al., 2012 |
| Cu | <0.000076 | mg/GJ | <0.000025 | <0.000228 | Nielsen et al., 2012 |
| Ni | <0.00051 | mg/GJ | <0.00017 | <0.00153 | Nielsen et al., 2012 |
| Se | <0.0112 | mg/GJ | <0.00375 | <0.0337 | US EPA (1998), chapter 1.4 |
| Zn | <0.0015 | mg/GJ | <0.0005 | <0.0045 | Nielsen et al., 2012 |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |

Notes:

For conversion of the US EPA data the heating value as provided in the reference has been used (1.02 BTU/scf). This has been converted to NCV using a factor of 0.90. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The factor for SOx (for US region) is based on approximately 0.01 gm3 mass sulphur content.

The TSP, PM10 and PM2.5 emission factors, some of the SOx emission factors and most of the heavy metal emission factors are derived from measurement data which were below the limit of quantification.

Table 3-5 Tier 1 emission factors for source category 1.A.1.a using other gaseous fuels (process gases from iron and steel process)

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Blast furnace gas/basic oxygen furnace gas/coke oven gas | | | | |
| **Not applicable** | NH3 | | | | |
| **Not estimated** | PM10, PM2.5, BC, NMVOC, HM, PCDD/F, PCBs, HCB, PAH | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 25 | g/GJ | 22 | 27 | UBA 2019 |
| CO | 5 | g/GJ | 1 | 9 | UBA 2019 |
| SOx | 40 | g/GJ | 36 | 44 | UBA 2019 |
| TSP | 1.5 | g/GJ | 1 | 2 | UBA 2019 |

Table 3‑6 Tier 1 emission factors for source category 1.A.1.a using heavy fuel oil

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Heavy Fuel Oil | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, PCBs, Benzo(a)pyrene, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| Nox | 142 | g/GJ | 70 | 300 | US EPA (2010), chapter 1.3 |
| CO | 15.1 | g/GJ | 9.06 | 21.1 | US EPA (2010), chapter 1.3 |
| NMVOC | 2.3 | g/GJ | 1.4 | 3.2 | US EPA (2010), chapter 1.3 |
| Sox | 495 | g/GJ | 146 | 1700 | See Note |
| TSP | 35.4 | g/GJ | 2 | 200 | US EPA (2010), chapter 1.3 |
| PM10 | 25.2 | g/GJ | 1.5 | 150 | US EPA (2010), chapter 1.3 |
| PM2.5 | 19.3 | g/GJ | 0.9 | 90 | US EPA (2010), chapter 1.3 |
| BC | 5.6 | % of PM2.5 | 0.22 | 8.69 | See Note |
| Pb | 4.56 | mg/GJ | 2.28 | 9.11 | US EPA (2010), chapter 1.3 |
| Cd | 1.2 | mg/GJ | 0.6 | 2.4 | US EPA (2010), chapter 1.3 |
| Hg | 0.341 | mg/GJ | 0.17 | 0.682 | US EPA (2010), chapter 1.3 |
| As | 3.98 | mg/GJ | 1.99 | 7.97 | US EPA (2010), chapter 1.3 |
| Cr | 2.55 | mg/GJ | 1.27 | 5.1 | US EPA (2010), chapter 1.3 |
| Cu | 5.31 | mg/GJ | 2.66 | 10.6 | US EPA (2010), chapter 1.3 |
| Ni | 255 | mg/GJ | 127 | 510 | US EPA (2010), chapter 1.3 |
| Se | 2.06 | mg/GJ | 1.03 | 4.12 | US EPA (2010), chapter 1.3 |
| Zn | 87.8 | mg/GJ | 43.9 | 176 | US EPA (2010), chapter 1.3 |
| PCDD/F | 2.5 | ng I-TEQ/GJ | 1.25 | 3.75 | UNEP (2005); Heavy fuel fired power boilers |
| *Benzo(b)fluoranthene* | *4.5* | *µg/GJ* | *1.5* | *13.5* | *US EPA (2010), chapter 1.3* |
| *Benzo(k)fluoranthene* | *4.5* | *µg/GJ* | *1.5* | *13.5* | *US EPA (2010), chapter 1.3* |
| Indeno(1,2,3-cd)pyrene | 6.92 | µg/GJ | 3.46 | 13.8 | US EPA (2010), chapter 1.3 |

Note:

For conversion of the US EPA data the heating value as provided in the reference has been used (150 MMBTU/103 gal). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The BC emission factor is derived as the average of the data found in Olmez et al. (1988), England et al. (2007) and the Speciate database (US EPA, 2011).

The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions and are based on a sulphur content of 1%. Note that condensable PM emission factors are also provided in US EPA (1998), Chapter 1.3.

Tier 1 emission factors for source category 1.A.1.a using gas oil

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | **Gas oil** | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, PCB, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| Nox | 65 | g/GJ | 22 | 195 | US EPA (1998), chapter 1.3 |
| CO | 16.2 | g/GJ | 4 | 65 | US EPA (1998), chapter 1.3 |
| NMVOC | 0.8 | g/GJ | 0.48 | 1.28 | US EPA (1998), chapter 1.3 |
| Sox | 46.5 | g/GJ | 4.65 | 465 | See Note |
| TSP | 6.5 | g/GJ | 2 | 20 | US EPA (1998), chapter 1.3 |
| PM10 | 3.2 | g/GJ | 1 | 10 | US EPA (1998), chapter 1.3 |
| PM2.5 | 0.8 | g/GJ | 0.3 | 2.5 | US EPA (1998), chapter 1.3 |
| BC | 33.5 | % of PM2.5 | 28.9 | 38 | Hildemann et al., 1981 & Bond et al., 2006 |
| Pb | 4.07 | mg/GJ | 0.41 | 40 | US EPA (1998), chapter 1.3 |
| Cd | 1.36 | mg/GJ | 0.14 | 15 | US EPA (1998), chapter 1.3 |
| Hg | 1.36 | mg/GJ | 0.14 | 15 | US EPA (1998), chapter 1.3 |
| As | 1.81 | mg/GJ | 0.18 | 20 | US EPA (1998), chapter 1.3 |
| Cr | 1.36 | mg/GJ | 0.14 | 15 | US EPA (1998), chapter 1.3 |
| Cu | 2.72 | mg/GJ | 0.27 | 30 | US EPA (1998), chapter 1.3 |
| Ni | 1.36 | mg/GJ | 0.14 | 15 | US EPA (1998), chapter 1.3 |
| Se | 6.79 | mg/GJ | 0.68 | 70 | US EPA (1998), chapter 1.3 |
| Zn | 1.81 | mg/GJ | 0.18 | 20 | US EPA (1998), chapter 1.3 |
| PCDD/F | 0.5 | ng I-TEQ/GJ | 0.25 | 1 | UNEP, 2005 |
| Indeno(1,2,3-cd)pyrene | 6.92 | µg/GJ | 3.46 | 13.8 | US EPA (1998), chapter 1.3 |

Note:

For conversion of the US EPA data the heating value as provided in the reference has been used (140 MMBTU/103 gal). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The factor for SOx assumes no SO2 abatement and is based on 0.1 % mass sulphur content.

The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions. Note that condensable PM emission factors are also provided in US EPA (1998), Chapter 1.3.

Table 3‑6 Tier 1 emission factors for source category 1.A.1.a using solid biomass

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Solid biomass | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 81 | g/GJ | 40 | 160 | Nielsen et al., 2010 |
| CO | 90 | g/GJ | 45 | 180 | Nielsen et al., 2010 |
| NMVOC | 7.31 | g/GJ | 2.44 | 21.9 | US EPA (2003), chapter 1.6 |
| SOx | 10.8 | g/GJ | 6.45 | 15.1 | US EPA (2003), chapter 1.6 |
| TSP | 172 | g/GJ | 86 | 344 | US EPA (2003), chapter 1.6 |
| PM10 | 155 | g/GJ | 77 | 310 | US EPA (2003), chapter 1.6 |
| PM2.5 | 133 | g/GJ | 66 | 266 | US EPA (2003), chapter 1.6 |
| BC | 3.3 | % of PM2.5 | 1.6 | 6.6 | See Note |
| Pb | 20.6 | mg/GJ | 12.4 | 28.9 | US EPA (2003), chapter 1.6 |
| Cd | 1.76 | mg/GJ | 1.06 | 2.47 | US EPA (2003), chapter 1.6 |
| Hg | 1.51 | mg/GJ | 0.903 | 2.11 | US EPA (2003), chapter 1.6 |
| As | 9.46 | mg/GJ | 5.68 | 13.2 | US EPA (2003), chapter 1.6 |
| Cr | 9.03 | mg/GJ | 5.42 | 12.6 | US EPA (2003), chapter 1.6 |
| Cu | 21.1 | mg/GJ | 12.6 | 29.5 | US EPA (2003), chapter 1.6 |
| Ni | 14.2 | mg/GJ | 8.51 | 19.9 | US EPA (2003), chapter 1.6 |
| Se | 1.2 | mg/GJ | 0.722 | 1.69 | US EPA (2003), chapter 1.6 |
| Zn | 181 | mg/GJ | 108 | 253 | US EPA (2003), chapter 1.6 |
| PCB | 3.5 | µg/GJ | 0.35 | 35 | US EPA (2003), chapter 1.6 |
| PCDD/F | 50 | ng I-TEQ/GJ | 25 | 75 | UNEP (2005) (for clean wood) |
| Benzo(a)pyrene | 1.12 | mg/GJ | 0.671 | 1.57 | US EPA (2003), chapter 1.6 |
| Benzo(b)fluoranthene | 0.043 | mg/GJ | 0.0215 | 0.0645 | US EPA (2003), chapter 1.6 |
| Benzo(k)fluoranthene | 0.0155 | mg/GJ | 0.00774 | 0.0232 | US EPA (2003), chapter 1.6 |
| Indeno(1,2,3-cd)pyrene | 0.0374 | mg/GJ | 0.0187 | 0.0561 | US EPA (2003), chapter 1.6 |
| HCB | 5 | µg/GJ | 0.5 | 50 | Bailey, 2001 |

Note: For conversion of the US EPA data units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The BC emission factor is an average of the data in Dayton & Bursey (2001) and the Speciate database (US EPA, 2011).

The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions. Note that a condensable PM emission factor is also provided in US EPA (1998), Chapter 1.6.

Table 3-7 Tier 1 emission factors for source category 1.A.1.a using biogas

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Biogas | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | TSP, PM10, PM2.5 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 198 | g/GJ | 28 | 582 | DBFZ 2011 |
| CO | 156 | g/GJ | 97 | 255 | DBFZ 2011 |
| NMVOC | 10 | g/GJ | 3 | 18 | Nielsen et al. 2010 |
| SOx | 10.8 | g/GJ | 32 | 182 | DBFZ 2011 |
| NH3 | 0.23 | g/GJ | - | - | DBFZ 2011 |
| Pb | <0.005 | mg/GJ | - | - | Nielsen et. al. 2010 |
| Cd | <0.002 | mg/GJ | - | - | Nielsen et. al. 2010 |
| Hg | <0.12 | mg/GJ | - | - | Nielsen et. al. 2010 |
| As | <0.042 | mg/GJ | - | - | Nielsen et. al. 2010 |
| Cr | 0.18 | mg/GJ | - | - | Nielsen et. al. 2010 |
| Cu | 0.31 | mg/GJ | - | - | Nielsen et. al. 2010 |
| Ni | 0.23 | mg/GJ | - | - | Nielsen et. al. 2010 |
| Se | <0.21 | mg/GJ | - | - | Nielsen et. al. 2010 |
| Zn | 4 | mg/GJ | - | - | Nielsen et. al. 2010 |
| PCDD/F | <0.96 | ng/GJ | - | - | Nielsen et. al. 2010 |

Note: If activity data is not available in Joules but electricity generation from biogas is known, the following emission factors can be used: NOx: 1.95 g/kWh el., CO: 1.54 g/kWh el., SOx : 0.86 g/kWh el., NH3: 0.0023 g/kWh el.

All heavy metal emission factors and NH3 are derived from just one sample. Most of the heavy metal measurement were below the limit of quantification.

#### Tier 1 activity data

Information on the use of energy and production of power, suitable for estimating emissions using the Tier 1 simpler estimation methodology, is available from national statistics agencies or the International Energy Agency (IEA).

Further guidance is provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, volume 2 on Stationary Combustion   
www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2\_Volume2/V2\_2\_Ch2\_Stationary\_Combustion.pdf

The activity rate and the emission factor have to be determined on the same level of aggregation depending on the availability of data. The activity statistic should be determined within the considered country or region by using adequate statistics. The activity should refer to the energy input of the emission sources considered (net or inferior fuel consumption in [GJ]).

### Tier 2 technology-specific approach

#### Algorithm

The Tier 2 approach is similar to the Tier 1 approach. To apply the Tier 2 approach, both the activity data and the emission factors need to be applied according to a country’s fuel usage and installed combustion technologies. These techniques may include:

* relative mix of fuels,
* types of combustion plant.

There are two approaches possible:

disaggregate the fuel use in the country to model the different combustion and abatement types into the inventory by

1. defining the activity data using each of the identified process types (together called ‘technologies’ in the formulae below) separately, and
2. applying technology-specific emission factors for each process type:

 (2)

develop country-specific emission factors from the understanding of the relative contributions of the different technologies within the national combustion plant portfolio (and relative fuel use) and apply this country-specific emission factor for the national fuel use.

 (3)

Both approaches are mathematically very similar or even identical. Using one or the other approach depends mainly on the availability of data. If the activity data are indeed available, the first approach seems to be more appropriate. If, however, no direct activity data are available, penetration of different technologies within the industry could be estimated from data on capacities, or other surrogate data that reflect relative sizes of facilities using the different technologies.

#### Technology-specific emission factors

Applying a Tier 2 approach for the process emissions from public power and heat production, technology-specific emission factors are needed. The main technology distinction is by combustion unit type (boiler technologies, gas turbine, stationary engine) and fuel type. Note that factors for smaller combustion units (< 50 MWth) are provided in Chapter 1.A.4, where available, size-based factors for boilers are also provided for. Example factors are provided in this section; however, it should be noted that these cannot address every fuel, combustion and abatement combination that can exist. The number of sources in this activity is usually comparatively small and the inventory compiler may wish to consider gathering data to allow a Tier 3 approach as a more robust methodology. Knowledge of emission concentrations and emission limit values (ELVs) can allow a first estimation of emission factors without detailed knowledge of plant combustion and abatement technology.

Emission factors derived from the achievable emission levels values (AELs) as defined in the BREF document are provided in subsection 6.3.1 for comparison. In addition, ELVs for selected emission instruments are provided as emission factors in Appendix D.

Table 3‑8 Technology-specific Tier 2 factors

|  |  |
| --- | --- |
| Combustion technology | Relevant fuels |
| Dry bottom boiler | Coking coal, steam coal, sub-bituminous coal, brown coal, lignite, wood, peat, coke, oven coke, residual oil, natural gas |
| Wet bottom boiler | Coking coal, steam coal, sub-bituminous coal, brown coal, lignite, |
| Fluid bed boiler | Hard coal, brown coal |
| Gas turbine | Natural gas, gas oil, refinery gas, blast furnace gas |
| Stationary engine | Natural gas, gas oil |

This section provides a series of technology-specific pollutant emission factors for combustion; these factors represent a wider range of fuels and combustion technologies than for Tier 1. They do not represent specific combustion and abatement technologies (which would be needed in a Tier 3 approach), but do offer more disaggregation than Tier 1. Extension of Tier 2 to reflect emission abatement is possible through use of factors derived from emission data.

The BC emission factors presented in this Guidance are derived on the basis of EC and it is therefore assumed that BC=EC.

Tier 2 emission factors are provided for the main pollutants: NOx, CO, NMVOC, SOx, PM and BC. Only in a few cases are Tier 2 emission factors for heavy metals and POPs available. In all the other cases Tier 1 emission factors should be used.

Table 3‑9 Tier 2 emission factors for source category 1.A.1.a, dry bottom boilers using coking coal, steam coal and sub-bituminous coal

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| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Coking Coal, Steam Coal & Sub-Bituminous Coal | | | | |
| **SNAP (if applicable)** | 010101 010102 | Public power - Combustion plants >= 300 MW (boilers) Public power - Combustion plants >= 50 and < 300 MW (boilers) | | | |
| **Technologies/Practices** | Dry Bottom Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | Abatement assumed except for SO2 EF | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 209 | g/GJ | 200 | 350 | US EPA (1998), chapter 1.1 |
| CO | 8.7 | g/GJ | 6.15 | 15 | US EPA (1998), chapter 1.1 |
| NMVOC | 1.0 | g/GJ | 0.6 | 2.4 | US EPA (1998), chapter 1.1 |
| SOx | 820 | g/GJ | 330 | 5000 | See Note |
| TSP | 11.4 | g/GJ | 3 | 300 | US EPA (1998), chapter 1.1 |
| PM10 | 7.7 | g/GJ | 2 | 200 | US EPA (1998), chapter 1.1 |
| PM2.5 | 3.4 | g/GJ | 0.9 | 90 | US EPA (1998), chapter 1.1 |
| BC | 2.2 | % of PM2.5 | 0.27 | 8.08 | See Note |
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Notes:

For conversion of the US EPA data the heating value as provided in the reference has been used (26 MMBTU/ton). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb. The EFs for benzo(b)fluoranthene and benzo(k)fluoranthene are converted using the average NCV for other bituminous coal of 24.1 GJ/ton from Energy Statistics Manual (OECD/IEA, 2005).

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The BC share is derived as the average of data from Henry & Knapp (1980), Olmez et al. (1988), Watson et al. (2001), Fisher et al. (1979), Griest & Tomkins (1984), Engelbrecht et al. (2002), Chow et al. (2004) and Speciate (US EPA, 2011).

The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions and are based on an ash content of 8.2%. Note that condensable PM emission factors are also provided in US EPA (1998), Chapter 1.1.

Heavy metal and POPs emission factors are not available for the Tier 2 approach. Please use Tier 1 emission factors.

Table 3‑10 Tier 2 emission factors for source category 1.A.1.a, wet and dry bottom boilers using brown coal/lignite

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| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Brown Coal/Lignite | | | | |
| **SNAP (if applicable)** | 010101 010102 | Public power - Combustion plants >= 300 MW (boilers) Public power - Combustion plants >= 50 and < 300 MW (boilers) | | | |
| **Technologies/Practices** | Wet and Dry Bottom Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | BC, NH3 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 247 | g/GJ | 143 | 571 | US EPA (1998), chapter 1.7 |
| CO | 8.7 | g/GJ | 6.72 | 60.5 | US EPA (1998), chapter 1.7 |
| NMVOC | 1.4 | g/GJ | 0.84 | 3.36 | US EPA (1998), chapter 1.7 |
| SOx | 1680 | g/GJ | 330 | 5000 | See Note |
| TSP | 11.7 | g/GJ | 1.2 | 117 | US EPA (1998), chapter 1.7 |
| PM10 | 7.9 | g/GJ | 1 | 79 | US EPA (1998), chapter 1.7 |
| PM2.5 | 3.2 | g/GJ | 1 | 32 | US EPA (1998), chapter 1.7 |
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Notes:

For conversion of the US EPA data the heating value as provided in the reference has been used (6500 BTU/lb). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU, 2000 lb/ton and 453.59237 g/lb. The EFs for Cu and Zn are converted using the average NCV 11.9 GJ/Mg from IPCC Guidelines (IPCC, 2006).

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions and are based on an ash content of 5%. Note that condensable PM emission factors are also provided in US EPA (1998), Chapter 1.7.

Heavy metal and POPs emission factors are not available for the Tier 2 approach. Please use Tier 1 emission factors.

Table 3‑11 Tier 2 emission factors for source category 1.A.1.a, boilers using residual oil and heavy fuel oil

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Residual Oil | | | | |
| **SNAP (if applicable)** | 010101 010102 | Public power - Combustion plants >= 300 MW (boilers) Public power - Combustion plants >= 50 and < 300 MW (boilers) | | | |
| **Technologies/Practices** | Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, PCBs, Benzo(a)pyrene, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 142 | g/GJ | 70 | 300 | US EPA (2010), chapter 1.3 |
| CO | 15.1 | g/GJ | 9.06 | 21.1 | US EPA (2010), chapter 1.3 |
| NMVOC | 2.3 | g/GJ | 1.4 | 3.2 | US EPA (2010), chapter 1.3 |
| SOx | 495 | g/GJ | 146 | 1700 | See Note |
| TSP | 35.4 | g/GJ | 2 | 200 | US EPA (2010), chapter 1.3 |
| PM10 | 25.2 | g/GJ | 1.5 | 150 | US EPA (2010), chapter 1.3 |
| PM2.5 | 19.3 | g/GJ | 0.9 | 90 | US EPA (2010), chapter 1.3 |
| BC | 5.6 | % of PM2.5 | 0.22 | 8.69 | See Note |
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Note:

For conversion of the US EPA data the heating value as provided in the reference has been used (150 MMBTU/103 gal). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The BC emission factor is derived as the average of the data found in Olmez et al. (1988), England et al. (2007) and the Speciate database (US EPA, 2011).

The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions and are based on a sulphur content of 1%. Note that condensable PM emission factors are also provided in US EPA (1998), Chapter 1.3.

Heavy metal and POPs emission factors are not available for the Tier 2 approach. Please use Tier 1 emission factors.

Table 3‑12 Tier 2 emission factors for source category 1.A.1.a, boilers using natural gas

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Natural Gas | | | | |
| **SNAP (if applicable)** | 010101 010102 | Public power - Combustion plants >= 300 MW (boilers) Public power - Combustion plants >= 50 and < 300 MW (boilers) | | | |
| **Technologies/Practices** | Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** | BC, PCDD/F, PCBs, HCB | | | | |
| **Not estimated** | NH3, | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 89 | g/GJ | 15 | 185 | US EPA (1998), chapter 1.4 |
| CO | 39 | g/GJ | 20 | 60 | US EPA (1998), chapter 1.4 |
| NMVOC | 2.6 | g/GJ | 0.65 | 10.4 | US EPA (1998), chapter 1.4 |
| SOx | 0.244 | g/GJ | <0.030 | 0.458 | DBI 2014, Fluxys 2009-2011 |
| TSP | <0.14 | g/GJ | <0.09 | <0.19 | UBA 2019 |
| PM10 | <0.14 | g/GJ | <0.09 | <0.19 | UBA 2019 |
| PM2.5 | <0.14 | g/GJ | <0.09 | <0.19 | UBA 2019 |
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Notes:

For conversion of the US EPA data the heating value as provided in the reference has been used (1.02 BTU/scf). This has been converted to NCV using a factor of 0.90. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The factor for SOx is based on approximately 0.01 g/m3 mass sulphur content.

Some of the SOx, TSP, PM10 and PM2.5 emission factors are below the limit of determination.

Table 3‑13 Tier 2 emission factors for source category 1.A.1.a, dry bottom boilers using wood and wood waste

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Wood and wood waste (clean wood waste) | | | | |
| **SNAP (if applicable)** | 010101 010102 | Public power - Combustion plants >= 300 MW (boilers) Public power - Combustion plants >= 50 and < 300 MW (boilers) | | | |
| **Technologies/Practices** | Dry Bottom Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | **Primary NOx abatement – no PM abatement** | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 81 | g/GJ | 40 | 160 | Nielsen et al., 2010 |
| CO | 90 | g/GJ | 45 | 180 | Nielsen et al., 2010 |
| NMVOC | 7.31 | g/GJ | 2.44 | 21.9 | US EPA (2003), chapter 1.6 |
| SOx | 10.8 | g/GJ | 6.45 | 15.1 | US EPA (2003), chapter 1.6 |
| TSP | 172 | g/GJ | 86 | 344 | US EPA (2003), chapter 1.6 |
| PM10 | 155 | g/GJ | 77 | 310 | US EPA (2003), chapter 1.6 |
| PM2.5 | 133 | g/GJ | 66 | 266 | US EPA (2003), chapter 1.6 |
| BC | 3.3 | % of PM2.5 | 1.6 | 6.6 | See Note |
| Pb | 20.6 | mg/GJ | 12.4 | 28.9 | US EPA (2003), chapter 1.6 |
| Cd | 1.76 | mg/GJ | 1.06 | 2.47 | US EPA (2003), chapter 1.6 |
| Hg | 1.51 | mg/GJ | 0.903 | 2.11 | US EPA (2003), chapter 1.6 |
| As | 9.46 | mg/GJ | 5.68 | 13.2 | US EPA (2003), chapter 1.6 |
| Cr | 9.03 | mg/GJ | 5.42 | 12.6 | US EPA (2003), chapter 1.6 |
| Cu | 21.1 | mg/GJ | 12.6 | 29.5 | US EPA (2003), chapter 1.6 |
| Ni | 14.2 | mg/GJ | 8.51 | 19.9 | US EPA (2003), chapter 1.6 |
| Se | 1.2 | mg/GJ | 0.722 | 1.69 | US EPA (2003), chapter 1.6 |
| Zn | 181 | mg/GJ | 108 | 253 | US EPA (2003), chapter 1.6 |
| PCB | 3.5 | µg/GJ | 0.35 | 35 | US EPA (2003), chapter 1.6 |
| PCDD/F | 50 | ng I-TEQ/GJ | 25 | 75 | UNEP (2005) (for clean wood) |
| Benzo(a)pyrene | 1.12 | mg/GJ | 0.671 | 1.57 | US EPA (2003), chapter 1.6 |
| Benzo(b)fluoranthene | 0.043 | mg/GJ | 0.0215 | 0.0645 | US EPA (2003), chapter 1.6 |
| Benzo(k)fluoranthene | 0.0155 | mg/GJ | 0.00774 | 0.0232 | US EPA (2003), chapter 1.6 |
| Indeno(1,2,3-cd)pyrene | 0.0374 | mg/GJ | 0.0187 | 0.0561 | US EPA (2003), chapter 1.6 |
| HCB | 5 | µg/GJ | 0.5 | 50 | Bailey, 2001 |

Note: For conversion of the US EPA data units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The BC emission factor is an average of the data in Dayton & Bursey (2001) and the Speciate database (US EPA, 2011).

The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions. Note that a condensable PM emission factor is also provided in US EPA (1998), Chapter 1.6.

Table 3‑14 Tier 2 emission factors for source category 1.A.1.a, wet bottom boilers using coking coal, steam coal and sub-bituminous coal

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Coking Coal, Steam Coal & Sub-Bituminous Coal | | | | |
| **SNAP (if applicable)** | 010101 010102 | Public power - Combustion plants >= 300 MW (boilers) Public power - Combustion plants >= 50 and < 300 MW (boilers) | | | |
| **Technologies/Practices** | Wet Bottom Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | Abatement assumed except for SO2 | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 244 | g/GJ | 120 | 488 | US EPA (1998), chapter 1.1 |
| CO | 8.7 | g/GJ | 6.15 | 150 | US EPA (1998), chapter 1.1 |
| NMVOC | 0.7 | g/GJ | 0.4 | 1.6 | US EPA (1998), chapter 1.1 |
| SOx | 820 | g/GJ | 330 | 5000 | See Note |
| TSP | 8.0 | g/GJ | 7.5 | 30 | US EPA (1998), chapter 1.1 |
| PM10 | 6.0 | g/GJ | 6 | 24 | US EPA (1998), chapter 1.1 |
| PM2.5 | 3.1 | g/GJ | 3 | 12 | US EPA (1998), chapter 1.1 |
| BC | 2.2 | % of PM2.5 | 0.27 | 8.08 | See Note |
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Note: For conversion of the US EPA data the heating value as provided in the reference has been used (26 MMBTU/ton). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb. The EFs for benzo(b)fluoranthene and benzo(k)fluoranthene are converted using the average NCV for other bituminous coal of 24.1 GJ/ton from Energy Statistics Manual (OECD/IEA, 2005).

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The BC share is derived as the average of data from Henry & Knapp (1980), Olmez et al. (1988), Watson et al. (2001), Fisher et al. (1979), Griest & Tomkins (1984), Engelbrecht et al. (2002), Chow et al. (2004) and Speciate (US EPA, 2011).

The TSP, PM10 and PM2.5 emission factors provided in US EPA (1998) Chapter 1.1 represent filterable PM emissions and are determined from fuel ash content. Note that condensable PM emission factors are also provided in US EPA (1998), Chapter 1.1.

Heavy metal and POPs emission factors are not available for the Tier 2 approach. Please use Tier 1 emission factors.

Table 3‑15 Tier 2 emission factors for source category 1.A.1.a, fluid bed boilers using hard coal

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| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Hard Coal | | | | |
| **SNAP (if applicable)** | 010101 010102 | Public power - Combustion plants >= 300 MW (boilers) Public power - Combustion plants >= 50 and < 300 MW (boilers) | | | |
| **Technologies/Practices** | Fluid Bed Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | Abatement assumed except for SO2 | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 82.5 | g/GJ | 10 | 112 | European Commission (2006) |
| CO | 313 | g/GJ | 150 | 600 | US EPA (1998), chapter 1.1 |
| NMVOC | 0.9 | g/GJ | 0.6 | 2.4 | US EPA (1998), chapter 1.1 |
| SOx | 820 | g/GJ | 330 | 5000 | See Note |
| TSP | 8.4 | g/GJ | 7.5 | 30 | US EPA (1998), chapter 1.1 |
| PM10 | 7.7 | g/GJ | 6 | 24 | US EPA (1998), chapter 1.1 |
| PM2.5 | 5.2 | g/GJ | 3 | 12 | US EPA (1998), chapter 1.1 |
| BC | 2.2 | % of PM2.5 | 0.27 | 8.08 | See Note |
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Note: For conversion of the US EPA data the heating value as provided in the reference has been used (26 MMBTU/ton). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb. The EFs for benzo(b)fluoranthene and benzo(k)fluoranthene are converted using the average NCV for other bituminous coal of 24.1 GJ/ton from Energy Statistics Manual (OECD/IEA, 2005).

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The BC share is derived as the average of data from Henry & Knapp (1980), Olmez et al. (1988), Watson et al. (2001), Fisher et al. (1979), Griest & Tomkins (1984), Engelbrecht et al. (2002), Chow et al. (2004) and Speciate (US EPA, 2011).  
The basis of the TSP, PM10 and PM2.5 emission factors could not be determined in the reference.

Heavy metal and POPs emission factors are not available for the Tier 2 approach. Please use Tier 1 emission factors.

Table 3‑16 Tier 2 emission factors for source category 1.A.1.a, fluid bed boilers using brown coal

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Brown Coal | | | | |
| **SNAP (if applicable)** | 010101 010102 | Public power - Combustion plants >= 300 MW (boilers) Public power - Combustion plants >= 50 and < 300 MW (boilers) | | | |
| **Technologies/Practices** | Fluid Bed Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | BC, NH3 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 60 | g/GJ | 35 | 85.2 | European Commission (2006) |
| CO | 13 | g/GJ | 0.1 | 26 | European Commission (2006) |
| NMVOC | 1 | g/GJ | 0.2 | 5 | US EPA (1998), chapter 1.7 |
| SOx | 1680 | g/GJ | 330 | 5000 | See Note |
| TSP | 10.2 | g/GJ | 3.4 | 30.6 | US EPA (1998), chapter 1.7 |
| PM10 | 6.9 | g/GJ | 2.3 | 20.7 | US EPA (1998), chapter 1.7 |
| PM2.5 | 2.8 | g/GJ | 0.9 | 8.4 | US EPA (1998), chapter 1.7 |
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Note:

For conversion of the US EPA data the heating value as provided in the reference has been used (6500 BTU/lb). This has been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU, 2000 lb/ton and 453.59237 g/lb. The EFs for Cu and Zn are converted using the average NCV 11.9 GJ/Mg from IPCC Guidelines (IPCC, 2006).

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The emission factors for PCBs, benzo(b)fluoranthene, benzo(k)fluoranthene and HCB are based on data for hard coal combusted in FBB.

The basis of the TSP, PM10 and PM2.5 emission factors could not be determined in the reference.

Heavy metal and POPs emission factors are not available for the Tier 2 approach. Please use Tier 1 emission factors.

Table 3‑17 Tier 2 emission factors for source category 1.A.1.a, gas turbines using gaseous fuels

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Gaseous Fuels | | | | |
| **SNAP (if applicable)** | 010104 | Public power - Gas turbines | | | |
| **Technologies/Practices** | Gas Turbines | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** | BC, PCB, PCDD/F, HCB | | | | |
| **Not estimated** | NH3, | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 48 | g/GJ | 28 | 68 | Nielsen et al., 2010 |
| CO | 4.8 | g/GJ | 1 | 70 | Nielsen et al., 2010 |
| NMVOC | 1.6 | g/GJ | 0.5 | 7.6 | Nielsen et al., 2010 |
| SOx | 0.244 | g/GJ | <0.030 | 0.458 | DBI 2014, Fluxys 2009-2011 |
| TSP | <0.2 | g/GJ | <0.05 | 0.8 | BUWAL, 2001 |
| PM10 | <0.2 | g/GJ | <0.05 | 0.8 | Assumed equal to TSP |
| PM2.5 | <0.2 | g/GJ | <0.05 | 0.8 | Assumed equal to TSP |
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Notes:

TThe basis of the TSP, PM10 and PM2.5 emission factors could not be determined in the reference.

Table 3‑18 Tier 2 emission factors for source category 1.A.1.a, gas turbines using gas oil

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Gas Oil | | | | |
| **SNAP (if applicable)** | 010104 | Public power – gas turbines | | | |
| **Technologies/Practices** | Gas Turbines | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, As, Cu, Ni, Se, Zn, PCB, PCDD/F, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, Indeno(1,2,3-cd)pyrene, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 398 | g/GJ | 239 | 557 | US EPA (2000), chapter 3.1 |
| CO | 1.49 | g/GJ | 0.89 | 2.09 | US EPA (2000), chapter 3.1 |
| NMVOC | 0.19 | g/GJ | 0.11 | 0.26 | US EPA (2000), chapter 3.1 |
| SOx | 46.5 | g/GJ | 4.65 | 465 | See Note |
| TSP | 1.95 | g/GJ | 0.65 | 5.85 | US EPA (2000), chapter 3.1 |
| PM10 | 1.95 | g/GJ | 0.65 | 5.85 | US EPA (2000), chapter 3.1 |
| PM2.5 | 1.95 | g/GJ | 0.65 | 5.85 | US EPA (2000), chapter 3.1 |
| BC | 33.5 | % of PM2.5 | 28.9 | 38 | Hildemann et al., 1981 & Bond et al., 2006 |
| Pb | 0.0069 | mg/GJ | 0.0007 | 0.069 | Pulles et al. (2012) |
| Cd | 0.0012 | mg/GJ | 0.0001 | 0.012 | Pulles et al. (2012) |
| Hg | 0.053 | mg/GJ | 0.005 | 0.53 | Pulles et al. (2012) |
| As | 0.0023 | mg/GJ | 0.0002 | 0.023 | Pulles et al. (2012) |
| Cr | 0.28 | mg/GJ | 0.23 | 0.30 | Pulles et al. (2012) |
| Cu | 0.17 | mg/GJ | 0.14 | 0.20 | Pulles et al. (2012) |
| Ni | 0.0023 | mg/GJ | 0.0002 | 0.023 | Pulles et al. (2012) |
| Se | 0.0023 | mg/GJ | 0.0002 | 0.023 | Pulles et al. (2012) |
| Zn | 0.44 | mg/GJ | 0.37 | 0.51 | Pulles et al. (2012) |

Note:

For conversion of the US EPA data the values have been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The factor for SOx is based on 0.1 % mass sulphur content.

Due to lack of data the BC emission factor refers to gas oil fired boilers.The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions. Note that a condensable PM emission factor is also provided in US EPA (2000), Chapter 3.1.

Table 3‑19 Tier 2 emission factors for source category 1.A.1.a, reciprocating engines using gas oil

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | Gas Oil | | | | |
| **SNAP (if applicable)** | 010105 | Public power - Stationary engines | | | |
| **Technologies/Practices** | Large stationary CI reciprocating engines | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3 | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 942 | g/GJ | 500 | 1380 | Nielsen et al., 2010 |
| CO | 130 | g/GJ | 30 | 230 | Nielsen et al., 2010 |
| NMVOC | 37.1 | g/GJ | 18.5 | 55.6 | US EPA (1996), chapter 3.4 |
| SOx | 46.5 | g/GJ | 4.65 | 465 | See Note |
| TSP | 28.1 | g/GJ | 14.1 | 56.2 | US EPA (1996), chapter 3.4 |
| PM10 | 22.4 | g/GJ | 11.2 | 44.8 | US EPA (1996), chapter 3.4 |
| PM2.5 | 21.7 | g/GJ | 10.8 | 43.4 | US EPA (1996), chapter 3.4 |
| BC | 78 | % of PM2.5 | 63 | 93 | Hernandez et al., 2004 |
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| PCDD/F | 0.99 | ng I-TEQ/GJ | 0.1 | 10 | Nielsen et al., 2010 |
| HCB | 0.22 | µg/GJ | 0.022 | 2.2 | Nielsen et al., 2010 |
| PCBs | 0.13 | ng I-TEQ/GJ | 0.013 | 1.3 | Nielsen et al., 2010 |
| Benzo(a)pyrene | <0.116 | mg/GJ | <0.0582 | <0.116 | US EPA (1996), chapter 3.4 ("Less than" value based on method detection limits) |
| Benzo(b)fluoranthene | <0.502 | mg/GJ | <0.251 | <0.754 | US EPA (1996), chapter 3.4 |
| Benzo(k)fluoranthene | <0.0987 | mg/GJ | <0.0493 | <0.0987 | US EPA (1996), chapter 3.4 ("Less than" value based on method detection limits) |
| Indeno(1,2,3-cd)pyrene | <0.187 | mg/GJ | <0.0937 | <0.187 | US EPA (1996), chapter 3.4 ("Less than" value based on method detection limits) |

Notes:

For conversion of the US EPA data the values have been converted to NCV using a factor of 0.95. Furthermore, units have been converted using 1055.0559 J/BTU and 453.59237 g/lb.

The factor for SOx assumes no SO2 abatement and is based on 0.1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter.The TSP, PM10 and PM2.5 emission factors represent filterable PM emissions. Note that a condensable PM emission factor is also provided in US EPA (1996), Chapter 3.4.

Heavy metal emission factors are not available for the Tier 2 approach. Please use Tier 1 emission factors.

Table 3‑20 Tier 2 emission factors for source category 1.A.1.a, reciprocating engines using natural gas

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.a | Public electricity and heat production | | | |
| **Fuel** | **Natural gas** | | | | |
| **SNAP (if applicable)** | 010105 | Public power - Stationary engines | | | |
| **Technologies/Practices** | Stationary reciprocating Engines - gas-fired | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, PCBs, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 135 | g/GJ | 65 | 200 | Nielsen et al., 2010 |
| CO | 56 | g/GJ | 20 | 135 | Nielsen et al., 2010 |
| NMVOC | 89 | g/GJ | 45 | 135 | Nielsen et al., 2010 |
| SO2 | 0.5 | g/GJ | 0.1 | 1 | BUWAL, 2001 |
| TSP | 2 | g/GJ | 1 | 3 | BUWAL, 2001 |
| PM10 | 2 | g/GJ | 1 | 3 | BUWAL, 2001 |
| PM2.5 | 2 | g/GJ | 1 | 3 | BUWAL, 2001 |
| BC | 2.5 | % of PM2.5 | 1 | 6.3 | See Note |
| Pb | <0.04 | mg/GJ | <0.008 | 0.2 | Nielsen et al., 2010 |
| Cd | <0.003 | mg/GJ | <0.0006 | <0.015 | Nielsen et al., 2010 |
| Hg | 0.1 | mg/GJ | 0.02 | 0.5 | Nielsen et al., 2010 |
| As | <0.05 | mg/GJ | <0.01 | 0.25 | Nielsen et al., 2010 |
| Cr | <0.05 | mg/GJ | <0.01 | 0.25 | Nielsen et al., 2010 |
| Cu | <0.01 | mg/GJ | <0.002 | <0.05 | Nielsen et al., 2010 |
| Ni | <0.05 | mg/GJ | <0.01 | 0.25 | Nielsen et al., 2010 |
| Se | 0.2 | mg/GJ | 0.04 | 1 | Nielsen et al., 2010 |
| Zn | 2.91 | mg/GJ | 0.6 | 14.6 | Nielsen et al., 2010 |
| PCDD/F | 0.57 | ng I-TEQ/GJ | 0.28 | 1.2 | Nielsen et al., 2010 |
| Benzo(a)pyrene | 1.20 | µg/GJ | 0.24 | 6 | Nielsen et al., 2010 |
| Benzo(b)fluoranthene | 9.00 | µg/GJ | 1.8 | 45 | Nielsen et al., 2010 |
| Benzo(k)fluoranthene | 1.70 | µg/GJ | 0.34 | 8.5 | Nielsen et al., 2010 |
| Indeno(1,2,3-cd)pyrene | 1.80 | µg/GJ | 0.36 | 9 | Nielsen et al., 2010 |

Notes:

SO2 emission factor can also be calculated using EF calculation from subsection 3.4.2.2 of the present chapter.

The BC emission factor is the average of the data available in England et al. (2004), Wien et al. (2004) and the Speciate database (US EPA, 2011).

The basis of the TSP, PM10 and PM2.5 emission factors could not be determined in the reference.

PCDD/F, PCB, HCB and the larger part of NMVOC emissions are from lubricant use but not from natural gas combustion.

#### Abatement

A number of technologies exist that are aimed at reducing the emissions of specific pollutants. The resulting emission can be calculated by applying an abated emission factor as given in the formula:

 (5)

However, this approach requires knowledge of emissions for the unabated or ‘baseline’ technology and abatement efficiency, which may be difficult to obtain.

Abatement performance is rarely expressed in terms of efficiency, but in terms of the achievable or guaranteed emission concentration (for example to achieve compliance with an emission limit value). Assessment of abatement performance is almost always determined by measurement of emitted concentrations. To allow users to assess if the Tier 2 emission factors for technologies can be reasonably applied to their country, subsection 6.3, Verification, of the present chapter provides guidance on conversion of emission concentrations (measured concentrations or emission limit values) into emission factors for selected fuels.

#### Activity data

Information on the production of power which is suitable for estimating emissions using the simpler estimation methodology (Tier 1 and 2) is available from national statistics agencies or the International Energy Agency (IEA).

Further guidance is provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, volume 2 on Stationary Combustion [www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2\_Volume2/V2\_2\_Ch2\_Stationary\_Combustion.pdf](http://cfpub.epa.gov/si/speciate/).

For a Tier 2 approach these data need to be stratified according to technologies applied. Typical sources for this data might be industrial or regulatory organisations within the country or from specific questionnaires to the individual combustion installations.

### Tier 3 use of facility-specific data

#### Algorithm

Where facility-level emission data of sufficient quality (see Chapter 3, Data collection, in part A) are available, it is good practice to use these data. There are two possibilities:

* the facility reports cover all relevant combustion processes in the country;
* facility-level emission reports are not available for all relevant combustion processes in the country.

If facility-level data are available covering all activities in the country, the implied emission factors (reported emissions divided by the national fuel use) should be compared with the default emission factor values or technology-specific emission factors. If the implied emission factors are outside the 95 % confidence intervals for the values given, it is good practice to explain the reasons for this in the inventory report

Depending on the specific national circumstances and the coverage of the facility-level reports as compared to the total combustion activity, the emission factor (EF) in this equation should be chosen from the following possibilities, in decreasing order of preference:

* technology-specific emission factors, based on knowledge of the types of technologies implemented at the facilities where facility-level emission reports are not available;
* the implied emission factor derived from the available emission reports:

 (7)

* the default Tier 1 emission factor. This option should only be chosen if the facility-level emission reports cover more than *90 %* of the total national production.

Sources of emission factor guidance for facilities include the USEPA (USEPA, AP-42), BREF and industry sector guidance (for example Eurelectric (The Union of the Electricity Industry), 2008). Emission concentration data and ELVs can also be used by inventory compilers to develop emission factors (Appendix E). The older versions of the Guidebook also provided a range of emission factors which may be of use and these are provided at Appendix F.

#### Tier 3 use of facility data

Many combustion installations are major facilities and emission data for individual plants might be available through a pollutant release and transfer registry (PRTR) or another national emission reporting scheme. The electricity sector is developing guidance on estimating emissions (Eurelectric, 2008). When the quality of such data is assured by a well developed QA/QC system and the emission reports have been verified by an independent auditing scheme, it is good practice to use such data. If extrapolation is needed to cover all activity in the country either the implied emission factors for the facilities that did report, or the emission factors as provided above could be used (see subsection 3.4.3.2).

#### Activity data

Since PRTR generally do not report activity data, such data in relation to the reported facility-level emissions are sometimes difficult to find. For large combustion plants in Europe fuel data is available from the LCP reporting. Another possible source of facility-level activity might be the registries of emission trading systems. However, the systems do not always have the same structure.

In many countries national statistics offices collect production data on facility level, but these are in many cases confidential. However, in several countries, national statistics offices are part of the national emission inventory systems and the extrapolation, if needed, could be performed at the statistics office, ensuring that confidentiality of production data is maintained.

# 1.A.1.b Petroleum refining

## Techniques

Details of technologies used in this activity can be found within the Best Available Techniques Reference Note (BREF) for refining installations (EIPPCB, 2015).

### Process energy

Refineries require electrical and thermal energy in substantial quantities. Electrical and thermal energy is typically generated by combined heat and power (CHP) or cogeneration facilities at the refinery. Thermal energy can be provided directly (process furnaces on the production unit) or via steam produced within the production unit or from a utilities facility. The technologies for production of energy from combustion can be identical to those for 1.A.1.a, activities but in many instances the difference will be that the fuels utilised will be refinery gaseous and liquid fuels. Where non-refinery fuels are used in combustion processes the information provided in the 1.A.1.a activity can be applied.

### Production activities

Many production activities incorporate process furnaces to heat feedstock; these may use refinery fuels and recover refinery by-products, and these will have associated combustion emissions. Incineration and flaring of refinery by-products are other combustion activities (see Chapter 1.B.2.c). In addition, process sources include bitumen blowing, blowdown systems, hydrogen plant, fluid coking units, fluidised catalytic cracking (FCC) units and catalytic reforming units (see Chapter 1.B.2.a.iv).

## Emissions

Note that the inventory methodologies for Greenhouse gas emissions (carbon dioxide, methame and nitrous oxide) are not included – refer to IPCC guidance [IPCC, 2006].

##### Sulphur oxides

Most emissions arise from process furnaces, boilers, sulphur recovery units, FCC regenerators, flares, incinerators and decoking units. In the absence of flue gas desulphurisation (FGD) technology, the emissions of sulphur oxides (SOx) are directly related to the sulphur content of the fuel. The majority of SOx is sulphur dioxide (SO2) although small proportions of sulphur trioxide (SO3) can arise.

##### Nitrogen oxides

Emissions of nitrogen oxides (nitric oxide and nitrogen dioxide — NOx) arise primarily from combustion and the FCC unit. Combustion control can provide a high degree of NOx emission control (low NOx burner technology) and this may be supplemented by use of selective catalytic reduction (SCR) or selective non catalytic reduction techniques (SNCR).

##### Non-methane volatile organic compounds (NMVOC)

Emissions of non-methane volatile organic compounds (NMVOC) can result from combustion activities (including flaring) and process discharges such as vents and blowdown systems. However, many emission sources on refineries tend to be fugitive releases (See chapter 1.B.2a.iv).

##### Carbon monoxide (CO)

Apart from combustion, flaring and incineration activities, the FCC and catalytic reforming units can produce CO, but include CO boilers (thermal oxidisers) to control emissions.

##### Ammonia (NH3)

Emissions can result from incomplete reaction of NH3 additive in NOx abatement systems — selective catalytic and non-catalytic reduction (SCR and SNCR). Regenerators for FCC units may emit ammonia, but these emissions are eliminated by use of CO boilers. In addition, refrigeration systems which use ammonia may have an associated emission.

##### Particulate matter

Particulate matter (PM) emissions from refinery operations are associated with combustion activities, and selected production units including coking units and fluid catalytic cracking units.

Note that PM emission factors in the Guidebook represent primary emissions from the activities and not formation of secondary aerosol from chemical reaction in the atmosphere after release.

A number of factors influence the measurement and determination of primary PM emissions from activities and, the quantity of PM determined in an emission measurement depends to a large extent on the measurement conditions. This is particularly true of activities involving high temperature and semi-volatile emission components – in such instances the PM emission may be partitioned between a solid/aerosol phase and material which is gaseous at the sampling point but which can condense in the atmosphere. The proportion of filterable and condensable material will vary depending on the temperature of the flue gases and in sampling equipment.

A range of filterable PM measurement methods are applied around the world typically with filter temperatures of 70-160°C (the temperature is set by the test method).  Condensable fractions can be determined directly by recovering condensed material from chilled impinger systems downstream of a filter – note that this is condensation without dilution and can require additional processing to remove sampling artefacts. Another approach for total PM includes dilution where sampled flue or exhaust gases are mixed with ambient air (either using a dilution tunnel or dilution sampling systems) and the filterable and condensable components are collected on a filter at lower temperatures (but depending on the method this can be 15-52°C). The use of dilution methods for routine measurements on refinery stacks, however, is limited due to practical constraints with weight and/or size of the equipment.

The Guidebook identifies whether the PM emission factors (for TSP, PM10 and PM2.5) represent total PM, filterable PM or whether the basis of the emission factor cannot be determined (see individual emission factor tables).

##### Metals

According to the BREF, important heavy metals in crude oils are As, Hg, Ni, and V. Concawe (Concawe, 2015) also present methodologies for Cd, Cr, Cu, Pb and Zn with sources from combustion, incineration of gaseous streams, FCC regenerators and fluid coking. Nickel and vanadium tend to be enriched in residues from distillation.

## Controls

Details of relevant abatement technologies are described in the BREF notes for refineries and large combustion plant http://eippcb.jrc.ec.europa.eu/reference/. Relevant abatement technologies for refinery combustion units are described in 1.A.1.a. In general, end of pipe treatment of FCC units tends to be similar to the controls for combustion plant.

## Methods

### Choice of method

Figure 4‑1 presents the procedure to select the methods for estimating process emissions from petroleum refining. The basic idea is:

* if detailed information is available, use it;
* if the source category is a key source, a Tier 2 or better method must be applied and detailed input data must be collected. The decision tree directs the user in such cases to the Tier 2 method, since it is expected that it is more easy to obtain the necessary input data for this approach than to collect facility-level data needed for a Tier 3 estimate;
* the alternative of applying a Tier 3 method using detailed process modelling is not explicitly included in this decision tree. However, detailed modelling will always be done at facility level and results of such modelling could be seen as ‘facility data’ in the decision tree.

Figure 4‑1 Decision tree for combustion in petroleum refining



### Tier 1 default approach

#### Algorithm

The Tier 1 approach for process emissions from combustion uses the general equation:

 (1)

*Epollutant* annual emission of pollutant

*EFpollutant* emission factor of pollutant

*ARfuel consumption* activity rate by fuel consumption

This equation is applied at the national level, using annual national total fuel use (disaggregated by fuel type). Information on fuel consumption suitable for estimating emissions using the simpler estimation methodology is widely available from UN statistical yearbooks or national statistics.

The Tier 1 emission factors generally assume an average or typical technology and abatement implementation. However, emission factors for this chapter reflect unabated emissions.

In cases where specific abatement techniques are to be taken into account, a Tier 1 method is not applicable and a Tier 2 or Tier 3 approach must be used.

#### Default emission factors

The default emission factors for combustion activities at Tier 1 are based on fuel types including fuel types common with the 1.A.1.a activity. As most combustion is in process furnaces without contact with the material being heated, Tier 1 default factors for refinery combustion can often be drawn from the 1.A.1.a Tier 1 default factors classifications (see Table 4‑1).

Table 4‑1 Tier 1 fuel classifications

|  |  |  |
| --- | --- | --- |
| Tier 1 fuel type | Associated fuel types | Location |
| Natural gas | Natural gas | See 1.A.l.a Tier 1 |
| Heavy fuel oil | Residual fuel oil, refinery feedstock, petroleum coke | See 1.A.1.a Tier 1 |
| Other liquid fuels | (a) Gas oil, kerosene, naphtha, natural gas liquids, liquefied petroleum gas, orimulsion, bitumen, shale oil  (b) refinery gas | 1. See 1.A.1.a Tier 1 2. Table 4‑2 |

The Tier 1 default emission factors for refinery gas as given in Table 4‑2 have been derived from emission factors published by USEPA (USEPA, 1998) and elsewhere including factors incorporated by the industry sector (Concawe, 2015). In the absence of detail on relative use of combustion or abatement technology, which will be different for each country, the proposed factors represent a mean of unabated emissions for the range of combustion technologies in use with the 95 % figures a measure of the range of unabated emissions in the sector.

Table 4‑2 Tier 1 emission factors for source category 1.A.1.b, refinery gas

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.b | Petroleum refining | | | |
| **Fuel** | Refinery Gas | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, PCDD/F, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| **NOx** | **63** | **g/GJ** | **31.5** | **84.4** | **US EPA (1998), chapter 1.4** |
| CO | 12.1 | g/GJ | 7.3 | 17 | Concawe (2015) |
| NMVOC | 2.58 | g/GJ | 1.29 | 5.15 | US EPA (1998), chapter 1.4 |
| SOx | 10.15 | g/GJ | 1.04 | 21.47 | UBA 2012 |
| TSP | 0.89 | g/GJ | 0.297 | 2.67 | US EPA (1998), chapter 1.4 |
| PM10 | 0.89 | g/GJ | 0.297 | 2.67 | US EPA (1998), chapter 1.4 |
| PM2.5 | 0.89 | g/GJ | 0.297 | 2.67 | US EPA (1998), chapter 1.4 |
| BC | 18.4 | % of PM2.5 | 5.2 | 36.3 | US EPA, 2011 |
| Pb | 1.61 | mg/GJ | 1.2 | 2.1 | Concawe Report 9/16 |
| Cd | 2.19 | mg/GJ | 0.6 | 3.8 | Concawe Report 9/16 |
| Hg | 0.372 | mg/GJ | 0.2 | 0.5 | Concawe Report 9/16 |
| As | 0.352 | mg/GJ | 0.3 | 0.4 | Concawe Report 9/16 |
| Cr | 6.69 | mg/GJ | 0.3 | 13.1 | Concawe Report 9/16 |
| Cu | 3.29 | mg/GJ | 2.4 | 4.2 | Concawe Report 9/16 |
| Ni | 7.37 | mg/GJ | 1.6 | 13.1 | Concawe Report 9/16 |
| Se | 1.56 | mg/GJ | 1.1 | 2.0 | Concawe Report 9/16 |
| Zn | 17.0 | mg/GJ | 12.0 | 22.0 | Concawe Report 9/16 |
| Benzo(a)pyrene | 0.669 | µg/GJ | 0.223 | 2.01 | API (1998, 2002) |
| Benzo(b)fluoranthene | 1.14 | µg/GJ | 0.379 | 3.41 | API (1998, 2002) |
| Benzo(k)fluoranthene | 0.631 | µg/GJ | 0.21 | 1.89 | API (1998, 2002) |
| Indeno(1,2,3-cd)pyrene | 0.631 | µg/GJ | 0.21 | 1.89 | API (1998, 2002) |

Note:

The factor for SOx is based on measurement data from 9 German refineries in 2012 (see subsection 3.4.2.2). All refineries are equipped with desulphurization plants.

These PM factors represent filterable PM emissions only (excluding any condensable fraction).

If a Tier 1 approach is adopted for the process emissions (Chapter 1.B.2.a.iv), combustion emissions are already covered and should not be reported again in Chapter 1.A.1.b since this would lead to double counting.

#### Tier 1 activity data

Information on the use of energy, suitable for estimating emissions using the Tier 1 simpler estimation methodology, is available from national statistics agencies or the International Energy Agency (IEA).

Further guidance is provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, volume 2 on Stationary Combustion   
[www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2\_Volume2/V2\_2\_Ch2\_Stationary\_Combustion.pdf](http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf)

The activity rate and the emission factor have to be determined on the same level of aggregation depending on the availability of data. The activity statistic should be determined within the considered country or region by using adequate statistics. The activity should refer to the energy input of the emission sources considered (net or inferior fuel consumption in [GJ]).

### Tier 2 technology-specific approach

#### Algorithm

The Tier 2 approach is similar to the Tier 1 approach. To apply the Tier 2 approach, both the activity data and the emission factors need to be applied according to a country’s installed combustion and abatement technologies. These techniques may include:

* types of refinery;
* capacities of refineries;
* implementation of abatement technologies in the country.

There are two approaches possible:

disaggregate the fuel use in the country to model the different combustion and abatement types into the inventory by

* defining the activity data using each of the identified process types (together called ‘technologies’ in the formulae below) separately, and
* applying technology-specific emission factors for each process type:

 (2)

develop country-specific emission factors from the understanding of the relative contributions of the different technologies within the national combustion plant portfolio (and relative fuel use) and apply this country-specific emission factor for the national fuel use:

 (3)

Both approaches are mathematically very similar or even identical. Using one or the other approach depends mainly on the availability of data. If the activity data are indeed available, the first approach seems to be more appropriate. If, however, no direct activity data are available, penetration of different technologies within the industry could be estimated from data on capacities, or other surrogate data that reflect relative sizes of facilities using the different technologies.

#### Technology-specific emission factors

Applying a Tier 2 approach for the process emissions from refineries, technology-specific emission factors are needed. Examples are provided in this section. The BREF document for refineries is available at http://eippcb.jrc.ec.europa.eu/reference/ and provides guidance on achievable emission levels. Emission factors derived from the achievable emission levels values (AELs) as defined in the BREF document are provided for comparison in subsection 6.3.1.

This section provides a series of technology-specific pollutant emission factors for combustion units e.g. boilers and process heaters and furnaces; these factors represent a wider range of fuels and combustion technologies than for Tier 1. They do not represent specific combustion technologies but do offer more disaggregation than Tier 1. Many of the factors have been included in the industry guidance for estimating facility releases for E-PRTR (Concawe, 2015) and represent unabated emission factors.

Emission factors for sulphur oxides are provided in the Tier 2 tables. Where countries have knowledge of fuel sulphur content and of abatement technologies then it is recommended that a sulphur oxides emission factor is calculated from fuel sulphur content taking into account abatement efficiency.

A methodology to calculate NOx emissions has been provided in Concawe, 2015 as the sector’s recommended method for refineries to use for emission reporting. However, NOx formation is very complex and depends on a number of parameters (for example hydrogen content, humidity, burner intensity) which may not be available for a Tier 2 methodology.

Extension of Tier 2 to reflect emission abatement is possible through use of factors derived from emission data. For emission factors specific to gas turbines, please see 1.A.1.a, subsection 3.4.3.2, Tier 2 emission factor tables, of the present chapter.

If LPG is used, the emission factors presented for natural gas should be used when estimating emissions.

A summary of the Tier 2 factors is provided in Table 4‑3.

Table 4‑3 Tier 2 default factors

|  |  |  |
| --- | --- | --- |
| Technology | Associated fuel types | Location of Tier 2 factors |
| Process furnaces | Residual oil | Table 4‑4 |
|  | Gas oil | Table 4‑5 |
|  | Refinery gas | See Tier 1 (Table 4‑2) |
|  | Natural gas | Table 4‑7 |
| Gas turbines | Various | See Section 1.A.1.a |
| Gas engines | Natural gas | Table 4‑7 |
| Compression ignition engines | Gas oil | Table 4‑8 |

Table 4‑4 Tier 2 emission factors for source category 1.A.1.b, process furnaces using residual oil

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.b | Petroleum refining | | | |
| **Fuel** | Residual Oil (Refinery Fuel Oil) | | | | |
| **SNAP (if applicable)** | 0103 | Petroleum refining plants | | | |
| **Technologies/Practices** | Process Furnaces, Heaters and Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, Benzo(a)pyrene, Benzo(k)fluoranthene, Indeno(1,2,3-cd)pyrene, PCBs, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 142 | g/GJ | 71 | 284 | US EPA (1998), chapter 1.3 |
| CO | 6 | g/GJ | 3.6 | 8.4 | Concawe (2015) |
| NMVOC | 2.3 | g/GJ | 0.676 | 4.09 | US EPA (1998), chapter 1.3 |
| SOx | 485 | g/GJ | 146 | 1700 | See Note |
| TSP | 20 | g/GJ | 12 | 28 | Visschedijk et al (2004) |
| PM10 | 15 | g/GJ | 9 | 21 | Visschedijk et al (2004) |
| PM2.5 | 9 | g/GJ | 5.4 | 12.6 | Visschedijk et al (2004) |
| *BC* | *5.6* | *% of PM2.5* | *0.22* | *8.69* | *See Note* |
| Pb | 4.6 | mg/GJ | 0.9 | 23 | US EPA (1998), chapter 1.3 |
| Cd | 1.2 | mg/GJ | 0.24 | 6 | US EPA (1998), chapter 1.3 |
| Hg | 0.3 | mg/GJ | 0.03 | 0.6 | US EPA (1998), chapter 1.3 |
| As | 3.98 | mg/GJ | 0.796 | 19.9 | US EPA (1998), chapter 1.3 |
| Cr | 14.8 | mg/GJ | 2.96 | 74 | API (1998, 2002) |
| Cu | 11.9 | mg/GJ | 2.38 | 59.5 | API (1998, 2002) |
| Ni | 773 | mg/GJ | 647 | 900 | Concawe Report 9/16 |
| *Se* | *2.1* | mg/GJ | *0.40* | *10.5* | *US EPA (1998), chapter 1.3* |
| Zn | 49.3 | mg/GJ | 9.86 | 247 | API (1998, 2002) |
| PCDD/F | 2.5 | ng I-TEQ/GJ | 1.25 | 3.75 | UNEP (2005); Heavy fuel fired power boilers |
| *Benzo(b)fluoranthene* | *3.7* | *µg/GJ* | *0.74* | *18.5* | *API (1998, 2002)* |

Note:

The factor for SOx assumes no SO2 abatement and is based on 1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter; 95 % confidence intervals calculated using range from Table C-1 in Appendix C.

The BC emission factor is derived as the average of the data found in Olmez et al. (1988), England et al. (2007) and the Speciate database (US EPA, 2011).

For benzo(a)pyrene, benzo(k)fluoranthene and indeno(1,2,3-cd)pyrene all measurements reported by API (1998) were below the detection limit. Using this the EFs would be 0.60, 0.20 and 1.3 µg/GJ respectively.

These PM factors represent filterable PM emissions.

Table 4‑5 Tier 2 emission factors for source category 1.A.1.b, process furnaces, using gas oil

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.b | Petroleum refining | | | |
| **Fuel** | Gas Oil | | | | |
| **SNAP (if applicable)** | 0103 | Petroleum refining plants | | | |
| **Technologies/Practices** | Process Furnaces, Heaters and Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, PCDD/F, Benzo(a)pyrene, *Benzo(b)fluoranthene,* Benzo(k)fluoranthene, Indeno(1,2,3-cd)pyrene, PCBs, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 65 | g/GJ | 32.5 | 97.5 | US EPA (1998), chapter 1.3 |
| CO | 16.2 | g/GJ | 5.4 | 50 | US EPA (1998), chapter 1.3 |
| NMVOC | 0.65 | g/GJ | 0.22 | 1.95 | US EPA (1998), chapter 1.3 |
| Sox | 46.1 | g/GJ | 36.9 | 460 | See Note |
| TSP | 6.47 | g/GJ | 1.29 | 32.3 | US EPA (1998), chapter 1.3 |
| PM10 | 3.23 | g/GJ | 0.647 | 16.2 | US EPA (1998), chapter 1.3 |
| PM2.5 | 0.808 | g/GJ | 0.162 | 4.04 | US EPA (1998), chapter 1.3 |
| BC | 33.5 | % of PM2.5 | 28.9 | 38 | Hildemann et al., 1981 & Bond et al., 2006 |
| Pb | 4.07 | mg/GJ | 2.04 | 8.14 | US EPA (1998), chapter 1.3 |
| Cd | 1.36 | mg/GJ | 0.68 | 2.72 | US EPA (1998), chapter 1.3 |
| Hg | 1.36 | mg/GJ | 0.68 | 2.72 | US EPA (1998), chapter 1.3 |
| As | 1.81 | mg/GJ | 0.905 | 3.62 | US EPA (1998), chapter 1.3 |
| Cr | 1.36 | mg/GJ | 0.68 | 2.72 | US EPA (1998), chapter 1.3 |
| Cu | 2.72 | mg/GJ | 1.36 | 5.44 | US EPA (1998), chapter 1.3 |
| Ni | 1.36 | mg/GJ | 0.68 | 2.72 | US EPA (1998), chapter 1.3 |
| Se | 6.79 | mg/GJ | 0.68 | 67.9 | US EPA (1998), chapter 1.3 |
| Zn | 1.81 | mg/GJ | 0.905 | 3.62 | US EPA (1998), chapter 1.3 |

Note:

Based on 0.1 % mass sulphur content.

These PM factors represent filterable PM emissions only (excluding any condensable fraction).

Table 4‑6 Tier 2 emission factors for source category 1.A.1.b, process furnaces using natural gas

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.b | Petroleum refining | | | |
| **Fuel** | Natural Gas | | | | |
| **SNAP (if applicable)** | 0103 | Petroleum refining plants | | | |
| **Technologies/Practices** | Process Furnaces, Heaters and Boilers | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** | PAH, PCDD/F, PCBs, HCB | | | | |
| **Not estimated** | NH3, | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 63 | g/GJ | 31.5 | 84.4 | US EPA (1998), chapter 1.4 |
| CO | 39.3 | g/GJ | 23.6 | 55.1 | US EPA (1998), chapter 1.4 |
| NMVOC | 2.58 | g/GJ | 1.29 | 5.16 | US EPA (1998), chapter 1.4 |
| SOx | 0.281 | g/GJ | 0.169 | 0.393 | US EPA (1998), chapter 1.4 |
| TSP | 0.89 | g/GJ | 0.297 | 2.67 | US EPA (1998), chapter 1.4 |
| PM10 | 0.89 | g/GJ | 0.297 | 2.67 | US EPA (1998), chapter 1.4 |
| PM2.5 | 0.89 | g/GJ | 0.297 | 2.67 | US EPA (1998), chapter 1.4 |
| BC | 8.6 | % of PM2.5 | 4.3 | 17.2 | Wien et al., 2004 |
| Pb | 0.0015 | mg/GJ | 0.0005 | 0.0045 | Nielsen et al., 2012 |
| Cd | 0.00025 | mg/GJ | 0.00008 | 0.00075 | Nielsen et al., 2012 |
| Hg | 0.1 | mg/GJ | 0.01 | 1 | Nielsen et al., 2010 |
| As | 0.12 | mg/GJ | 0.04 | 0.36 | Nielsen et al., 2012 |
| Cr | 0.00076 | mg/GJ | 0.00025 | 0.00228 | Nielsen et al., 2012 |
| Cu | 0.000076 | mg/GJ | 0.000025 | 0.000228 | Nielsen et al., 2012 |
| Ni | 0.00051 | mg/GJ | 0.00017 | 0.00153 | Nielsen et al., 2012 |
| Se | 0.0112 | mg/GJ | 0.00375 | 0.0337 | US EPA (1998), chapter 1.4 |
| Zn | 0.0015 | mg/GJ | 0.0005 | 0.0045 | Nielsen et al., 2012 |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |

Note:

The factor for SOx is based on approximately 0.01 g/m3 mass sulphur content. SO2 emission factor can also be calculated using EF calculation from subsection 3.4.2.2 of the present chapter.

It must be noted that the Hg content (and other heavy metals) of natural gas varies between gas fields. However, the differences after natural gas processing is thought to be of minor importance. The US EPA (1998) provides an emission factor of 0.1 mg/GJ. It is encouraged that countries obtain country specific data for the natural gas based on the origin.

These PM factors represent filterable PM emissions only (excluding any condensable fraction).

Table 4‑7 Tier 2 emission factors for source category 1.A.1.b, stationary engines using natural gas

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.b | Petroleum refining | | | |
| **Fuel** | Natural Gas | | | | |
| **SNAP (if applicable)** | 010305 | Petroleum refining - Stationary engines | | | |
| **Technologies/Practices** | **4-stroke lean burn gas engines** | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** | PAH, PCDD/F, PCBs, HCB | | | | |
| **Not estimated** | NH3, | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 405 | g/GJ | 200 | 810 | US EPA (2000), chapter 3.2; |
| CO | 266 | g/GJ | 130 | 530 | US EPA (2000), chapter 3.2; |
| NMVOC | 56 | g/GJ | 30 | 110 | US EPA (2000), chapter 3.2; |
| SOx | 0.281 | g/GJ | 0.169 | 0.393 | US EPA (2000), chapter 3.2; |
| TSP | 0.037 | g/GJ | 0.003 | 0.37 | US EPA (2000), chapter 3.2; |
| PM10 | 0.037 | g/GJ | 0.003 | 0.37 | US EPA (2000), chapter 3.2; |
| PM2.5 | 0.037 | g/GJ | 0.003 | 0.37 | US EPA (2000), chapter 3.2; |
| BC | 2.5 | % of PM2.5 | 1 | 6.3 | See Note |
| Pb | 0.04 | mg/GJ | 0.013 | 0.12 | Nielsen et al., 2010 |
| Cd | 0.003 | mg/GJ | 0.001 | 0.009 | Nielsen et al., 2010 |
| Hg | 0.1 | mg/GJ | 0.03 | 0.3 | Nielsen et al., 2010 |
| As | 0.05 | mg/GJ | 0.017 | 0.15 | Nielsen et al., 2010 |
| Cr | 0.05 | mg/GJ | 0.017 | 0.15 | Nielsen et al., 2010 |
| Cu | 0.01 | mg/GJ | 0.003 | 0.03 | Nielsen et al., 2010 |
| Ni | 0.05 | mg/GJ | 0.017 | 0.15 | Nielsen et al., 2010 |
| Se | 0.2 | mg/GJ | 0.07 | 0.6 | Nielsen et al., 2010 |
| Zn | 2.91 | mg/GJ | 0.97 | 8.73 | Nielsen et al., 2010 |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |
|  |  |  |  |  |  |

Notes:

It must be noted that the Hg content (and other heavy metals) of natural gas varies between gas fields. The US EPA (1998) provides an emission factor of 0.1 mg/GJ. It is encouraged that countries obtain country specific data for the natural gas based on the origin. Also the amount of lubricants oxidised during use can significantly influence the emission factors of heavy metals.

The factor for SOx is based on approximately 0.01 gm3 mass sulphur content. SO2 emission factor can also be calculated using EF calculation from subsection 3.4.2.2 of the present chapter.

The BC emission factor is the average of the data available in England et al. (2004), Wien et al. (2004) and the Speciate database (US EPA, 2011).

These PM factors represent filterable PM emissions only (excluding any condensable fraction).

Table 4‑8 Tier 2 emission factors for source category 1.A.1.b, diesel engines using gas oil

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.b | Petroleum refining | | | |
| **Fuel** | Gas Oil | | | | |
| **SNAP (if applicable)** | 010305 | Petroleum refining - Stationary engines | | | |
| **Technologies/Practices** | Reciprocating Engines (compression injection) | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** |  | | | | |
| **Not estimated** | NH3, PCDD/F, PCBs, HCB | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 942 | g/GJ | 500 | 1380 | Nielsen et al., 2010 |
| CO | 130 | g/GJ | 30 | 230 | Nielsen et al., 2010 |
| NMVOC | 37.1 | g/GJ | 18.5 | 55.6 | US EPA (1996), chapter 3.4 |
| SOx | 46.1 | g/GJ | 4.61 | 461 | See Note |
| TSP | 28.1 | g/GJ | 14.1 | 56.2 | US EPA (1996), chapter 3.4 |
| PM10 | 22.4 | g/GJ | 11.2 | 44.8 | US EPA (1996), chapter 3.4 |
| PM2.5 | 21.7 | g/GJ | 10.8 | 43.4 | US EPA (1996), chapter 3.4 |
| BC | 78 | % of PM2.5 | 63 | 93 | Hernandez et al., 2004 |
| Pb | 4.07 | mg/GJ | 0.41 | 40.7 | US EPA (1998), chapter 1.3 |
| Cd | 1.36 | mg/GJ | 0.14 | 13.6 | US EPA (1998), chapter 1.3 |
| Hg | 1.36 | mg/GJ | 0.14 | 13.6 | US EPA (1998), chapter 1.3 |
| As | 1.81 | mg/GJ | 0.18 | 18.1 | US EPA (1998), chapter 1.3 |
| Cr | 1.36 | mg/GJ | 0.14 | 13.6 | US EPA (1998), chapter 1.3 |
| Cu | 2.72 | mg/GJ | 0.27 | 27.1 | US EPA (1998), chapter 1.3 |
| Ni | 1.36 | mg/GJ | 0.14 | 13.6 | US EPA (1998), chapter 1.3 |
| Se | 6.79 | mg/GJ | 0.68 | 67.9 | US EPA (1998), chapter 1.3 |
| Zn | 1.81 | mg/GJ | 0.18 | 18.1 | US EPA (1998), chapter 1.3 |
| PCDD/F | 0.99 | ng I-TEQ/GJ | 0.1 | 10 | Nielsen et al., 2010 |
| HCB | 0.22 | µg/GJ | 0.022 | 2.2 | Nielsen et al., 2010 |
| PCBs | 0.13 | ng I-TEQ/GJ | 0.013 | 1.3 | Nielsen et al., 2010 |
| Benzo(a)pyrene | 0.11 | mg/GJ | 0.04 | 0.33 | API, 1998 |
| Benzo(b)fluoranthene | 0.49 | mg/GJ | 0.16 | 1.47 | API, 1998 |
| Benzo(k)fluoranthene | 0.096 | mg/GJ | 0.032 | 0.288 | API, 1998 |
| Indeno(1,2,3-cd)pyrene | 0.18 | mg/GJ | 0.06 | 0.54 | API, 1998 |

Notes:

The factor for SOx assumes no SO2 abatement and is based on 0.1 % mass sulphur content using EF calculation from subsection 3.4.2.2 of the present chapter.

Emission factors for metals are based on factors for oil combustion in boilers.

These PM factors represent filterable PM emissions only (excluding any condensable fraction)

#### Activity data

Information on the refinery production suitable for estimating emissions using the simpler estimation methodology (Tier 1 and 2) may be available from national statistics agencies or the International Energy Agency (IEA).

Further guidance is provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, volume 2 on Stationary Combustion   
[www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2\_Volume2/V2\_2\_Ch2\_Stationary\_Combustion.pdf](https://www.concawe.eu//uploads/Modules/Publications/rpt_15-3.pdf)

For a Tier 2 approach these data need to be stratified according to technologies applied. Typical sources for this data might be industrial or regulatory organisations within the country or from specific questionnaires to the individual refineries.

### Tier 3 use of facility-specific data

#### Algorithm

Where facility-level emission data of sufficient quality (see Chapter 3, Data collection, in part A) are available, it is good practice to use these data. There are two possibilities:

* the facility reports cover all refinery processes in the country;
* facility-level emission reports are not available for all the refinery processes.

If facility-level data are available covering all activities in the country, the implied emission factors (reported emissions divided by the national fuel use) should be compared with the default emission factor values or technology-specific emission factors. If the implied emission factors are outside the 95 % confidence intervals for the values given, it is good practice to explain the reasons for this in the inventory report.

Depending on the specific national circumstances and the coverage of the facility-level reports as compared to the total combustion activity, the emission factor (EF) in this equation should be chosen from the following possibilities, in decreasing order of preference:

* technology-specific emission factors, based on knowledge of the types of technologies implemented at the facilities where facility-level emission reports are not available;
* the implied emission factor derived from the available emission reports:

 (7)

* the default Tier 1 emission factor. This option should only be chosen if the facility-level emission reports cover more than 90 % of the total national production.

#### Tier 3 emission modelling and use of facility data

Refinery installations are major facilities and emission data for individual plants could be available through a pollutant release and transfer registry (PRTR) or another national emission reporting scheme, but possibly not for all pollutants. When the quality of such data is assured by a well- developed QA/QC system, it is good practice to use such data. Guidance on estimating refinery emissions has been published by the industry sector [Concawe, 2015]. If extrapolation is needed to cover all activity in the country, either the implied emission factors for the facilities that did report, or the emission factors as provided above, could be used (see subsection 3.4.3.2 of the present chapter).

#### Activity data

Since PRTR generally do not report activity data, such data in relation to the reported facility-level emissions are sometimes difficult to find. A possible source of facility-level activity might be the registries of emission trading systems.

In many countries national statistics offices collect production data on facility level, but these are in many cases confidential. However, in several countries, national statistics offices are part of the national emission inventory systems and the extrapolation, if needed, could be performed at the statistics office, ensuring that confidentiality of production data is maintained.

# 1.A.1.c Manufacture of solid fuels and other energy industries

## Techniques

Coke manufacture is mainly associated with iron and steel manufacture and details of technologies used in this activity can be found within the Best Available Techniques Reference Note (BREF) for Iron and Steel production [EIPPCB, 2013] and within the USEPA guidance.

Coke manufacture is a batch process with production occurring in a coke oven which is a battery of ovens. Coal is heated in a non-oxidising atmosphere (pyrolysis). The volatile components are driven off to leave coke which is then pushed at high temperature from the oven into a rail car and taken to a quench tower to stop oxidation in air. Heating is provided by combustion of a portion of the evolved gases, following treatment to remove ammonia, hydrogen sulphide, tars and condensable organic material. Coke manufacture with by-product recovery includes process units to recover condensed organic material and other by-products. By-products are burnt in coke ovens which do not have by-product recovery.

## Emissions

Note that the inventory methodologies for Greenhouse gas emissions (carbon dioxide, methame and nitrous oxide) are not included – refer to IPCC guidance [IPCC, 2006].

##### Sulphur oxides

Emissions arise from combustion of coke oven gas (COG). Gas is treated to removed H2S but residual H2S is oxidised to form SO2.

##### Nitrogen oxides

Emissions of nitrogen oxides (nitric oxide and nitrogen dioxide — NOx) arise primarily from combustion of COG.

##### Non-methane volatile organic compounds (NMVOC)

Emissions of non-methane volatile organic compounds (NMVOC) can result from combustion activities and process discharges such as vents and blowdown systems. However, many emission sources tend to be fugitive releases.

##### Carbon monoxide (CO)

Emissions arise from combustion activities and fugitive release of COG.

##### Particulate matter

Particulate matter (PM) emissions arise from combustion activities on the coke oven and materials handling.

## Controls

Details- of relevant abatement technologies are described in the BREF note for iron and steel production (http://eippcb.jrc.ec.europa.eu/reference/). Control of SO2 emission is by removal of H2S and other sulphurous material from the fuel gas.

## Methods

### Choice of method

Figure 5‑1 presents the procedure to select the methods for estimating process emissions from combustion in energy and transformation industries. The basic idea is:

* if detailed information is available, use it;
* if the source category is a key source, a Tier 2 or better method must be applied and detailed input data must be collected. The decision tree directs the user in such cases to the Tier 2 method, since it is expected that it is easier to obtain the necessary input data for this approach than to collect facility-level data needed for a Tier 3 estimate;
* the alternative of applying a Tier 3 method using detailed process modelling is not explicitly included in this decision tree. However, detailed modelling will always be done at facility level and results of such modelling could be seen as ‘Facility data’ in the decision tree.

Figure 5‑1 Decision tree for combustion in manufacture of solid fuels



### Tier 1 default approach

#### Algorithm

The Tier 1 approach for process emissions from combustion uses the general equation:

 (1)

where

*Epollutant* = annual emission of pollutant

*EFpollutant* = emission factor of pollutant

*ARfuel consumption* = activity rate by coal consumption, coke or iron production

This equation is applied at the national level, using annual national coal use (disaggregated by industrial sector). Information on fuel consumption suitable for estimating emissions using the simpler estimation methodology is widely available from UN statistical yearbooks or national statistics.

The Tier 1 emission factors assume an average or typical technology and abatement implementation.

In cases where specific abatement techniques are to be taken into account a Tier 1 method is not applicable and a Tier 2 or Tier 3 approach must be used.

#### Default emission factors

The Tier 1 default emission factors for process and combustion emissions are given in Table 5‑1 and have been derived from emission factors provided in USEPA guidance. The factors are based on coal use expressed in terms of net energy content. The factors include combustion and process emissions from coke batteries, including combustion stacks and preheater. Emissions from soaking, decarbonisation, charging, door and lid leaks, off-take leaks, quenching and pushing are included in Chapter 1.B.1.b Fugitive emissions from solid fuels: solid fuel transformation. In the absence of detail on relative use of coke oven types or abatement technology, which will be different for each country, the proposed factors represent a mean for the range of technologies in use with the 95 % figures a measure of the range of emissions in the sector.

Table 5‑1 Tier 1 emission factors for source category 1.A.1.c

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 1 default emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.c | Manufacture of solid fuels and other energy industries | | | |
| **Fuel** | Coal | | | | |
| **Not applicable** | PCBs, HCB | | | | |
| **Not estimated** | NH3,BC, | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 21 | g/GJ | 11.5 | 42 | See note |
| CO | 6 | g/GJ | 3 | 12 | See note |
| NMVOC | 0.8 | g/GJ | 0.08 | 8.1 | See note |
| SOx | 91 | g/GJ | 60 | 120 | See note |
| TSP | 82 | g/GJ | 40 | 160 | See note |
| PM10 | 79 | g/GJ | 40 | 160 | See note |
| PM2.5 | 55 | g/GJ | 28 | 110 | See note |
| Pb | 28 | mg/GJ | 5.92 | 145 | See note |
| Cd | 1.6 | mg/GJ | 0.32 | 9 | See note |
| Hg | 30 | mg/GJ | 6 | 150 | See note |
| As | 11 | mg/GJ | 2.2 | 55 | See note |
| Cr | 5.7 | mg/GJ | 1.18 | 29.5 | See note |
| Cu | 25 | mg/GJ | 5 | 125 | See note |
| Ni | 5.2 | mg/GJ | 1.1 | 26 | See note |
| Se | 2.9 | mg/GJ | 0.6 | 15 | See note |
| Zn | 46 | mg/GJ | 9.4 | 235 | See note |
| PCDD/F | 26 | ng I-TEQ/GJ | 5.2 | 130 | See note |
| Benzo(a)pyrene | 0.29 | mg/GJ | 0.066 | 1.65 | See note |
| Benzo(b)fluoranthene | 0.003 | mg/GJ | 0.0006 | 0.015 | See note |
| Benzo(k)fluoranthene | 0.001 | mg/GJ | 0.0002 | 0.005 | See note |
| Indeno(1,2,3-cd)pyrene | 0.001 | mg/GJ | 0.0002 | 0.005 | See note |

Note:

The tier 1 emission factors are calculated as an average of the tier 2 emission factors. The tier 2 emission factors have been converted using a NCV of 28.2 GJ/Mg.

The basis of the TSP, PM10 and PM2.5 emission factors could not be determined in the reference.

#### Tier 1 Activity Data

Information on the use of energy, suitable for estimating emissions using the Tier 1 simpler estimation methodology, is available from national statistics agencies or the International Energy Agency (IEA).

Further guidance is provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, volume 2 on Stationary Combustion   
www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2\_Volume2/V2\_2\_Ch2\_Stationary\_Combustion.pdf

The activity rate and the emission factor have to be determined on the same level of aggregation depending on the availability of data. The activity statistic should be determined within the considered country or region by using adequate statistics. The activity should refer to the energy input of the emission sources considered (net or inferior fuel consumption in [GJ]).

### Tier 2 approach

For a Tier 2 approach the emission factors are presented in terms of coal use with two technologies. Note that emission factors can be converted to g/Mg coke produced by applying a conversion of 1 285 kg coal/Mg coke (from the Iron and Steel BREF range of 1220–1 350 kg coal/Mg coke).

The factors represent combustion and process emissions from coke batteries, including combustion stacks and preheater. Emissions from soaking, decarbonisation, charging, door and lid leaks, off-take leaks, quenching and pushing are included in Chapter 1.B.1.b Fugitive emissions from solid fuels: solid fuel transformation.

Table  5‑2 Tier 2 default emission factors for source category 1.A.1.c, coke manufacture with by-product recovery

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.c | Manufacture of solid fuels and other energy industries | | | |
| **Fuel** | Coal | | | | |
| **SNAP (if applicable)** | 0104 | Solid fuel transformation plants | | | |
| **Technologies/Practices** | Coke oven (byproduct recovery) | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** | PCB, Hg | | | | |
| **Not estimated** | NH3, Hg | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 820 | g/Mg Coal | 530 | 1200 | US EPA (2008), chapter 12.2 |
| CO | 340 | g/Mg Coal | 170 | 680 | US EPA (2008), chapter 12.2 |
| NMVOC | 47 | g/Mg Coal | 24 | 94 | US EPA (2008), chapter 12.2 |
| SOx | 420 | g/Mg Coal | 210 | 840 | US EPA (2008), chapter 12.2 |
| TSP | 1914 | g/Mg Coal | 955 | 3830 | US EPA (2008), chapter 12.2 |
| PM10 | 1864 | g/Mg Coal | 932 | 3728 | US EPA (2008), chapter 12.2 |
| PM2.5 | 1176 | g/Mg Coal | 588 | 2352 | US EPA (2008), chapter 12.2 |
| BC | 48 | % of PM2.5 | 5 | 95 | Bond et al. (2004) |
| Pb | 2.2 | mg/Mg Coal | 1.1 | 4.4 | US EPA (2008), chapter 12.2 |
| Cd | 0.1 | mg/Mg Coal | 0.05 | 0.2 | US EPA (2008), chapter 12.2 |
| As | 1.6 | mg/Mg Coal | 0.8 | 3.2 | US EPA (2008), chapter 12.2 |
| Cr | 3.6 | mg/Mg Coal | 1.8 | 7.2 | US EPA (2008), chapter 12.2 |
| Cu | 1.7 | mg/Mg Coal | 0.85 | 3.4 | US EPA (2008), chapter 12.2 |
| Ni | 0.9 | mg/Mg Coal | 0.45 | 1.8 | US EPA (2008), chapter 12.2 |
| Se | 1.8 | mg/Mg Coal | 0.9 | 3.6 | US EPA (2008), chapter 12.2 |
| Zn | 7.6 | mg/Mg Coal | 3.8 | 15.2 | US EPA (2008), chapter 12.2 |
| PCDD/F | 738 | ng I-TEQ/Mg Coal | 234 | 2335 | UNEP (2005) |
| Benzo(a)pyrene | 8.2 | mg/Mg Coal | 1.64 | 41 | US EPA (2008), chapter 12.2 |
| Benzo(b)fluoranthene | 0.1 | mg/Mg Coal | 0.02 | 0.5 | US EPA (2008), chapter 12.2 |
| Benzo(k)fluoranthene | 0.03 | mg/Mg Coal | 0.006 | 0.15 | US EPA (2008), chapter 12.2 |
| Indeno(1,2,3-cd)pyrene | 0.02 | mg/Mg Coal | 0.004 | 0.1 | US EPA (2008), chapter 12.2 |

Note:The basis of the TSP, PM10 and PM2.5 emission factors could not be determined in the reference (emission factors for filterable and condensable PM are provided for a number of process activities but it is unclear which have been incorporated in the Tier 2 emission factors).

Table 5‑3 Tier 2 default emission factors for source category 1.A.1.c, coke manufacture without by-product recovery

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Tier 2 emission factors** | | | | | |
|  | Code | Name | | | |
| **NFR Source Category** | 1.A.1.c | Manufacture of solid fuels and other energy industries | | | |
| **Fuel** | Coal | | | | |
| **SNAP (if applicable)** | 0104 | Solid fuel transformation plants | | | |
| **Technologies/Practices** | Coke oven (without byproduct recovery) | | | | |
| **Region or regional conditions** | NA | | | | |
| **Abatement technologies** | NA | | | | |
| **Not applicable** | PCBs, HCB | | | | |
| **Not estimated** | NMVOC, NH3, Benzo(b)fluoranthene, Benzo(k)fluoranthene, Indeno(1,2,3-cd)pyrene | | | | |
| **Pollutant** | **Value** | **Unit** | **95% confidence interval** | | **Reference** |
| **Lower** | **Upper** |
| NOx | 360 | g/Mg Coal | 250 | 590 | US EPA (2008), chapter 12.2 |
| CO | 25 | g/Mg Coal | 12.5 | 50 | US EPA (2008), chapter 12.2 |
| SOx | 4700 | g/Mg Coal | 2350 | 9200 | US EPA (2008), chapter 12.2 |
| TSP | 2700 | g/Mg Coal | 1350 | 5400 | US EPA (2008), chapter 12.2 |
| PM10 | 2618 | g/Mg Coal | 1309 | 5236 | US EPA (2008), chapter 12.2 |
| PM2.5 | 1913 | g/Mg Coal | 957 | 3826 | US EPA (2008), chapter 12.2 |
| BC | 48 | % of PM2.5 | 5 | 95 | Bond et al. (2004) |
| Pb | 1600 | mg/Mg Coal | 800 | 3200 | US EPA (2008), chapter 12.2 |
| Cd | 90 | mg/Mg Coal | 45 | 180 | US EPA (2008), chapter 12.2 |
| Hg | 1700 | mg/Mg Coal | 850 | 3400 | US EPA (2008), chapter 12.2 |
| As | 630 | mg/Mg Coal | 315 | 1260 | US EPA (2008), chapter 12.2 |
| Cr | 320 | mg/Mg Coal | 160 | 640 | US EPA (2008), chapter 12.2 |
| Cu | 1400 | mg/Mg Coal | 700 | 2800 | US EPA (2008), chapter 12.2 |
| Ni | 290 | mg/Mg Coal | 145 | 580 | US EPA (2008), chapter 12.2 |
| Se | 160 | mg/Mg Coal | 80 | 320 | US EPA (2008), chapter 12.2 |
| Zn | 2600 | mg/Mg Coal | 1300 | 5200 | US EPA (2008), chapter 12.2 |
| PCDD/F | 738 | ng I-TEQ/Mg Coal | 234 | 2335 | UNEP (2005) |
| Benzo(a)pyrene | 0.5 | mg/Mg Coal | 0.1 | 2.5 | US EPA (2008), chapter 12.2 |

Note:

The basis of the TSP, PM10 and PM2.5 emission factors could not be determined in the reference (emission factors for filterable and condensable PM are provided for a number of process activities but it is unclear which have been incorporated in the Tier 2 emission factors).

### Tier 3 use of facility-specific data

#### Algorithm

Where facility-level emission data of sufficient quality (see Chapter 3, Data collection, in part A) are available, it is good practice to use these data. There are two possibilities:

* the facility reports cover all relevant combustion processes in the country;
* facility-level emission reports are not available for all relevant combustion processes in the country.

If facility-level data are available covering all activities in the country, the implied emission factors (reported emissions divided by the national fuel use) should be compared with the default emission factor values or technology-specific emission factors. If the implied emission factors are outside the 95 % confidence intervals for the values given, it is good practice to explain the reasons for this in the inventory report.

Depending on the specific national circumstances and the coverage of the facility-level reports as compared to the total combustion activity, the emission factor (EF) in this equation should be chosen from the following possibilities, in decreasing order of preference:

* technology-specific emission factors, based on knowledge of the types of technologies implemented at the facilities where facility-level emission reports are not available;
* the implied emission factor derived from the available emission reports:

 (7)

* the default Tier 1 emission factor. This option should only be chosen if the facility-level emission reports cover more than 90 % of the total national production.

#### Tier 3: Use of facility data

Many coke ovens are (or are part of) major facilities, and emission data for individual plants might be available through a pollutant release and transfer registry (PRTR) or another national emission reporting scheme. When the quality of such data is assured by a well developed QA/QC system and the emission reports have been verified by an independent auditing scheme, it is good practice to use such data. If extrapolation is needed to cover all activity in the country either the implied emission factors for the facilities that did report, or the emission factors as provided above could be used (see subsection 3.4.3.2 of the present chapter).

#### Activity data

Since PRTR generally do not report activity data, such data in relation to the reported facility-level emissions are sometimes difficult to find. A possible source of facility-level activity might be the registries of emission trading systems.

In many countries national statistics offices collect production data on facility level, but these are in many cases confidential. However, in several countries, national statistics offices are part of the national emission inventory systems and the extrapolation, if needed, could be performed at the statistics office, ensuring that confidentiality of production data is maintained.

# Data quality

## Completeness

No specific issues, but the separation of combustion emissions from other emissions associated with the activities may potentially lead to exclusion of emissions.

## Avoiding double counting with other sectors

In cases where it is possible to split the emissions, it is good practice to do so. However, care must be taken that the emissions are not double counted (for example between combustion and process emissions).

## Verification

### Best Available Technique (BAT) emission factors

Table  6‑1 BAT-based emission factors for source category 1.A.1.a

| **Pollutant** | **Fuel type [1]** | **New or existing plant [2]** | **Boiler size or technology,** | **Reference O2 content,** | **AEL concentration range, mg.m-3 at STP (0ºC, 101.3 kPa) dry at reference O2 content** | | **Emission factor,**  **g·GJ-1**  **(net thermal input)** | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **MWth** | **%v/v dry** | **Low** | **High** | **Low** | **High** |
| TSP | coal | new | 50-100 | 6 | 5 | 20 | 1.8 | 7.2 |
|  | coal | new | 100-300 | 6 | 5 | 20 | 1.8 | 7.2 |
|  | coal | new | > 300 | 6 | 5 | 20 | 1.8 | 7.2 |
|  | coal | existing | 50-100 | 6 | 5 | 30 | 1.8 | 10.9 |
|  | coal | existing | 100-300 | 6 | 5 | 30 | 1.8 | 10.9 |
|  | coal | existing | > 300 | 6 | 5 | 30 | 1.8 | 10.9 |
|  | wood | new | 50-100 | 6 | 5 | 20 | 1.9 | 7.7 |
|  | wood | new | 100-300 | 6 | 5 | 20 | 1.9 | 7.7 |
|  | wood | new | > 300 | 6 | 5 | 20 | 1.9 | 7.7 |
|  | wood | existing | 50-100 | 6 | 5 | 20 | 1.9 | 7.7 |
|  | wood | existing | 100-300 | 6 | 5 | 20 | 1.9 | 7.7 |
|  | wood | existing | > 300 | 6 | 5 | 20 | 1.9 | 7.7 |
|  | oil | new | 50-100 | 3 | 5 | 20 | 1.4 | 5.7 |
|  | oil | new | 100-300 | 3 | 5 | 20 | 1.4 | 5.7 |
|  | oil | new | > 300 | 3 | 5 | 10 | 1.4 | 2.8 |
|  | oil | existing | 50-100 | 3 | 5 | 30 | 1.4 | 8.5 |
|  | oil | existing | 100-300 | 3 | 5 | 25 | 1.4 | 7.1 |
|  | oil | existing | > 300 | 3 | 5 | 20 | 1.4 | 5.7 |
|  |  |  |  |  |  |  |  |  |
|  | gas | new | GT | 15 | 5 |  | 4.3 |  |
|  | gas | existing | GT | 15 | 5 |  | 4.3 |  |
|  |  |  |  |  |  |  |  |  |
| NOx | coal | new | 50-100 | 6 | 90 | 300 | 32.6 | 108.7 |
|  | coal | new | 100-300 | 6 | 90 | 200 | 32.6 | 72.5 |
|  | coal | new | > 300 | 6 | 50 | 150 | 18.1 | 54.3 |
|  | coal | existing | 50-100 | 6 | 90 | 300 | 32.6 | 108.7 |
|  | coal | existing | 100-300 | 6 | 90 | 200 | 32.6 | 72.5 |
|  | coal | existing | > 300 | 6 | 50 | 200 | 18.1 | 72.5 |
|  | wood | new | 50-100 | 6 | 150 | 250 | 57.9 | 96.4 |
|  | wood | new | 100-300 | 6 | 150 | 200 | 57.9 | 77.1 |
|  | wood | new | > 300 | 6 | 50 | 150 | 19.3 | 57.9 |
|  | wood | existing | 50-100 | 6 | 150 | 300 | 57.9 | 115.7 |
|  | wood | existing | 100-300 | 6 | 150 | 250 | 57.9 | 96.4 |
|  | wood | existing | > 300 | 6 | 50 | 200 | 19.3 | 77.1 |
|  | oil | new | 50-100 | 3 | 150 | 300 | 42.4 | 84.9 |
|  | oil | new | 100-300 | 3 | 50 | 150 | 14.1 | 42.4 |
|  | oil | new | > 300 | 3 | 50 | 100 | 14.1 | 28.3 |
|  | oil | existing | 50-100 | 3 | 150 | 450 | 42.4 | 127.3 |
|  | oil | existing | 100-300 | 3 | 50 | 200 | 14.1 | 56.6 |
|  | oil | existing | > 300 | 3 | 50 | 150 | 14.1 | 42.4 |
|  | gas | new | > 50 | 3 | 50 | 100 | 14.2 | 28.3 |
|  | gas | existing | > 50 | 3 | 50 | 100 | 14.2 | 28.3 |
|  |  |  |  |  |  |  |  |  |
|  | gas | new | GT | 15 | 20 | 50 | 17.2 | 43.0 |
|  | gas | existing | GT | 15 | 20 | 90 | 17.2 | 77.3 |
|  |  |  |  |  |  |  |  |  |
|  | gas | new | Gas engine | 15 | 20 | 75 | 17.2 | 64.4 |
|  | gas | existing | Gas engine | 15 | 20 | 100 | 17.2 | 85.9 |
|  |  |  |  |  |  |  |  |  |
| SO2 | coal | new | 50-100 | 6 | 150 | 400 | 54.3 | 144.9 |
|  | coal | new | 100-300 | 6 | 100 | 200 | 36.2 | 72.5 |
|  | coal | new | > 300 | 6 | 20 | 200 | 7.2 | 72.5 |
|  | coal | existing | 50-100 | 6 | 150 | 400 | 54.3 | 144.9 |
|  | coal | existing | 100-300 | 6 | 100 | 250 | 36.2 | 90.6 |
|  | coal | existing | > 300 | 6 | 20 | 200 | 7.2 | 72.5 |
|  | wood | new | 50-100 | 6 | 200 | 300 | 77.1 | 115.7 |
|  | wood | new | 100-300 | 6 | 150 | 300 | 57.9 | 115.7 |
|  | wood | new | > 300 | 6 | 50 | 200 | 19.3 | 77.1 |
|  | wood | existing | 50-100 | 6 | 200 | 300 | 77.1 | 115.7 |
|  | wood | existing | 100-300 | 6 | 150 | 300 | 57.9 | 115.7 |
|  | wood | existing | > 300 | 6 | 50 | 200 | 19.3 | 77.1 |
|  | oil | new | 50-100 | 3 | 100 | 350 | 28.3 | 99.0 |
|  | oil | new | 100-300 | 3 | 100 | 200 | 28.3 | 56.6 |
|  | oil | new | > 300 | 3 | 50 | 150 | 14.1 | 42.4 |
|  | oil | existing | 50-100 | 3 | 100 | 350 | 28.3 | 99.0 |
|  | oil | existing | 100-300 | 3 | 100 | 250 | 28.3 | 70.7 |
|  | oil | existing | > 300 | 3 | 50 | 200 | 14.1 | 56.6 |
|  |  |  |  |  |  |  |  |  |
|  | gas | new | GT | 15 | 10 |  | 8.6 |  |
|  | gas | existing | GT | 15 | 10 |  | 8.6 |  |
|  |  |  |  |  |  |  |  |  |

Notes:

BAT-AELs are based on measurement of filterable PM.

Fuel is main classification only; limits may be for ‘solid fuels’ rather than coal or wood. Limits for gaseous fuels are for natural gas and may not be applicable to derived fuels.

New and existing plants are as defined in IED (2010).

The refinery BREF provides somewhat wide-ranging views on BAT for refinery emissions. Table 6‑2 provides a summary of the information presented. Note that, in the absence of detail about fuel gas composition, the emission factors were derived from the emission concentrations assuming natural gas. BAT emissions for energy processes are not presented.

Table 6‑2 BAT-based emission factors for refinery processes

| **Process unit** | **Pollutant** | **Average period** | **Reference O2 content,** | **AEL concentration range, mg.m-3 at STP (0ºC, 101.3 kPa) dry at reference O2 content** | | **Emission factor,**  **g·GJ-1**  **(net thermal input)** | |
| --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  | **%v/v dry** | **Low** | **High** | **Low** | **High** |
| Whole  Refinery | SO2 | daily | 3 | 60 | 850 | 17 | 241 |
| monthly | 3 | 100 | 1200 | 28 | 340 |
| yearly | 3 | 1000 | 1400 | 283 | 396 |
| NOx | daily | 3 | 70 | 200 | 20 | 57 |
| monthly | 3 | 100 | 450 | 28 | 127 |
| yearly | 3 | 200 | 500 | 57 | 142 |
| Cat cracker |  |  |  |  |  |  |  |
| CO boiler | CO | - | 3 | 50 | 100 | 14 | 28 |
| NOx | - | 3 | 100 | 500 | 28 | 142 |
| No CO boiler | CO | - | 3 | 50 | 100 | 14 | 28 |
| (O2 control) | NOx | - | 3 | 300 | 600 | 85 | 170 |
| SCR/SNCR | NOx | - | 3 | 40 | 150 | 11 | 43 |
| TSP | - | 3 | 10 | 50 | 3 | 14 |
| FGD/low S | SO2 | - | 3 | 10 | 350 | 3 | 99 |

The BAT document for coke ovens indicates that use of desulphurised coke oven gas and low-NOx techniques represent BAT in new or modern plant. Post-desulphurisation H2S levels of 500–1 000 mg.m-3 of fuel are indicated. However, further information is needed to calculate an emission factor; an estimated SO2 factor range of 60–120 g·GJ-1 has been calculated assuming a calorific value of 16.2 MJ.m-3[DUKES, 2007].

Estimated BAT emission factors (assuming natural gas as the fuel) for NOx are 140–220 g·GJ-1.

### Fuel sulphur content

For processes without SO2 abatement, the sulphur content of the fuel provides a means to calculate the SO2 emission factor.

EFSO2 = [S] x 20,000

CV

where:

EFSO2 is the SO2 emission factor g·GJ-1

[S] is the percent sulphur (w/w)

CV is the net/inferior calorific value GJ.tonne-1

2 is the ratio of the RMM of SO2 to sulphur

This equation can be extended to include a factor for retention of SO2 in ash.

Liquid fuels in the EC are subject to sulphur limits (EC SCOLF, 1999/2005) as summarised in Table 6‑3. The SO2 emission factors in Table 6‑3 have been calculated assuming 100 % conversion of fuel sulphur and applying UK net calorific values for fuel oils (DUKES, 2007).

Table 6‑3 Sulphur emission factors from oil sulphur limits

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Fuel oil** | **Implementation date** | **Maximum sulphur content** | **SO2 emission factor, g·GJ-1** | **Comment** |
| Heavy fuel oil | 1.1.2003 | 1 % | 485 | Assumes net CV of  41.2 GJ.tonne-1 |
| Gas oil | Pre 1.1.2008 | 0.2 % | 92 | Assumes net CV of |
|  | Post 1.1.2008 | 0.1 % | 46 | 43.4 GJ.tonne-1 |

### Other emission factors

The Industrial Emissions Directive, Gothenburg protocol, USEPA emission factor handbook and sector-specific emission factor guidance (Eurelectric and Concawe) provide additional means of assessing the validity of the default emission factors and factors from other sources to a national inventory.

Examples of emission factors derived from ELVs in the LCPD and Gothenburg protocol are provided in Appendix D. The USEPA emission factors can be found at [www.epa.gov/ttn/chief/ap42](http://www.epa.gov/ttn/chief/ap42/) .

### Derivation of emission factors from emission concentrations for combustion processes

A methodology to develop emission factors from emission concentrations (for example measurement reports and emission limit values) is provided in Appendix E.

## Developing a consistent time series and recalculation

The emissions of non-CO2 emissions from fuel combustion change with time as facilities are upgraded or replaced by less-polluting energy technology. The mix of technology used with each fuel will change with time and this has implications for the choice of emission factor. This is probably most relevant to the aggregated factors used in Tier 1 and Tier 2. Over time the Tier 1 emissions estimates become less relevant.

For Tier 3 using facility level data, it might occur that a different selection of facility level data is included in different years. This can lead to time series inconsistencies. Moreover, PRTR data are generally available for specific years only. Splicing such recent reported data under the European Pollutant Release and Transfer Registry (EPRTR)/European Pollutant Emission Register (EPER) with historical data could be used to get consistent time series. Splicing could be used for both the activity data and the country-specific emission factors.

Unexpected discontinuities in time series can occur when specific facilities come into operation or are closed in specific years. If this happens, it is good practice to clearly document such explanations in the inventory archives.

## Uncertainty assessment

### Emission factor uncertainties

The uncertainty is partly the result of how emission factors are developed and applied. The expanded statistical uncertainty is made up of: between plants variance, within plant (operating) variance, and uncertainties associated with the measurement methodology used and the aggregation of data.

Process measurements, from which emission factors are developed at individual facility level, are subject to both systematic and random errors in the determination of mass concentration, mass emission, size distribution, and analytical errors, etc.

In addition, bias may exist in emission factors arising from assumptions made about the abatement used on ‘typical’ industrial installations. For example, emission factors ‘age’, the factors widely used in the Guidebook and hence by many countries as default emission factors in their national inventories become out of date. Recent measurement work suggests that they may overestimate emissions from the industrial processes subject to more modern industrial emissions regulation. They may, however, still be fully representative for older plant, small plant, or for poorer fuels.

### Activity data uncertainties

The uncertainty in national fuel and production statistics can be difficult to establish, however; reporting procedures have generally been in place for many years. Recent developments in emission trading provide a ‘bottom-up’ and verified alternative to national statistics in some sectors.

The uncertainty for disaggregated sector-specific activity data can be high as such data may be collected infrequently or rely on assumptions which may vary substantially with time.

The inventory compiler needs to understand how sector-specific activity data have been derived.

## Inventory quality assurance/quality control QA/QC

Emissions from fuel combustion are largely associated with electricity production. It is good practice to check whether the electricity production data are consistent with the reported fuel use.

## Mapping

The facilities within 1.A.1 should be considered as point sources if plant-specific data are available. Otherwise national emissions should be disaggregated on the basis of plant capacity, employment or population statistics.

## Reporting and documentation

No specific issues.

# Glossary

| **Term** | **Definition** |
| --- | --- |
| Boiler | any technical apparatus, in which fuels are oxidised in order to generate steam. |
| Process heater or furnace | any technical apparatus, in which fuels are oxidised in order to generate heat for a process activity. |
| Coking coal (Nomenclature for Air Pollution of Fuels (NAPFUE) 101) | subcategory of hard coal with a quality that allows the production of a coke suitable for supporting a blast furnace charge (Meijer, 1995). |
| Co-generation plant | Simultaneous production of electricity and steam (or process heating). |
| Combined cycle gas turbine (CCGT) | gas turbine combined with a steam turbine. The boiler can also be fuelled separately. |
| Hard coal | refers to coal of a gross caloric value greater than 23 865 kJ/kg on an ash-free but moist basis and with a mean random reflectance ([[2]](#footnote-2)) of vitrinite of at least 0.6. Hard coal comprises the subcategories coking coal and steam coal ([[3]](#footnote-3)) [Meijer, 1995]. |
| Integrated coal gasification combined cycle gas turbine (IGCC) | gas turbine fuelled by gas, which is a product of a coal gasification process. |
| Lignite (NAPFUE 105) | non-agglomerating coals with a gross caloric value less than 17 435 kJ/kg and containing more than 31 % volatile matter on a dry mineral matter free basis. |
| Power plant | installation or facility for electricity generation. |
| Stationary engines | spark-ignition or compression-ignition engines (2- and 4-stroke). |
| Steam coal (NAPFUE 102) | subcategory of hard coal used for steam raising and space heating purposes. Steam coal includes all anthracite and bituminous coals not included under coking coal (Meijer, 1995). |
| Sub-bituminous coal  (NAPFUE 103) | non-agglomerating coals with a gross caloric value between 17 435 and 23 865 kJ/kg containing more than 31 % volatile matter on a dry mineral free matter basis (Meijer, 1995). |

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# Point of enquiry

Enquiries concerning this chapter should be directed to the relevant leader(s) of the Task Force on Emission Inventories and Projection’s expert panel on combustion and industry (TFEIP). Please refer to the TFEIP website ([www.tfeip-secretariat.org/](http://www.dmu.dk/Pub/FR786.pdf)) for the contact details of the current expert panel leaders.

# Summary of combustion plant and NFR codes

Table A1: Combustion plant and sector codes

|  | **Combustion plants as point and area sources** | | | | | | | | | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  | | | | | | | | | | |
| NFR  CODE | SNAP97  Codes | NOSE  CODE |  |  |  |  |  |  |  |  |  |
|  |  |  | Thermal capacity [MWth ] | Public power and cogeneration plants | District heating | Industrial combustion and specific sector | Commercial and institutional combustion | Residential combustion | Agriculture forestry and fishing | Gas turbines | Stationary engines |
| 1.A.1.a | 01 01 01 | 101.01 |  | x |  |  |  |  |  |  |  |
| 1.A.1.a | 01 02 01 | 101.01 |  |  | x |  |  |  |  |  |  |
| 1.A.1.b | 01 03 01 | 101.01 |  |  |  | x |  |  |  |  |  |
| 1.A.1.c | 01 04 01 | 101.01 | ≥ 300 |  |  | x |  |  |  |  |  |
| 1.A.1.c | 01 05 01 | 101.01 |  |  |  | x |  |  |  |  |  |
| 1.A.4.a | 02 01 01 | 101.01 |  |  |  |  | X |  |  |  |  |
| 1.A.2.a-f | 03 01 01 | 101.01 |  |  |  | x |  |  |  |  |  |
| 1.A.1.a | 01 01 02 | 101.02 |  | x |  |  |  |  |  |  |  |
| 1.A.1.a | 01 02 02 | 101.02 |  |  | x |  |  |  |  |  |  |
| 1.A.1.b | 01 03 02 | 101.02 |  |  |  | x |  |  |  |  |  |
| 1.A.1.c | 01 04 02 | 101.02 | ≥ 50 |  |  | x |  |  |  |  |  |
| 1.A.1.c | 01 05 02 | 101.02 | and |  |  | x |  |  |  |  |  |
| 1.A.4.a | 02 01 02 | 101.02 | < 300 |  |  |  | X |  |  |  |  |
| 1.A.4.b.i | 02 02 01 | 101.02 |  |  |  |  |  | x |  |  |  |
| 1.A.4.c.i | 02 03 01 | 101.02 |  |  |  |  |  |  | x |  |  |
| 1.A.2.a-f | 03 01 02 | 101.02 |  |  |  | x |  |  |  |  |  |
| 1.A.1.a | 01 01 03 | 101.03 |  | x |  |  |  |  |  |  |  |
| 1.A.1.a | 01 02 03 | 101.03 |  |  | x |  |  |  |  |  |  |
| 1.A.1.b | 01 03 03 | 101.03 |  |  |  | x |  |  |  |  |  |
| 1.A.1.c | 01 04 03 | 101.03 |  |  |  | x |  |  |  |  |  |
| 1.A.1.c | 01 05 03 | 101.03 | < 50 |  |  | x |  |  |  |  |  |
| 1.A.4.a | 02 01 03 | 101.03 |  |  |  |  | X |  |  |  |  |
| 1.A.4.b.i | 02 02 02 | 101.03 |  |  |  |  |  | x |  |  |  |
| 1.A.4.c.i | 02 03 02 | 101.03 |  |  |  |  |  |  | x |  |  |
| 1.A.2.a-f | 03 01 03 | 101.03 |  |  |  | x |  |  |  |  |  |
| 1.A.1.a | 01 01 04 | 101.04 |  |  |  |  |  |  |  | x |  |
| 1.A.1.a | 01 02 04 | 101.04 |  |  |  |  |  |  |  | x |  |
| 1.A.1.b | 01 03 04 | 101.04 |  |  |  |  |  |  |  | x |  |
| 1.A.1.c | 01 04 04 | 101.04 | not |  |  |  |  |  |  | x |  |
| 1.A.1.c | 01 05 04 | 101.04 | relevant |  |  |  |  |  |  | x |  |
| 1.A.4.a | 02 01 04 | 101.04 |  |  |  |  |  |  |  | x |  |
| 1.A.4.b.i | 02 02 03 | 101.04 |  |  |  |  |  |  |  | x |  |
| 1.A.4.c.i | 02 03 03 | 101.04 |  |  |  |  |  |  |  | x |  |
| 1.A.2.a-f | 03 01 04 | 101.04 |  |  |  |  |  |  |  | x |  |
| 1.A.1.a | 01 01 05 | 101.05 |  |  |  |  |  |  |  |  | x |
| 1.A.1.a | 01 02 05 | 101.05 |  |  |  |  |  |  |  |  | x |
| 1.A.1.b | 01 03 05 | 101.05 |  |  |  |  |  |  |  |  | x |
| 1.A.1.c | 01 04 05 | 101.05 | not |  |  |  |  |  |  |  | x |
| 1.A.1.c | 01 05 05 | 101.05 | relevant |  |  |  |  |  |  |  | x |
| 1.A.4.a | 02 01 05 | 101.05 |  |  |  |  |  |  |  |  | x |
| 1.A.4.b.i | 02 02 04 | 101.05 |  |  |  |  |  |  |  |  | x |
| 1.A.4.c.i | 02 03 04 | 101.05 |  |  |  |  |  |  |  |  | x |
| 1.A.2.a-f | 03 01 05 | 101.05 |  |  |  |  |  |  |  |  | x |

Note:

x = indicates relevant combination.

1. Further details on emissions and controls

Additional information taken from the 2006 Guidebook (Chapter B111) which may be relevant when assessing pollutants and controls. Note that the Large Combustion Plant BREF provides a more recent review of emissions and abatement technologies.

**Emissions**

The emissions are released through the stack. Fugitive emissions (from seals, etc.) can be neglected for combustion plants.

The emissions of sulphur oxides (SOx) are directly related to the sulphur content of the fuel, which for coal normally varies between 0.3 and 1.2 wt.-% (maf) (up to an extreme value of 4.5 wt.-%) and for fuel oil (including heavy fuel oil) from 0.3 up to 3.0 wt.-%.

Sulphur appears in coal as pyritic sulphur (FeS2), organic sulphur, sulphur salts and elemental sulphur. A major part of the sulphur in coal comes from pyritic and organic sulphur; both types are responsible for SOx formation.

For nitric oxide (NO, together with NO2 normally expressed as nitrogen oxides NOx), three different formation mechanisms are relevant:

* formation of ‘fuel-NO’ from the conversion of chemically-bound nitrogen in the fuel (NOfuel);
* formation of ‘thermal-NO’ from the fixation of atmospheric nitrogen coming from the combustion air (NOthermal);
* formation of ‘prompt-NO’.

In the temperature range considered (up to 1 700 °C) the formation of ‘prompt-NO’ can be neglected. The majority of NOx emissions from coal combustion (80 to more than 90 %) is formed from fuel nitrogen. Depending on combustion temperatures, the portion of thermal- NOx formed is lower than 20 %. The content of nitrogen in solid fuels varies:

* for hard coal between 0.2 and 3.5 wt.-% (maf);
* for lignite between 0.4 and 2.5 wt.-% (maf);
* for coke between 0.6 and 1.55 wt.-% (maf);
* for peat between 0.7 and 3.4 wt.-% (maf);
* for wood between 0.1 and 0.3 wt.-% (maf); and
* for waste between 0.3 and 1.4 wt.-% (maf).

The content of nitrogen in liquid fuels varies for heavy fuel oil between 0.1 and 0.8 wt.-%, and for fuel oil between 0.005 and 0.07 wt.-%. Natural gas contains no organically-bound nitrogen. The content of molecular nitrogen in natural gas has no influence on the formation of fuel-NO; only thermal-NO is formed.

Emissions of non-methane volatile organic compounds (NMVOC), e.g. olefins, ketones, aldehydes, result from incomplete combustion. Furthermore, unreacted fuel compounds such as methane (CH4) can be emitted. The relevance of NMVOC/CH4 emissions from boilers, which are often reported together as VOC, is very low for large-sized combustion plants.

VOC emissions tend to decrease as the plant size increases. Carbon monoxide (CO) appears always as an intermediate product of the combustion process and in particular under sub-stoichiometric combustion conditions.

The formation mechanisms of CO, thermal-NO and VOC are similarly influenced by combustion conditions.

Emissions of ammonia (NH3) are not caused by a combustion process; the emissions result from incomplete reaction of NH3 additive in the denitrification process (slip of ammonia in SCR and SNCR units).

Most of the heavy metals considered (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn, and V) are normally released as compounds (e.g. oxides, chlorides) in association with particulates. Only Hg and Se are at least partly present in the vapour phase. Less volatile elements tend to condense onto the surface of smaller particles in the flue gas stream. Therefore, enrichment in the finest particle fractions is observed. The content of heavy metals in coal is normally several orders of magnitude higher than in oil (except occasionally for Ni and V in heavy fuel oil) and in natural gas. For natural gas only emissions of mercury are relevant.

During the combustion of coal, particles undergo complex changes which lead to vaporisation of volatile elements. The rate of volatilisation of heavy metal compounds depends on fuel characteristics (e.g. concentrations in coal, fraction of inorganic components, such as calcium) and on technology characteristics (e.g. type of boiler, operation mode).

From DBB, all heavy metals of concern are emitted as particulate matter, except Hg and Se. Emissions from lignite-fired DBB are potentially lower than from hard coal, as the trace element content in lignite and the combustion temperatures are lower. In WBB, the recirculation of fly ash is a common operation mode, which creates an important increase in heavy metal concentrations in the raw gas. Heavy metal emissions from FBC units are expected to be lower due to the lower operating temperatures and a smaller fraction of fine particles. The addition of limestone in FBC facilities might reduce the emission of some heavy metals, corresponding to an increased retention of heavy metals in the bottom ash. This effect can be partially compensated by the increase in the fraction of fine particulates in the flue gas leading to increased emissions from particulates highly enriched by heavy metals. High concentrations of As poison denitrification catalysts. Therefore, selected catalytic reduction plants (SCR) in a high-dust configuration may require special measures (e.g. reduction of fly ash recirculation).

**Controls**

Relevant abatement technologies for SO2, NOx and heavy metals are outlined below. Abatement techniques for gas turbines and stationary engines are treated separately. Average reduction efficiencies and availabilities of abatement technologies for SOx and NOx are summarised in Tables B1–B3.

***Sulphur oxides: flue gas desulphurisation (FGD) processes***

FGD processes are designed to remove SO2 from the flue gas of combustion installations. Most processes, like the wet scrubbing process (WS), the spray dryer absorption (SDA), the dry sorbent injection (DSI) and the Walther process (WAP) are based on the reaction of the SO2 with an alkaline agent added as solid or as suspension/solution of the agent in water to form the respective salts. In secondary reactions SO3, fluorides and chlorides are also removed. In the case of the DESONOX process, the SO2 is catalytically oxidised to SO3 and reacts with water to form sulphuric acid. The activated carbon process and the Wellman-Lord process remove the SO2 to produce a SO2 rich gas, which may be further processed to sulphur or sulphuric acid.

The Large Combustion Plant BREF indicates that use of low sulphur fuel or co-firing with gas or other low sulphur fuels are primary measures for SO2 control. Wet limestone scrubbing process (with gypsum production) is the main FGD process applied to coal and oil-fired boilers but is rarely applied in plant smaller than 100 MWth. Seawater scrubbing and SDA are listed as alternative possible FGD techniques for new and retrofit boilers. DSI is also listed as possible for coal. Other techniques are considered possible but rarely applied to new plant and would be plant-dependent for existing boilers.

***Nitrogen oxides: primary measures***

*Low NOx burner (LNB)*

A characteristic of LNB is the staged air to fuel ratio at the burner. Three different technical modifications are in use:

* air-staged LNB: an under-stoichiometric zone is created by a fuel-air mixture and primary air. An internal recirculation zone occurs due to the swirl of primary air. A burn-out zone is created due to secondary air fed by air nozzles arranged around the primary air nozzles
* air-staged LNB with flue gas recirculation (FGR): the basic function is similar to air-staged LNB. The distances between the primary and secondary nozzles are greater; therefore, a flue gas layer is formed. As a result, the residence time in the reducing atmosphere increases and the oxygen concentration decreases;
* air-/fuel-staged LNB: an additional reduction zone around the primary zone is achieved by the extremely over-stoichiometric addition of secondary fuel around the secondary flame.

LNB is operational with all fuels and all types of burners. The NOx reduction efficiency for coal-fired boilers varies between 10 and 30 %.

*Staged air supply (SAS)*

Staged air means the creation of two divided combustion zones — a primary zone with a lack of oxygen and a burn-out zone with excess air. SAS covers the low excess air (LEA), burners out of service (BOOS) and biased burner firing (BBF) techniques:

* low excess air (LEA) means reduction of the oxygen content in the primary combustion zone of the burners. When firing hard coal, experience has shown that the general limitations are fouling and corrosion, caused by the reducing atmosphere and incomplete burn-out. When firing gas, the reduction efficiency is limited by the CO formed. LEA is more suitable for lignite and often used for retrofitting combustion plants. For oil-fired boilers a reduction efficiency of 20 % has been achieved
* burners out of service (BOOS) means that the lower burner row(s) in the boiler operate under a lack of oxygen (fuel rich); the upper burners are not in use. This technology is in particular suitable for older installations, but the thermal capacity of the boiler decreases by about 15–20 %
* biased burner firing (BBF) means that the lower burner rows in the boiler operate under a lack of oxygen (fuel rich) and the upper burners with an excess of oxygen. The boiler efficiency is less compared to BOOS and the NOx reduction is also lower. The NOx reduction efficiency for coal-fired boilers varies between 10 and 40 %.

*Overfire air (OFA)*

All burner rows in the boiler operate with a lack of oxygen. The combustion air is partly (5–20 %) injected through separate ports located above the top burner row in the boiler. OFA is operational with most fuels and most types of boilers. For gas-fired boilers a reduction efficiency of 10–30 % and for oil-fired boilers 10–40 % has been achieved. The NOx reduction efficiency for coal-fired boilers varies between 10 and 40 %.

*Flue gas recirculation (FGR)*

The recirculation of flue gas into the combustion air is an efficient NOx abatement method for firing modes with high combustion temperatures, such as wet bottom boilers and especially for gas- and oil-fired boilers. The recirculated flue gas can be added to the secondary or primary air. In the first case, the flame core is not affected and the only effect is a reduction of the flame temperature, which is favourable for thermal-NOx abatement. The influence on dry bottom boilers is thus very limited, considering the fact that about 80 % of the NOx formed originates from fuel-bound nitrogen; FGR can be used as an additional measure. A more efficient method is the introduction of flue gas into the primary air of an unstaged burner. High reduction efficiencies of FGR in the primary flow (15–20 %) have been achieved in gas- and oil-fired boilers. The NOx reduction efficiency for coal-fired boilers varies between 5 and 25 %.

*Split primary flow (SPF or Reburn)*

Split primary flow means fuel staging in the furnace. This technique involves injecting fuel into the furnace above the main combustion zone, thereby producing a second sub-stoichiometric combustion zone. In the primary zone of the boiler the main fuel is burnt under fuel-lean conditions. This zone is followed by a secondary zone with a reducing atmosphere, into which the secondary fuel is injected. Finally, secondary air is injected into the burn-out zone of the boiler. This reburning technique can, in principle, be used for all types of fossil fuel-fired boilers and in combination with low NOx combustion techniques for the primary fuels. When nitrogen is present in the reburning fuel, a part of it will be converted into NOx in the burn-out zone. Therefore, use of natural gas provides the largest potential reduction. Trials on large boilers indicate NOx reduction potentials of 50–70 %.

The Large Combustion Plant BREF lists similar measures for coal- and oil-fired boilers including:

* low excess air;
* air staging (OFA and similar measures);
* LNB;
* reburning.

Reburn is not relevant for natural gas-fired boilers.

***Simultaneous processes for removal of nitrogen oxides and sulphur oxides***

*Activated carbon process (AC)*

The AC process is a dry process for simultaneous SO2 and NOx removal based on the adsorption of the pollutants in a moving bed filter of activated carbon. The sulphur oxides undergo catalytic oxidation with the moisture in the flue gas to form sulphuric acid. NO2 is completely reduced to N2; NO reacts catalytically with the ammonia injected and forms N2 and H2O. The AC process has been installed at four power plants in Germany (in two cases downstream of a SDA process). The sulphur content in the fuel used should not exceed 2.3 wt.-%. The SO2 reduction efficiency is > 95 %, the NOx reduction efficiency is > 70 %.

*The DESONOX process/SNOX process (DESONOX)*

The purification of the flue gas by the DESONOX process is based on the simultaneous catalytic reduction of nitrogen oxides (NOx) to nitrogen (N2) and water (H2O) and on the catalytic oxidation of sulphur dioxide (SO2) to sulphur trioxide (SO3). The by-product is sulphuric acid. The process has been installed at one power plant in Germany, where hard coal is used with a sulphur content of about 1 wt.-%. The concentration of catalyst toxics (mainly arsenic, but also chromium, selenium, etc.) has to be taken into account. The SO2 reduction efficiency is up to 95 %, the NOx reduction efficiency is also up to 95 %. The SNOX process works on the same basic principle as the DESONOX process, with the main difference that reduction and oxidation take place in two separate reaction towers. The SNOX process has been applied at one Danish power plant. No reduction efficiency has been reported yet. The SNOX process is also known as a combination of the Topsøe WSA-2 process and the SCR process.

***Heavy metals: secondary measures***

Heavy metal emissions are mainly reduced by dust control equipment. Particulate control systems, which are used in coal-fired power plants, are cyclones, wet scrubbers, electrostatic precipitators (ESP), and fabric filters. In most power plants 99 % of the particulates are removed from the flue gases by using ESP or fabric filters. The latter are more efficient in controlling fine particulate matter; wet scrubbers and cyclones are less efficient. The reduction efficiency of ESP for most elements in the solid state is > 99 %. Only for some higher volatile elements, such as Cd, Pb, Zn and Se, is the reduction efficiency less, but it remains above 90 %. The reduction efficiency of an ESP for Hg depends on the operating temperature of the ESP. A cold-side ESP operating at about 140 °C is estimated to have an average Hg reduction efficiency of about 35 %.

The influence of FGD- and DeNOx-units on heavy metal emissions has been investigated mainly in the frame of mass balance studies. WS-FGD-units remove a further fraction of particulate matter in flue gas in addition to dust control. Particle-bound elements are removed by FGD-units with an efficiency of about 90 %. In FGD-units, in particular WS-units, the gaseous compounds can additionally condense on particulate matter, which are mainly removed in the prescrubber. With regard to gaseous elements, various studies have shown reduction efficiencies of 30–50 % for Hg and 60–75 % for Se. Lime contributes over 90 % of the input of As, Cd, Pb and Zn to the FGD.

The abatement of Hg emissions is influenced indirectly by DeNOx-units. A high dust SCRunit improves Hg removal in a subsequent FGD-unit using a lime scrubbing system. The SCR-unit increases the share of ionic mercury (HgCl2) to up to 95 %, which can be washed out in the prescrubber of the FGD-unit. A study in the Netherlands found no influence of LNB on heavy metal emissions.

***Gas turbines***

For gas turbines mainly NOx emissions are of most relevance. Primary measures for NOx reduction are the following:

* dry controls (e.g. over-stoichiometric combustion in a dry low NOx burner; and
* wet controls (injection of water and/or steam) in order to regulate the combustion temperature.

***Stationary engines***

For spark-ignition engines the main pollutants emitted are NOx, CO and unburned hydrocarbons (VOC). For diesel engines sulphur dioxide (SO2) emissions have also to be considered. Emissions of soot also contribute to emissions of heavy metals and persistent organic pollutants, but little information is available.

Primary measures are installed to optimise combustion conditions (air ratio, reduced load, water injection, exhaust-gas recirculation, optimised combustion chamber, etc.). Reduction efficiencies can be given, e.g. for exhaust gas recirculation from 6.5 to 12 % and for internal exhaust gas recirculation from 4 to 37 %. External exhaust gas recirculation (turbo-charged models) can have reductions of NOx varying from 25 to 34 %. Secondary measures (NSCR, SCR) are installed if the emission thresholds cannot be met by adjustments to the engine itself.

Table B1 FGD abatement measure efficiencies and availabilities

|  |  |  |  |
| --- | --- | --- | --- |
| **No.** | **Type of secondary measure** | **Reduction efficiency**  **ηsec ­[ ]** | **Availability**  **β [ ]** |
| 1 | WS | 0.90 | 0.99 |
| 2 | SDA | 0.90 | 0.99 |
| 3 | DSI | 0.45 | 0.98 |
| 4 | LIFAC | 0.70 | 0.98 |
| 5 | WL | 0.97 | 0.99 |
| 6 | WAP | 0.88 | 0.99 |
| 7 | AC | 0.95 | 0.99 |
| 8 | DESONOX | 0.95 | 0.99 |

Notes:

WS – lime/limestone wet scrubbing

SDA – spray-dryer absorption

DSI – dry sorbent injection

LIFAC DSI system with additional water injection

WL – Wellman Lord process (regenerable FGD process)

WAP – Walther process

AC – activated carbon process (simultaneous FGD and DeNOx process)

DESONOX – combined FGD and DeNOx process.

Table B2 NOx primary abatement measure efficiencies

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Type of primary measure1)** | **Reduction efficiency DBB η [ ]** | | | | **Reduction efficiency WBB η [ ]** | |
| **Hard coal** | | **Lignite** | | **Hard coal** | |
| **range** | **value3)** | **range** | **value3)** | **range** | **value3)** |
| no measure4) | 0 | 0 | 0 | 0 | 0 | 0 |
| LNB | 0.10 - 0.30 | 0.20 | 0.10 - 0.30 | 0.20 | 0.10 - 0.30 | 0.20 |
| SAS | 0.10 - 0.40 | 0.30 | 0.10 - 0.40 | 0.30 | 0.10 - 0.40 | 0.30 |
| OFA | 0.10 - 0.40 | 0.30 | 0.10 - 0.35 | 0.25 | 0.10 - 0.35 | 0.25 |
| FGR | 0.05 - 0.15 | 0.10 | 0.05 - 0.20 | 0.15 | 0.10 - 0.25 | 0.20 |
| LNB/SAS | 0.20 - 0.60 | 0.45 | 0.20 - 0.60 | 0.40 | 0.20 - 0.60 | 0.45 |
| LNB/OFA | 0.20 - 0.60 | 0.45 | 0.20 - 0.55 | 0.40 | 0.20 - 0.60 | 0.45 |
| LNB/FGR | 0.15 - 0.40 | 0.30 | 0.15 - 0.45 | 0.30 | 0.20 - 0.50 | 0.35 |
| SAS/OFA | 0.20 - 0.65 | 0.50 | 0.20 - 0.60 | 0.40 | 0.20 - 0.60 | 0.40 |
| SAS/FGR | 0.15 - 0.50 | 0.40 | 0.15 - 0.50 | 0.40 | 0.20 - 0.55 | 0.45 |
| OFA/FGR | 0.15 - 0.50 | 0.40 | 0.15 - 0.50 | 0.35 | 0.20 - 0.50 | 0.40 |
| LNB/SAS/OFA | 0.30 - 0.75 | 0.60 | 0.30 - 0.75 | 0.60 | 0.30 - 0.75 | 0.60 |
| LNB/SAS/FGR | 0.25 - 0.65 | 0.50 | 0.25 - 0.70 | 0.50 | 0.30 - 0.70 | 0.55 |
| LNB/OFA/FGR | 0.25 - 0.65 | 0.50 | 0.25 - 0.65 | 0.50 | 0.30 - 0.65 | 0.50 |
| old installation/optimised | 0.15 | | 0.15 | | 0.15 | |
| old installation/retrofitted2) | 0.50 | | 0.50 | | 0.50 | |
| new installation2) | 0.40 | | 0.40 | | 0.40 | |

Note:

Selection from the DECOF database developed by and available at the Institute for Industrial Production (IPP)

Recommended values, when no information concerning the type of primary measure is available

Default values used in the computer programme

No primary measures are installed. This case is mainly relevant for old installations.

Table B3 NOx secondary abatement measure efficiencies and availabilities

|  |  |  |  |
| --- | --- | --- | --- |
| **No.** | **Type of secondary measure** | **Reduction efficiency η [ ]** | **Availabilty β [ ]** |
| 1 | SNCR | 0.50 | 0.99 |
| 2 | SCR | 0.80 | 0.99 |
| 3 | AC | 0.70 | 0.99 |
| 4 | DESONOX | 0.95 | 0.99 |

1. Sulphur content in fuels

Fuel sulphur contents from the previous Guidebook (Chapter B111).

Table C-1 Sulphur content in fuels

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Type of fuel** | | | | | **Sulphur content of fuel** | | | |
| **NAPFUE code** | **value1)** | **range** | **unit** |
| Solid | Coal | hc | coking | 101 | |  | 0.4 – 6.2 | wt.-% (maf) |
| hc | steam | 102 | |  | 0.4 – 6.2 | wt.-% (maf) |
| hc | sub-bituminous | 103 | |  | 0.4 – 6.2 | wt.-% (maf) |
| bc | broan coal/ligninte | 105 | |  | 0.4 – 6.2 | wt.-% (maf) |
| bc | briquettes | 106 | |  | 0.25 – 0.4510) | wt.-% (maf) |
| Coke | hc | coke oven | 107 | |  | < 13) | wt.-% (maf) |
| bc | coke oven | 108 | |  | 0.5 – 1 3) 4) | wt.-% (maf) |
|  | petroleum | 110 | |  |  |  |
| Biomass |  | wood | 111 | |  | < 0.033) | wt.-% (maf) |
|  | charcoal | 112 | |  | < 0.033) | wt.-% (maf) |
|  | peat | 113 | |  |  |  |
| Waste |  | municipal | 114 | |  |  |  |
|  | industrial | 115 | |  |  |  |
|  | wood | 116 | |  |  |  |
|  | agricultural | 117 | |  |  |  |
| Liquid | Oil |  | residual | 203 | |  | 0.3 5) – 3.5 6) | wt.-% |
|  | gas | 204 | | 0.38) | 0.08 – 1.0 | wt.-% |
|  | diesesl | 205 | | 0.38) |  | wt.-% |
| kerosene |  | motor | 206 | |  | < 0.059) | wt.-% |
| gasoline |  | 208 | |  |
| naphtha |  | 210 | |  |
| black liquour |  | 215 | |  |
| Gas | Gas2) |  | natural | 301 | | 0.00757) |  | g·m-3 |
| Gas |  | liquified petroleum gas | 303 | | - |  |  |
|  | coke oven | 304 | | 8 |  | g·m-3 |
|  | blast furnace | 305 | | 45·10-3 7) |  | g·m-3 |
|  | coke oven and blast furnace | 306 | |  |  |  |
|  | waste | 307 | |  |  |  |
|  | refinery | 308 | |  | ≤ 8 7) | g·m-3 |
|  | biogas | 309 | |  |  |  |
|  | from gas works | 311 | |  |  |  |

Notes:

Recommended value

Only trace amounts

Marutzky 1989

Boelitz 1993

Mr. Hietamäki (Finland): personal communication

Referring to NL-handbook 1988/99/ the range is 2.0 – 3.5

NL-handbook 1988

87/219 CEE 1987

as ~ 0

Davids 1986

1. Emission factors derived from emission limit values

Table D1 TSP

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Source**  **[1]** | **Fuel type [2]** | **New or existing plant [3]** | **Boiler size or technology, MWth** | **Reference O2 content,**  **%v/v dry** | **AEL or ELV concentration, mg.m-3 at STP (0ºC, 101.3 kPa) dry at reference O2 content** | | **Emission factor[4], g·GJ-1**  **(net thermal input)** | |
|  |  |  |  |  | **Low** | **High** | **Low** | **High** |
| BREF | coal | new | 50-100 | 6 | 5 | 20 | 1.8 | 7.2 |
| BREF | coal | new | 100-300 | 6 | 5 | 20 | 1.8 | 7.2 |
| BREF | coal | new | > 300 | 6 | 5 | 20 | 1.8 | 7.2 |
| LCPD | coal | new | 50-500 | 6 | 100 |  | 36.2 |  |
| LCPD | coal | new | > 500 | 6 | 50 |  | 18.1 |  |
| LCPD | coal | new | 50-100 | 6 | 50 |  | 18.1 |  |
| LCPD | coal | new | > 100 | 6 | 30 |  | 10.9 |  |
| BREF | coal | existing | 50-100 | 6 | 5 | 30 | 1.8 | 10.9 |
| BREF | coal | existing | 100-300 | 6 | 5 | 30 | 1.8 | 10.9 |
| BREF | coal | existing | > 300 | 6 | 5 | 30 | 1.8 | 10.9 |
| LCPD | coal | existing | 50-500 | 6 | 100 |  | 36.2 |  |
| LCPD | coal | existing | > 500 | 6 | 50 |  | 18.1 |  |
| BREF | wood | new | 50-100 | 6 | 5 | 20 | 1.9 | 7.7 |
| BREF | wood | new | 100-300 | 6 | 5 | 20 | 1.9 | 7.7 |
| BREF | wood | new | > 300 | 6 | 5 | 20 | 1.9 | 7.7 |
| BREF | wood | existing | 50-100 | 6 | 5 | 20 | 1.9 | 7.7 |
| BREF | wood | existing | 100-300 | 6 | 5 | 20 | 1.9 | 7.7 |
| BREF | wood | existing | > 300 | 6 | 5 | 20 | 1.9 | 7.7 |
| BREF | oil | new | 50-100 | 3 | 5 | 20 | 1.4 | 5.7 |
| BREF | oil | new | 100-300 | 3 | 5 | 20 | 1.4 | 5.7 |
| BREF | oil | new | > 300 | 3 | 5 | 10 | 1.4 | 2.8 |
| LCPD | oil | new | > 50 | 3 | 50 |  | 14.1 |  |
| LCPD | oil | new | 50-100 | 6 | 50 |  | 17.0 |  |
| LCPD | oil | new | > 100 | 6 | 30 |  | 10.2 |  |
| BREF | oil | existing | 50-100 | 3 | 5 | 30 | 1.4 | 8.5 |
| BREF | oil | existing | 100-300 | 3 | 5 | 25 | 1.4 | 7.1 |
| BREF | oil | existing | > 300 | 3 | 5 | 20 | 1.4 | 5.7 |
| LCPD | oil | existing | > 50 | 3 | 50 |  | 14.1 |  |
| LCPD | gas | new | > 50 | 3 | 5 |  | 1.4 |  |
| LCPD | gas | new | > 50 | 3 | 5 |  | 1.4 |  |
| LCPD | gas | existing | > 50 | 3 | 5 |  | 1.4 |  |

Notes:

BREF denotes the large combustion plant BAT reference document, LCPD denotes Directive 2001/80/EC.

Fuel is main classification only, limits may be for ‘solid fuels’ rather than coal or wood. Limits for gaseous fuels are for natural gas and may not be applicable to derived or other gaseous fuels.

Note that new and existing plant have specific meanings under LCPD.

Emission factors calculated from emission concentrations using USEPA methodology (See Appendix E for details).

Table D2 Nitrogen oxides

| **Source**  **[1]** | **Fuel type [2]** | **New or existing plant [3]** | **Boiler size or technology, MWth** | **Reference O2 content,**  **%v/v dry** | **AEL or ELV concentration, mg NO2.m-3 at STP (0ºC, 101.3 kPa) dry at reference O2 content** | | **Emission factor [4], g·GJ-1**  **(net thermal input)** | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **Low** | **High** | **Low** | **High** |
| BREF | coal | new | 50-100 | 6 | 90 | 300 | 32.6 | 108.7 |
| BREF | coal | new | 100-300 | 6 | 90 | 200 | 32.6 | 72.5 |
| BREF | coal | new | > 300 | 6 | 50 | 150 | 18.1 | 54.3 |
| LCPD | coal | new | 50-500 | 6 | 600 |  | 217.4 |  |
| LCPD | coal | new | > 500 | 6 | 500 |  | 181.1 |  |
| LCPD | coal | New 2016 | > 500 | 6 | 200 |  | 72.5 |  |
| Goburg | coal | new | 50-100 | 6 | 400 |  | 144.9 |  |
| Goburg | coal | new | 100-300 | 6 | 300 |  | 108.7 |  |
| Goburg | coal | new | > 300 | 6 | 200 |  | 72.5 |  |
| BREF | coal | existing | 50-100 | 6 | 90 | 300 | 32.6 | 108.7 |
| BREF | coal | existing | 100-300 | 6 | 90 | 200 | 32.6 | 72.5 |
| BREF | coal | existing | > 300 | 6 | 50 | 200 | 18.1 | 72.5 |
| LCPD | coal | existing | 50-500 | 6 | 600 |  | 217.4 |  |
| LCPD | coal | existing | > 500 | 6 | 500 |  | 181.1 |  |
| LCPD | coal | Ex. 2016 | > 500 | 6 | 200 |  | 72.5 |  |
| Goburg | coal | existing | > 50 | 6 | 650 |  | 235.5 |  |
| BREF | wood | new | 50-100 | 6 | 150 | 250 | 57.9 | 96.4 |
| BREF | wood | new | 100-300 | 6 | 150 | 200 | 57.9 | 77.1 |
| BREF | wood | new | > 300 | 6 | 50 | 150 | 19.3 | 57.9 |
| LCPD | wood | new | 50-100 | 6 | 400 |  | 154.3 |  |
| LCPD | wood | new | 100-500 | 6 | 300 |  | 115.7 |  |
| LCPD | wood | new | > 500 | 6 | 200 |  | 77.1 |  |
| Goburg | wood | new | 50-100 | 6 | 400 |  | 154.3 |  |
| Goburg | wood | new | 100-300 | 6 | 300 |  | 115.7 |  |
| Goburg | wood | new | > 300 | 6 | 200 |  | 77.1 |  |
| BREF | wood | existing | 50-100 | 6 | 150 | 300 | 57.9 | 115.7 |
| BREF | wood | existing | 100-300 | 6 | 150 | 250 | 57.9 | 96.4 |
| BREF | wood | existing | > 300 | 6 | 50 | 200 | 19.3 | 77.1 |
| Goburg | wood | existing | > 50 | 6 | 650 |  | 250.7 |  |
| BREF | oil | new | 50-100 | 3 | 150 | 300 | 42.4 | 84.9 |
| BREF | oil | new | 100-300 | 3 | 50 | 150 | 14.1 | 42.4 |
| BREF | oil | new | > 300 | 3 | 50 | 100 | 14.1 | 28.3 |
| LCPD | oil | new | 50-100 | 3 | 400 |  | 113.2 |  |
| LCPD | oil | new | 100-300 | 3 | 200 |  | 56.6 |  |
| LCPD | oil | new | > 300 | 3 | 200 |  | 56.6 |  |
| Goburg | oil | new | 50-100 | 3 | 400 |  | 113.2 |  |
| Goburg | oil | new | 100-300 | 3 | 300 |  | 84.9 |  |
| Goburg | oil | new | > 300 | 3 | 200 |  | 56.6 |  |
| BREF | oil | existing | 50-100 | 3 | 150 | 450 | 42.4 | 127.3 |
| BREF | oil | existing | 100-300 | 3 | 50 | 200 | 14.1 | 56.6 |
| BREF | oil | existing | > 300 | 3 | 50 | 150 | 14.1 | 42.4 |
| LCPD | oil | existing | 50-500 | 3 | 450 |  | 127.3 |  |
| LCPD | oil | existing | > 500 | 3 | 400 |  | 113.2 |  |
| Goburg | oil | existing | > 50 | 3 | 450 |  | 127.3 |  |
| BREF | gas | new | > 50 | 3 | 50 | 100 | 14.2 | 28.3 |
| LCPD | gas | new | 50-300 | 3 | 150 |  | 42.5 |  |
| LCPD | gas | new | > 300 | 3 | 100 |  | 28.3 |  |
| Goburg | gas | new | 50-300 | 3 | 150 |  | 42.5 |  |
| Goburg | gas | new | > 300 | 3 | 100 |  | 28.3 |  |
| BREF | gas | existing | > 50 | 3 | 50 | 100 | 14.2 | 28.3 |
| LCPD | gas | existing | 50-500 | 3 | 300 |  | 85.0 |  |
| LCPD | gas | existing | > 500 | 3 | 200 |  | 56.6 |  |
| Goburg | gas | existing | > 50 | 3 | 350 |  | 99.1 |  |

Notes :

BREF denotes the large combustion plant BAT reference document, LCPD denotes Directive 2001/80/EC, Goburg denotes the Gothenburg protocol of 1999.

Fuel is main classification only, limits may be for ‘solid fuels’ rather than coal or wood. Limits for gaseous fuels are for natural gas and may not be applicable to derived or other gaseous fuels.

Note that new and existing plant have specific meanings under LCPD.

Emission factors calculated from emission concentrations using USEPA methodology (See Appendix E for details).

Table D3 Sulphur oxides/dioxide

| Source  [1] | Fuel type [2] | New or existing plant [3] | Boiler size or technology, MWth | Reference O2 content,  %v/v dry | AEL or ELV concentration, mg.m-3 at STP (0ºC, 101.3 kPa) dry at reference O2 content | | Emission factor [4], g·GJ-1  (net thermal input) | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | Low | High | Low | High |
| BREF | coal | new | 50-100 | 6 | 150 | 400 | 54.3 | 144.9 |
| BREF | coal | new | 100-300 | 6 | 100 | 200 | 36.2 | 72.5 |
| BREF | coal | new | > 300 | 6 | 20 | 200 | 7.2 | 72.5 |
| LCPD | coal | new | 50-100 | 6 | 2000 |  | 724.5 |  |
| LCPD | coal | new | 100-500 | 6 | 400 | 2000 | 144.9 | 724.5 |
| LCPD | coal | new | > 500 | 6 | 400 |  | 144.9 |  |
| Goburg | coal | new | 50-100 | 6 | 850 |  | 307.9 |  |
| Goburg | coal | new | 100-300 | 6 | 200 | 850 | 72.5 | 307.9 |
| Goburg | coal | new | > 300 | 6 | 200 |  | 72.5 |  |
| BREF | coal | existing | 50-100 | 6 | 150 | 400 | 54.3 | 144.9 |
| BREF | coal | existing | 100-300 | 6 | 100 | 250 | 36.2 | 90.6 |
| BREF | coal | existing | > 300 | 6 | 20 | 200 | 7.2 | 72.5 |
| LCPD | coal | existing | 50-100 | 6 | 2000 |  | 724.5 | 0.0 |
| LCPD | coal | existing | 100-500 | 6 | 400 | 2000 | 144.9 | 724.5 |
| LCPD | coal | existing | > 500 | 6 | 400 |  | 144.9 |  |
| Goburg | coal | existing | 50-100 | 6 | 2000 |  | 724.5 |  |
| Goburg | coal | existing | 100-500 | 6 | 400 | 2000 | 144.9 | 724.5 |
| Goburg | coal | existing | > 500 | 6 | 400 |  | 144.9 | 0.0 |
| BREF | wood | new | 50-100 | 6 | 200 | 300 | 77.1 | 115.7 |
| BREF | wood | new | 100-300 | 6 | 150 | 300 | 57.9 | 115.7 |
| BREF | wood | new | > 300 | 6 | 50 | 200 | 19.3 | 77.1 |
| LCPD | wood | new | 50-100 | 6 | 200 |  | 77.1 |  |
| LCPD | wood | new | 100-500 | 6 | 200 |  | 77.1 |  |
| LCPD | wood | new | > 500 | 6 | 200 |  | 77.1 |  |
| Goburg | wood | new | 50-100 | 6 | 850 |  | 327.8 |  |
| Goburg | wood | new | 100-300 | 6 | 200 | 850 | 77.1 | 327.8 |
| Goburg | wood | new | > 300 | 6 | 200 |  | 77.1 |  |
| BREF | wood | existing | 50-100 | 6 | 200 | 300 | 77.1 | 115.7 |
| BREF | wood | existing | 100-300 | 6 | 150 | 300 | 57.9 | 115.7 |
| BREF | wood | existing | > 300 | 6 | 50 | 200 | 19.3 | 77.1 |
| Goburg | wood | existing | 50-100 | 6 | 2000 |  | 771.4 |  |
| Goburg | wood | existing | 100-500 | 6 | 400 | 2000 | 154.3 | 771.4 |
| Goburg | wood | existing | > 500 | 6 | 400 |  | 154.3 |  |
| BREF | oil | new | 50-100 | 3 | 100 | 350 | 28.3 | 99.0 |
| BREF | oil | new | 100-300 | 3 | 100 | 200 | 28.3 | 56.6 |
| BREF | oil | new | > 300 | 3 | 50 | 150 | 14.1 | 42.4 |
| LCPD | oil | new | 50-100 | 3 | 850 |  | 240.5 |  |
| LCPD | oil | new | 100-300 | 3 | 200 | 400 | 56.6 | 113.2 |
| LCPD | oil | new | > 300 | 3 | 200 |  | 56.6 |  |
| Goburg | oil | new | 50-100 | 3 | 850 |  | 240.5 |  |
| Goburg | oil | new | 100-300 | 3 | 200 | 850 | 56.6 | 240.5 |
| Goburg | oil | new | > 300 | 3 | 200 |  | 56.6 |  |
| BREF | oil | existing | 50-100 | 3 | 100 | 350 | 28.3 | 99.0 |
| BREF | oil | existing | 100-300 | 3 | 100 | 250 | 28.3 | 70.7 |
| BREF | oil | existing | > 300 | 3 | 50 | 200 | 14.1 | 56.6 |
| LCPD | oil | existing | 50-300 | 3 | 1700 |  | 481.0 |  |
| LCPD | oil | existing | 300-500 | 3 | 400 | 1700 | 113.2 | 481.0 |
| LCPD | oil | existing | > 500 | 3 | 400 |  | 113.2 |  |
| Goburg | oil | existing | 50-300 | 3 | 1700 |  | 481.0 |  |
| Goburg | oil | existing | 300-500 | 3 | 400 | 1700 | 113.2 | 481.0 |
| Goburg | oil | existing | > 500 | 3 | 400 |  | 113.2 |  |
| Goburg | gas | new | > 50 | 3 | 35 |  | 9.9 |  |
| LCPD | gas | new | > 50 | 3 | 35 |  | 9.9 |  |
| LCPD | gas | existing | > 50 | 3 | 35 |  | 9.9 |  |
| Goburg | gas | existing | > 50 | 3 | 35 |  | 9.9 |  |

Notes :

BREF denotes the large combustion plant BAT reference document, LCPD denotes Directive 2001/80/EC, Goburg denotes the Gothenburg protocol of 1999.

Fuel is main classification only, limits may be for ‘solid fuels’ rather than coal or wood. Limits for gaseous fuels are for natural gas and may not be applicable to derived or other gaseous fuels.

Note that new and existing plant have specific meanings under LCPD.

Emission factors calculated from emission concentrations using USEPA methodology (See Appendix E for details).

Table D4 Gas turbines and stationary engines

| **Source**  **[1]** | **Fuel type [2]** | **New or existing plant [3]** | **Technology** | **Reference O2 content,**  **%v/v dry** | **Pollutant** | **AEL or ELV concentration, mg.m-3 at STP (0ºC, 101.3 kPa) dry at reference O2 content** | | **Emission factor [4], g·GJ-1**  **(net thermal input)** | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  |  | **Low** | **High** | **Low** | **High** |
|  |  |  |  |  |  |  |  |  |  |
| BREF | gas | new | GT | 15 | TSP | 5 |  | 4.3 |  |
| BREF | gas | existing | GT | 15 | TSP | 5 |  | 4.3 |  |
| BREF | gas | new | GT | 15 | SO2 | 10 |  | 8.6 |  |
| BREF | gas | existing | GT | 15 | SO2 | 10 |  | 8.6 |  |
| BREF | gas | new | GT | 15 | NOx | 20 | 50 | 17.2 | 43.0 |
| LCPD | gas | new | GT | 15 | NOx | 50 | 75 | 43.0 | 64.4 |
| LCPD | oil | new | GT | 15 | NOx | 120 |  | 103.0 |  |
| Goburg | gas | new | GT | 15 | NOx | 50 | 75 | 43.0 | 64.4 |
| Goburg | oil | new | GT | 15 | NOx | 120 |  | 103.0 |  |
| BREF | gas | existing | GT | 15 | NOx | 20 | 90 | 17.2 | 77.3 |
| Goburg | gas | existing | GT | 15 | NOx | 150 |  | 128.9 |  |
| Goburg | oil | existing | GT | 15 | NOx | 200 |  | 171.7 |  |
|  |  |  |  |  |  |  |  |  |  |
| BREF | gas | new | Gas engine | 15 | NOx | 20 | 75 | 17.2 | 64.4 |
| Goburg | gas | new | Gas engine | 5 | NOx | 250 | 500 | 79.7 | 159.4 |
| BREF | gas | existing | Gas engine | 15 | NOx | 20 | 100 | 17.2 | 85.9 |
|  |  |  |  |  |  |  |  |  |  |
| Goburg | gas | new | CI Engine | 5 | NOx | 500 |  | 159.4 |  |
| Goburg | oil | new | CI Engine | 5 | NOx | 500 | 600 | 159.3 | 191.1 |

Notes :

BREF denotes the large combustion plant BAT reference document, LCPD denotes Directive 2001/80/EC, Goburg denotes the Gothenburg protocol of 1999.

Fuel is main classification only, limits may be for ‘solid fuels’ rather than coal or wood. Limits for gaseous fuels are for natural gas and may not be applicable to derived or other gaseous fuels.

Note that new and existing plant have specific meanings under LCPD.

Emission factors calculated from emission concentrations using USEPA methodology (See Appendix E for details).

1. Calculation of emission factors from concentrations

**E.1 Emission factors for combustion activities**

Standardisation of emission concentrations from combustion activities

Annual emissions, emission rates and emission limit values are generally expressed in terms of pollutant mass (for example tonnes.year-1, kg.hr-1, mg.m-3). Note that a mass concentration is meaningless unless the volume conditions are defined — typically for a combustion process the conditions will be a dry volume, at STP (0 °C, 101.3 kPa) and normalised to a reference oxygen concentration. Consumption of fuel requires a minimum theoretical (stoichiometric) quantity of air. In practise, more air than the stoichiometric quantity is required to achieve combustion. The oxygen content in exhaust gases from a combustion appliance is indicative of the amount of excess air and air ingress in the combustion system. Normalisation to a reference oxygen content allows comparison between technologies as it removes a diluting (or concentrating) effect of different levels of excess air/air ingress on the pollutant concentration.

Common oxygen concentrations for emission normalisation are :

* oil- or gas-fired boilers — 3 % O2
* solid-fuel boilers — 6, 7 % O2
* wood-fired boilers — 6, 10, 11 or, 13 % O2
* incineration — 11 % O2
* gas turbines — 15 % O2
* stationary engines — 5, 15 % O2
* dryers — 17 % O2

Other normalisation oxygen concentrations are used including 0 % O2 which is commonly used in testing of residential gas appliances. Concentrations can also be normalised using carbon dioxide (although this is much less common).

Usually emission concentration data will be provided as mass concentrations at a specified oxygen content. However, where emission data are provided in other forms the following equations may help the user manipulate the date into a more useful form.

Some pollutants are measured and reported on a wet basis and may require standardisation to the dry condition.

[X]d = [X]w . 100

(100-[H2O])

where:

[X]w is the measured concentration for a wet flue gas (ppm, mg.m-3, %v/v);

[X]d is the measured concentration for a dry flue gas (same units as the dry concentration);

[H2O] is the flue gas moisture content as % v/v on a wet basis.

Many pollutants are measured as volume (molar) concentrations. Conversion to a mass concentration assumes ideal gas behaviour and is detailed below:

[X]m = [X]d . MW

22.4

where:

[X]d is the measured concentration in ppm (parts per million) by volume for a dry flue gas;

[X]m is the measured concentration in mg.m-3 by volume for a dry flue gas;

MW is the relative molecular mass of the pollutant (for example 64 for SO2);

22.4 is the volume occupied by 1 kgmole of an ideal gas at 0 °C, 101.3 kPa (m3);

Note that NOx emission concentrations and emission factors are defined in terms of NO2. Hence, the relative molecular mass used for NOx is 46. VOC emission concentrations are often defined in terms of carbon. Hence, the relative molecular mass used for VOC is 12, but this will often be modified further for the calibration gas applied (for example MW for concentrations measured as propane C3H8 ‘equivalents’ would be 3 x 12 = 36).

Normalisation to a reference O2 concentration is given by :

[X]ref = [X]m . (20.9-[ O2]ref)

(20.9-[O2]m)

where :

[X]ref is the standardised concentration of the pollutant at the reference O2 content;

[x]m is the measured concentration in mg.m-3 for a dry flue gas;

[O2]m is the measured O2 concentration in % on a dry basis;

[O2]ref is the reference O2 concentration in % on a dry basis (for example 3, 6 or 15 %).

This calculation is appropriate where pollutant and O2 concentrations are measured on a dry basis.

**Calculation of emission factors**

An emission factor relates the release of a pollutant to a process activity. For combustion processes, emission factors are commonly described as the mass of pollutant released per unit of fuel burned.

An emission factor can be calculated in several ways; the approach adopted uses the standardised pollutant emission concentrations and the specific theoretical (stoichiometric) volume of flue gas for the relevant fuel. This approach avoids measurement of exhaust gas flow and fuel flows which can have a high uncertainty and may not be practical at many combustion plant.

The approach requires knowledge of the fuel used, the pollutant concentration and the oxygen concentration.

Fuel analysis, where available, allows calculation of the specific flue gas volume from the elemental analysis. However, the US Environmental Protection Agency Method 19 provides flue gas volume for common fuels. For other fuels (for example derived gases, landfill gas, unrefined natural gas or waste-derived fuels) fuel analysis is advised to minimise uncertainty.

Fuel analysis route: the fuel analysis and combustion calculations are used to determine the stoichiometric air requirement and dry flue gas volume per volume or mass of fuel. Note that it is important to understand the analysis reporting conditions, particularly for solid fuels. The calculations assume ideal gas behaviour. A dry flue gas volume is calculated for the reference O2 concentration used to normalise the pollutant emission concentration. A pollutant emission factor (EF) can hence be calculated by multiplying the standardised pollutant concentration by the dry flue gas volume at the same reference oxygen content.

Generally, the flue gas volumes generated from combustion of fuel can be calculated in accordance with the following equations.

CXHY + (X+(Y/4)O2 = X CO2 + (Y/2) H2O

Note that some of the oxygen may be sourced from the fuel. For combustion in air, each cubic metre of oxygen is associated with (79.1/20.9) cubic metres of nitrogen.

The dry flue gas volume at stoichiometric conditions (DFGVSC) per unit mass of fuel (or volume for gaseous fuels) can be calculated and hence the dry flue gas volume at the normalised condition (DFGVref) for the required reference oxygen content:

DFGVref = DFGVSC . (20.9/(20.9-[O2ref]))

A pollutant emission factor (EF) can hence be calculated by multiplying the standardised pollutant concentration by the dry flue gas volume at the same reference oxygen content. For example at 15 % oxygen:

EF = [X]15 % . DFGV15

Emission factors are reported in several ways and these are generally recalculated using physical or other properties of the fuel.

For example, a thermal emission factor (as used in the Guidebook) can be derived by dividing the emission factor calculated above by the calorific value of the fuel. For the Guidebook this is the net (inferior) CV.

EFthermal = EF

CV

where:

EFthermal is the thermal emission factor expressed in units to suit the user (for example g GJ-1);

CV is the net calorific value of the fuel in appropriate units to suit the units of the emission factor.

USEPA Method 19: The USEPA provides stoichiometric dry flue gas volume for fuel oil. The USEPA data can be found in USEPA Method 19 (US Code of Federal Regulations, Title 40, Part 60, Appendix A). The USEPA ‘F-factor’ data are presented as the volume of dry flue gas at 20 °C associated with the gross thermal input of the fuel. These USEPA conditions are not consistent with the Guidebook (net calorific basis) or emission concentration reporting practise in Europe (dry gas at STP — 0ºC, 101.3 kPa) and consequently some manipulation of the data is required. Calculations assume an ideal gas.

The USEPA method can be obtained here [www.epa.gov/ttn/emc/methods/method19.html](http://www.epa.gov/ttn/chief/ap42) and the F-factors are provided below.

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Fuel type** | **Fd1)** | | **Fw1)** | | **Fc1)** | | |
| **dscm/J** | **dscf/106 Btu** | **wscm/J** | **wscf/106 Btu** | | **scm/J** | **scf/106 Btu** |
| Coal |  |  |  |  | |  |  |
| *Anthracite2* | 2.71·10-7 | 10100 | 2.83·10-7 | 10540 | | 0.530·10-7 | 1970 |
| *Bituminus2* | 2.63·10-7 | 9780 | 2.86·10-7 | 10640 | | 0.484·10-7 | 1800 |
| *Lignite* | 2.65·10-7 | 9860 | 3.21·10-7 | 11950 | | 0.513·10-7 | 1910 |
| Oil3) | 2.47·10-7 | 9190 | 2.77·10-7 | 10320 | | 0.383·10-7 | 1420 |
| Gas |  |  |  |  | |  |  |
| *Natural* | 2.34·10-7 | 8710 | 2.85·10-7 | 10610 | | 0.287·10-7 | 1040 |
| *Propane* | 2.34·10-7 | 8710 | 2.74·10-7 | 10200 | | 0.321·10-7 | 1190 |
| *Butane* | 2.34·10-7 | 8710 | 2.79·10-7 | 10390 | | 0.337·10-7 | 1250 |
| Wood | 2.48·10-7 | 8710 | - | - | | 0.492·10-7 | 1830 |
| Wood bark | 2.58·10-7 | 9240 | - | - | | 0.516·10-7 | 1920 |
| Municipal | 2.57·10-7 | 9600 | - | - | | 0.488·10-7 | 1820 |
| Solid waste | - | 9570 |  |  | |  |  |

Notes:

determined at standard conditions: 20°C (68°F) and 760mmHg (29.92 in·Hg)

as classified according to ASTM D 388

Crude, residual or distillate

The Fd factors are used — these represent the dry stoichiometric flue gas volume per unit of energy input. The Fw and Fc factors represent the wet flue gas volume and CO2 volumes respectively.

The USEPA dry flue gas volume at stoichiometric conditions are first recalculated to provide the flue gas volume (DFGVref) for the required oxygen content at STP and for the net energy input.

Fd’ = Fd · (273/293) · ((CVgross)/CVnet))

Where :

Fd’ is the stoichiometric dry flue gas volume at STP per unit of net energy input – m3·J-1

Fd is the USEPA factor (20 °C and gross energy input)

273/293 Volume correction — ratio of temperatures in Kelvin

Note that it is the ratio between the fuels’ gross and net calorific values that is needed. Indicative ratios are provided below based on UK data (DUKES 2007).

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Fuel** | **CVgross** | **CVnet** | **Unit** | **Ratio gross/net** |
| Power stn coal | 26.2 | 24.9 | GJ·tonne-1 | 1.05 |
| Industrial coal | 26.6 | 25.3 | GJ·tonne-1 | 1.05 |
| Wood | 11.9 | 10 | GJ·tonne-1 | 1.08 |
| HFO | 43.3 | 41.2 | GJ·tonne-1 | 1.05 |
| Gas oil | 45.6 | 43.4 | GJ·tonne-1 | 1.05 |
| Natural gas | 39.8 | 35.8 | MJ·m-3 | 1.11 |

The dry flue gas volume at the normalised oxygen content can then be calculated:

Fdref = Fd’ · (20.9/(20.9-[O2ref]))

A pollutant emission factor (EFthermal) can then be calculated by multiplying the standardised pollutant concentration by the dry flue gas volume at the same reference oxygen content. For example at 15 % oxygen:

EFthermal = [X]15 % · Fd15 %

Emission factors are reported in several ways and these are generally recalculated using physical or other properties of the fuel.

For example, a mass emission factor can be derived by multiplying the thermal emission factor calculated above by the net calorific value of the fuel.

EF = EFthermal · CV

where:

EFthermal is the thermal emission factor expressed in units to suit the user (for example g GJ-1);

CV is the net calorific value of the fuel in appropriate units to suit the units of the emission factor.

Example figures for correlation of emission concentrations to emission factors from USEPA Method 19 F factors are provided in Figures C1 and C2 below.

Figure E1 Emission factors — selected fuels and standardised concentrations up to 1 000 mg.m-3



Figure E2 Emission factors — selected fuels and standardised concentrations up to 200 mg.m-3



1. Emission factors from older versions of the Guidebook

**Chapter B111**





**Chapter B111(S1)PMv1**

Table 7.2a Emission factors for combustion processes burning hard coal

| **Fuel** | **NAPFUE** | **NFR Codes** | **Activity description** | **Activity detail** | **Emission factor** | | | **Notes** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Hard coal** |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Bituminous coal | 101 | Various | Electricity, CHP, heat | FF < 20 mg·Nm-3 | 6 | 6 | 5 | CEPMEIP ‘BAT’ |
| ESP (or FF) < 50 mg·Nm-3 | 15 | 12 | 6 | Scaled from CEPMEIP ESP factor. TSP scaled to a nominal 100 mg·Nm-3 limit |
| ESP < 100 mg·Nm-3 | 30 | 25 | 12 | From CEPMEIP sub-bit coal ‘high efficiency ESP’, TSP scaled to a nominal 100 mg·Nm-3 limit |
| ESP Old/conventional < 500 mg·Nm-3 | 140 | 70 | 17 | CEPMEIP |
| Unit with multicyclone | 100 | 60 | 35 | CEPMEIP |
| Unit, uncontrolled or cyclone | 500 | 250 | 100 | CEPMEIP (N.B. such a high emission concentration would apply to few if any plant) |
| Sub-bituminous coal | 103 | Various | Electricity, CHP, heat plant | FF < 20 mg·Nm-3 | 6 | 6 | 5 | CEPMEIP ‘BAT’ |
| ESP (or FF)  < 50 mg·Nm-3 | 15 | 12 | 6 | Scaled from CEPMEIP ESP factor (TSP scaled to a nominal 100 mg·Nm-3 limit) |
| ESP  < 100 mg·Nm-3 | 30 | 25 | 12 | From CEPMEIP sub-bit coal ‘high efficiency ESP’, TSP scaled to a nominal 100 mg·Nm-3 limit |
| ESP Old/conventional  < 500 mg·Nm-3 | 140 | 70 | 17 | CEPMEIP |
| Unit with multicyclone | 100 | 60 | 35 | CEPMEIP |
| Unit, uncontrolled or cyclone | 500 | 250 | 100 | CEPMEIP (the lower of the two TSP factors, the 800 g GJ-1 for small uncontrolled plant is such a high emission concentration that would apply to few if any plant) |
| Coke | 107 | 1.A.1.b | Oil refineries | Uncontrolled | 500 | 250 | 100 | Coke is unlikely to be burned as primary fuel, when co-fired use the factor for the principal fuel |

Table 7.2b Emission factors for combustion processes burning brown coal

| **Fuel** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Notes** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Brown coal | 105 | Various | Electricity plant, CHP plant, heat plant | Modern FF < 20 mg·Nm-3 | 9 | 8 | 6 | CEPMEIP ‘BAT’ |
|  |  |  |  | High efficiency ESP (or FF) | 40 | 30 | 14 | CEPMEIP |
|  |  |  |  | Conventional large unit with multicyclone | 100 | 60 | 35 | CEPMEIP |
| Peat | 113 | Various | Electricity plant, CHP plant, heat plant | Modern abatement (FF) < 30 mg·Nm3 | 9 | 8 | 6 | CEPMEIP |
|  |  |  |  | Efficient abatement, < 50 mg·Nm3 | 20 | 15 | 10 | TSP scaled from emission limit of 50 mg·Nm-3 |
|  |  |  |  | Efficient abatement, < 100 mg·Nm3 | 40 | 30 | 20 | TSP scaled from emission limit of 100 mg·Nm-3 |
|  |  |  |  | Conventional technology | 120 | 40 | 20 | CEPMEIP |
|  |  |  |  | Conventional smaller, multicyclone | 300 | 40 | 20 | CEPMEIP |

Table 7.2c Emission factors for combustion processes burning other solid fuels

| **Fuel** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Notes** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Municipal solid waste | 114 | Various | Electricity plant, CHP plant, heating plant | Effective emission control (BAT) | 15 | 13 | 10 | CEPMEIP (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification) |
| Conventional emission control | 100 | 70 | 55 | CEPMEIP (uncontrolled. optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification) |
| Industrial waste | 115 | Various | Electricity, CHP, heating plant | Effective emission control (BAT) | 15 | 13 | 10 | CEPMEIP (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification) |
| Conventional emission control | 100 | 70 | 55 | CEPMEIP (uncontrolled, optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification) |
| Older small uncontrolled | 600 | 350 | 210 | CEPMEIP (uncontrolled, optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification) |

Table 7.2d Emission factors for combustion processes burning natural gas

| **Fuel** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Notes** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Natural gas | 301 | Various | Electricity, CHP and heating plant | Burner with optimised combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Conventional installation | 0.2 | 0.2 | 0.2 | CEPMEIP |
| Conventional installation | 0.9 | 0.9 | 0.9 | USEPA filterable |

Table 7.2e Emission factors for combustion of derived gases

| **Fuel** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Notes** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Gas works gas | 311 | Various | Electricity, CHP and heating plant | Clean fuel, efficient combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Clean fuel, conventional installation | 0.2 | 0.2 | 0.2 | CEPMEIP (conventional installation) |
| Conventional installation | 5 | 5 | 5 | CEPMEIP (high PM due to fuel quality) |
| Other gaseous fuel | 314 | Various | Electricity, CHP and heating plant | Clean fuel, efficient combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Conventional installation | 5 | 5 | 5 | CEPMEIP |
| Coke oven gas | 304 | Various | Electricity, CHP heating plant, coke ovens | Clean fuel, efficient combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Clean fuel, conventional installation | 0.2 | 0.2 | 0.2 | CEPMEIP (conventional installation) |
| Conventional installation | 5 | 5 | 5 | CEPMEIP |
| Blast furnace gas | 305 | Various | Electricity, CHP and heating plant, coke ovens | Clean fuel, efficient combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Clean fuel, conventional installation | 0.2 | 0.2 | 0.2 | CEPMEIP (conventional installation) |
| Conventional installation | 5 | 5 | 5 | CEPMEIP |

Table 7.2f Emission factors for combustion of heavy fuel oil

| **Fuel** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Notes** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Residual fuel oil | 203 | Various | Electricity, CHP and heating plant | Low S fuel with optimised burner and abatement | 3 | 3 | 2.5 | CEPMEIP (about 10 mg·Nm-3 or BAT) |
| Low S fuel, efficient combustion | 14 | 12 | 10 | CEPMEIP (about 50 mg·Nm-3) |
| Low-medium S fuel, conventional installation | 20 | 15 | 9 | CEPMEIP (about 70 mg·Nm-3) |
| Low-medium S fuel, conventional installation | 60 | 50 | 40 | CEPMEIP (higher of two entries used. About 200 mg.N Nm-3) |
| High S fuel | 210 | 190 | 130 | CEPMEIP (lower of two entries for high S used (higher entry 240 g GJ-1 for TSP). Very high emission concentration (about 750 mg·Nm-3) |
| Petroleum coke | 110 | 1.A.1.b | Oil refineries | Conventional, multicyclone | 100 | 60 | 35 | CEPMEIP. Bit. coal factors more appropriate. |

Table 7.2g Emission factors for combustion of other liquid fuels

| **Fuel** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Notes** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Gas/diesel oil | 205 | Various | Electricity, CHP, heating plant | Optimised burner | 2 | 2 | 2 | CEPMEIP |
| Conventional burner | 5 | 5 | 5 | CEPMEIP |
| Naphtha | 210 | 1.A.1.b | Oil refineries | All units | 5 | 5 | 5 | CEPMEIP |
| Liquefied petroleum gas | 303 | Various | Electricity, CHP, heating plant | Optimised burner | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Conventional burner | 5 | 5 | 5 | CEPMEIP |
| Refinery gas | 308 | Various | Electricity, CHP, heating plant | Optimised burner | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Conventional burner | 5 | 5 | 5 | CEPMEIP |
| Other oil | 224 | Various | Electricity, CHP, heating plant | Low S fuel, optimised burner | 3 | 3 | 2.5 | CEPMEIP |
| Low S fuel, efficient combustion | 14 | 12 | 10 | CEPMEIP for residual oil. (About 50 mg·Nm-3, LCPD limit for existing plant) |
| Low-medium S fuel, conventional installation | 20 | 15 | 9 | CEPMEIP. (about 70 mg·Nm-3) |
| Low-medium S fuel, conventional installation | 60 | 50 | 40 | CEPMEIP (highest of similar entries with TSP of 35, 40, 50 and 60 used. About 200 mg.N Nm-3) |
| High S fuel | 210 | 190 | 130 | CEPMEIP, lower of two entries for high S used. (This is a very high emission concentration, about 750 mg.N Nm-3) |

Table 7.2h Emission factors for combustion of biomass

| **Fuel** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Notes** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Wood | 111 | Various | Electricity, CHP, heating plant | Modern unit with FF, < 20 mg·Nm3 TSP | 7 | 7 | 6 | TSP scaled from BAT benchmark, fractions applied based on bit. Coal |
| Older unit, < 100 mg·Nm3 TSP | 35 | 25 | 12 | TSP scaled from emission concentration, fractions based on bit. Coal |
| Uncontrolled conventional installation | 100 | 70 | 55 | CEPMEIP (uncontrolled multicyclone) |
| Conventional minimal control | 160 | 150 | 150 | CEPMEIP for conventional installation |
| Charcoal | 112 | 1.A.2.c | Chemicals | Conventional large unit with multicyclone | 100 | 60 | 35 | CEPMEIP, the use of charcoal is likely to be very rare |
|  | 400 | 100 | 35 | CEPMEIP, the use of charcoal is likely to be very rare. |
| Black liquour | 215 | 1.A.2.f | Textile and leather (pulp and paper) | Conventional installation | 160 | 150 | 150 | CEPMEIP (N.B. such a high emission concentration would apply to few, if any, plant) |
| Biogas | 309 | Various | Electricity, CHP, heating plant | Modern optimised large installation | 3 | 3 | 2.5 | (CEPMEIP, clean fuel) |
| Conventional burner | 5 | 5 | 5 | CEPMEIP |
| Modern, optimised | 20 | 15 | 10 | CEPMEIP (gasification plant) |

**Chapter B111(S2)PMv2**

***Default emission factors for use with simpler methodology (Tier 1)***

| Fuel | **Technology** | **Emission factor, g GJ-1** | | | **Notes ([[4]](#footnote-4))** |
| --- | --- | --- | --- | --- | --- |
| **TSP** | **PM10** | **PM2.5** |  |
| Hard coal, (assumes 20 % ash)  Brown coal  Other solid fuels | Pulverised coal, ESP | 30 | 20 | 9 | Based on AP-42 — assumes 20 % ash content and PM emissions from solid mineral fuels generally similar to coal |
| Pulverised coal, fluid bed, other FF | 7.4 | 7.4 | 3.7 |
| Cyclone furnace, ESP | 6.1 | 4.2 | 2.3 |
| Stoker with multicyclone | 330 | 230 | 27 |
| Pulverised coal ESP + wet limestone FGD | 6 | 6 | 5 | From CEPMEIP data (US EPA default factors for wet scrubbers are very high) |
| Natural gas |  | 0.9 | 0.9 | 0.9 | AP-42 filterable PM factor |
| Derived gases |  | 5 | 5 | 5 | CEPMEIP data, worst case for derived gases |
| Heavy fuel oil  (1 % S) | No control | 25 | 18 | 13 | Assumes 1 % sulphur as specified in the EU sulphur content of liquid fuels Directive |
| FGD | 1.5 | 1.5 | 1.5 |
| Heavy fuel oil  (3 % S) | No control | 64 | 45 | 33 | Assumes 3 % sulphur (maximum permitted in EU countries) |
| FGD | 3.8 | 3.8 | 3.7 |
| Other liquid fuels | LPG | 2.0 | 2.0 | 2.0 |  |
| Biomass | FF | 51 | 38 | 33 | AP-42 wood waste |
| ESP | 28 | 21 | 18 |

Table 8.2a Emission factors for combustion processes burning hard coal

| **Fuel** | **NAPFUE** | **NFR Codes** | **Activity description** | **Activity detail ([[5]](#footnote-5))** | **Emission factor**  **g·GJ-1** | | | **Notes ([[6]](#footnote-6))** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Hard coal** |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Bituminous coal | 101 | Various | Electricity plant, CHP plant | FGD, ESP or FF < 20 mg·Nm-3 (BAT) | 6 | 6 | 5 | CEPMEIP |
| ESP (or FF) < 50 mg·Nm-3 (LCPD) | 15 | 12 | 6 | Scaled from CEPMEIP ESP factor |
| ESP < 100 mg·Nm-3 (LCPD) | 30 | 25 | 12 | From CEPMEIP sub-bit. coal ‘high efficiency ESP’, TSP scaled to the EU LCP Directive existing plant sub 100 MWth limit |
| ESP Old/conventional < 500 mg. Nm-3 | 140 | 70 | 17 | CEPMEIP |
| Large unit with multicyclone | 100 | 60 | 35 | CEPMEIP |
| Large unit, uncontrolled or cyclone | 500 | 250 | 100 | CEPMEIP (N.B. such a high emission concentration would apply to few, if any, plant) |
| Sub-bituminous coal | 103 | Various | Electricity plant, CHP plant, heat plant | FGD, ESP or FF < 20 mg·Nm-3 (BAT) | 6 | 6 | 5 | CEPMEIP |
| ESP (or FF) < 50 mg·Nm-3 (LCPD) | 15 | 12 | 6 | Scaled from CEPMEIP ESP factor |
| ESP < 100 mg·Nm-3 (LCPD) | 30 | 25 | 12 | From CEPMEIP sub-bit. coal ‘high efficiency ESP’, TSP scaled to LCPD existing plant sub 100 MWth limit |
| ESP old/conventional  < 500 mg·Nm-3 | 140 | 70 | 17 | CEPMEIP |
| Conventional large unit with multicyclone | 100 | 60 | 35 | CEPMEIP |
| Conventional unit, uncontrolled or cyclone | 500 | 250 | 100 | CEPMEIP (N.B. such a high emission concentration would apply to few, if any, plant) |
| Coke | 107 |  |  |  |  |  |  | Coke is unlikely to be burned as primary fuel, when co-fired use the factor for the principal fuel. |

Table 8.2b Emission factors for combustion processes burning brown coal

| **Fuel** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | Reference/Comments |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Brown coal | 105 | Various | Electricity plant, CHP plant, heat plant | FGD, ESP or FF < 20 mg·Nm-3 (BAT) | 9 | 8 | 6 | CEPMEIP |
| High efficiency ESP (or FF) | 40 | 30 | 14 | CEPMEIP (N.B. such a high emission concentration would apply to few, if any, plant) |
| Conventional large unit with multicyclone | 100 | 60 | 35 | CEPMEIP (N.B. such a high emission concentration would apply to few, if any, plant) |
| Older ESP | 160 | 80 | 20 | CEPMEIP (N.B. such a high emission concentration would apply to few, if any, plant) |
| Older installation uncontrolled or cyclone | 500 | 250 | 100 | CEPMEIP (N.B. such a high emission concentration would apply to few, if any, plant) |
| Peat | 113 | Various | Electricity plant, CHP plant, heat plant | BAT/new LCPD, modern end-of-pipe abatement FGD, ESP or FF. < 30 mg·Nm3 | 9 | 8 | 6 | CEPMEIP |
| Efficient abatement LCP larger facility, < 50 mg·Nm3 | 20 | 15 | 10 | TSP scaled from LCP emission limit of 50 mg·Nm-3 |
| Efficient abatement LCP < 100 MWth, < 100 mg·Nm3 | 40 | 30 | 20 | TSP scaled from LCP emission limit of 50 mg·Nm-3 |
| Conventional technology | 120 | 40 | 20 | CEPMEIP |
| Conventional smaller, multicyclone | 300 | 40 | 20 | CEPMEIP |

Table 8.2c Emission factors for combustion processes burning other solid fuels

| **Fuel** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | Reference |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Municipal solid waste | 114 | Various | Electricity plant, CHP plant, heating plant | Effective emission control (BAT) | 15 | 13 | 10 | CEPMEIP (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification) |
| (Solid) | Conventional emission control | 100 | 70 | 55 | CEPMEIP (uncontrolled. optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification) |
| Industrial Waste | 115 | Various | Electricity, CHP, heating plant | Effective emission control (BAT) | 15 | 13 | 10 | CEPMEIP, (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification) |
| Conventional emission control | 100 | 70 | 55 | CEPMEIP (uncontrolled, optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification) |

Table 8.2d Emission factors for combustion processes burning natural gas

| **Fuel (IPCC Cat)** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Reference** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Natural gas | 301 | Various | Electricity, CHP and heating plant | Burner with optimised combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Conventional installation | 0.2 | 0.2 | 0.2 | CEPMEIP |
| Conventional installation | 0.9 | 0.9 | 0.9 | USEPA AP-42 filterable PM (all PM stated to be PM1 ) |

Table 8.2e Emission factors for combustion of derived gases

| **Fuel**  **(IPCC Cat)** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Reference** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Gas works gas | 311 | Various | Electricity, CHP and heating plant | Clean fuel, efficient combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Clean fuel, conventional installation | 0.2 | 0.2 | 0.2 | CEPMEIP (conventional installation) |
| Conventional installation | 5 | 5 | 5 | CEPMEIP (N.B. high PM due to fuel quality) |
| Other gaseous fuel | 314 | Various | Electricity, CHP and heating plant | Clean fuel, efficient combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Conventional installation | 5 | 5 | 5 | CEPMEIP |
| Coke oven gas | 304 | Various | Electricity, CHP heating plant, coke ovens | Clean fuel, efficient combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Clean fuel, conventional installation | 0.2 | 0.2 | 0.2 | CEPMEIP (conventional installation) |
| Conventional installation | 5 | 5 | 5 | CEPMEIP. |
| Blast furnace gas | 305 | Various | Electricity, CHP and heating plant, coke ovens | Clean fuel, efficient combustion | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Clean fuel, conventional installation | 0.2 | 0.2 | 0.2 | CEPMEIP (conventional installation) |
| Conventional installation | 5 | 5 | 5 | CEPMEIP. |

Table 8.2f Emission factors for combustion of heavy fuel oil

| **Fuel**  **(IPCC Cat)** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Reference** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Residual fuel oil | 203 | Various | Electricity, CHP and heating plant | Low S fuel with optimised burner or abatement | 3 | 3 | 2.5 | CEPMEIP (equivalent to about 10 mg·Nm3 or BAT) |
| Low S fuel, efficient combustion | 14 | 12 | 10 | CEPMEIP, about 50 mg·Nm3 (EU LCPD limit for existing plant) |
| Low-medium S fuel, conventional installation | 20 | 15 | 9 | CEPMEIP (equivalent. to about 70mg·Nm3. |
| Low-medium S fuel, conventional installation | 60 | 50 | 40 | CEPMEIP, the higher of two entries used about 200 mg·Nm3 |
| High S fuel | 210 | 190 | 130 | CEPMEIP, the lower of two entries for high S used. (N.B. such a high emission concentration 750 mg·Nm3 would apply to few if any plant) |
| Petroleum coke | 110 | 1.A.1.b | Oil refineries | Conventional, multicyclone | 100 | 60 | 35 | CEPMEIP, N.B the factor is very high compared to the EU LCP Directive ELVs and BAT for large furnaces. Bit. coal factors more appropriate. |

Table 8.2g Emission factors for combustion of other liquid fuels

| **Fuel**  **(IPCC Cat)** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Reference** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Gas/diesel oil | 205 | Various | Electricity, CHP, heating plant | Optimised burner | 2 | 2 | 2 | CEPMEIP |
| Conventional burner | 5 | 5 | 5 | CEPMEIP |
| Naphtha | 210 | 1.A.1.b | Oil refineries | All units | 5 | 5 | 5 | CEPMEIP |
| Liquefied petroleum gas | 303 | Various | Electricity, CHP, heating plant | Optimised burner | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Conventional burner | 5 | 5 | 5 | CEPMEIP |
| Refinery gas | 308 | Various | Electricity, CHP, heating plant | Optimised burner | 0.1 | 0.1 | 0.1 | CEPMEIP |
| Conventional burner | 5 | 5 | 5 | CEPMEIP |
| Other oil | 224 | Various | Electricity, CHP, heating plant | Low S fuel, optimised burner | 3 | 3 | 2.5 | CEPMEIP |
| Low S fuel, efficient combustion | 14 | 12 | 10 | CEPMEIP for residual oil. About 50 mg·Nm3 (LCPD limit for existing plant) |
| Low-medium S fuel, conventional installation | 20 | 15 | 9 | CEPMEIP (equivalent to about 70 mg·Nm3 |
| Low-medium S fuel, conventional installation | 60 | 50 | 40 | CEPMEIP (highest of similar entries with TSP of 35, 40, 50 and 60 used. About 200 mg·Nm-3) |
| High S fuel | 210 | 190 | 130 | CEPMEIP, lower of two entries for high S used. (N.B. this is a very high emission concentration ~750 mg·Nm3) |

Table 8.2h Emission factors for combustion of biomass

| **Fuel**  **(IPCC Cat)** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor** | | | **Reference** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Wood | 111 | Various | Electricity, CHP, heating plant | Modern, BAT unit < 20 mg·Nm3 TSP | 7 | 7 | 6 | TSP scaled from BAT benchmark, fractions applied based on bit. coal |
| Older unit, < 100 mg·Nm3 TSP | 35 | 25 | 12 | TSP scaled from emission concentration, fractions based on bit. coal |
| Uncontrolled conventional | 100 | 70 | 55 | CEPMEIP (equivalent to an uncontrolled multicyclone) |
| Charcoal | 112 | 1.A.2.c | Chemicals | Conventional large unit with multicyclone | 100 | 60 | 35 | CEPMEIP (N.B. the use of charcoal in LCP is likely to be rare |
| Black liquour | 215 | 1.A.2.f | Textile and leather (pulp and paper ?) | Conventional installation | 160 | 150 | 150 | CEPMEIP (N.B. such a high emission concentration would apply to few if any plant) |
| Biogas | 309 | Various | Electricity, CHP, Heating plant | Modern optimised large installation | 3 | 3 | 2.5 | CEPMEIP (cleaned fuel) |
| Conventional burner | 5 | 5 | 5 | CEPMEIP |
| Modern, optimised | 20 | 15 | 10 | CEPMEIP (gasification plant), seems high for gaseous fuel |
| Conventional installation | 160 | 150 | 150 | CEPMEIP (N.B. such a high emission concentration would apply to few if any plant) |

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***Default emission factors for use with simpler methodology (Tier 1)***

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Fuel** | **Technology** | **Emission factor, g·GJ-1** | | | **Notes** |
|  |  | **TSP** | **PM10** | **PM2.5** |  |
| Hard coal |  | - | - | - | Not applicable |
| Brown coal |  | - | - | - | Not applicable |
| Other solid fuels |  | - | - | - | Not applicable |
| Natural gas | Gas turbines | 0.9 | 0.9 | 0.9 | US EPA |
| Spark ignition | 18 | 18 | 18 | US EPA 2-stroke lean burn, 4-stroke lean burn is 0.04 g·GJ-1 |
| Derived gases | Gas turbine | 11 | 11 | 11 | Based on US EPA landfill gas |
| Heavy fuel oil | Diesel | 28 | 23 | 22 | US EPA factor for diesel engines |
| Other liquid fuels | Gas turbine | 2.0 | 2.0 | 2.0 | US EPA factor for PM applied to other fractions |
| Diesel | 28 | 23 | 22 | US EPA |
| Biomass | Gas turbine | 11 | 11 | 11 | Landfill gas |
| Gas turbine | 5.7 | 5.7 | 5.7 | Anaerobic digester gas |

Table 9.2a Emission factors for gas turbines combustion processes

| **Fuel** | **NAPFUE** | **NFR Codes** | **Activity description** | **Activity detail** | **Emission factor, g·GJ-1** | | | **Notes** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Natural gas |  |  |  |  | 0.9 | 0.9 | 0.9 | Sierra (234 tests), assumed all PM2.5 |
| Gas oil |  |  |  |  | 3 | 3 | 3 | Sierra (15 tests), assumed all PM2.5 |

Table 9.2b Emission factors for compression ignition combustion processes

| **Fuel**  **(IPCC Cat)** | **NAPFUE** | **NFR Code** | **Activity description** | **Activity detail** | **Emission factor**  **g·GJ-1** | | | **Reference/Comments** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  | **TSP** | **PM10** | **PM2.5** |  |
| Natural gas |  |  | Dual fuel engine, gas with HFO |  | 11 | 11 | 11 | LCP BREF, assumed all PM2.5 |
| Heavy fuel oil |  |  | Diesel engine |  | 50 | 41 | 39 | LCP BREF, ‘BAT’ US EPA profile applied |
| Diesel engine |  | < 64 | 53 | 50 | LCP BREF, US EPA profile applied, applicable to older equipment |
| Gas oil |  |  | Diesel engine | < 0.02 % S | < 26 | 21 | 20 | LCP BREF, US EPA profile |
| Diesel engine |  | < 17 | 14 | 14 | Smaller unit with diesel particulate filter, US EPA profile |

1. () Available here: <http://www.ceip.at> [↑](#footnote-ref-1)
2. () Mean random reflectance: characteristic value, which stands for a defined coal composition (modular component is e.g. vitrinite). [↑](#footnote-ref-2)
3. () The following coal classification codes cover those coals, which would fall into these subcategories (Meijer, 1995)

   |  |  |
   | --- | --- |
   | International classification codes  (UN, Geneva, 1995) | 323, 333, 334, 423, 433, 435, 523, 533, 534, 535, 623, 633, 634, 635, 723, 733, 823 |
   | USA classification | Class II group 2 ‘medium volatile bituminous’ |
   | British classification | Class 202, 203, 204, 301, 302, 400, 500, 600 |
   | Polish classification | Class 33, 34, 35.1, 35.2, 36, 37 |
   | Australian classification | Class 4A, 4B, 5. |

   [↑](#footnote-ref-3)
4. () Source: R. Stewart (2006); US EPA AP 42 (1996); CEPMEIP (2006). [↑](#footnote-ref-4)
5. () KEY: FGD: flue gas desulphurisation; ESP: electrostatic precipitator; FF: fabric filter; BAT: Best Available Techniques; LCPD: large combustion plant data. [↑](#footnote-ref-5)
6. () Sources: R. Stewart (2006); US EPA AP-42 (1996); CEPMEIP (2006). [↑](#footnote-ref-6)