Category		**Title**
NFR	1.A.1	Energy industries
SNAP	01	Combustion in energy and transformation industries
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Contents

1 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)	PM_{10}	$PM_{2.5}$	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

2 Description of sources

2.1 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, SO_2 and NO_x 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 .

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

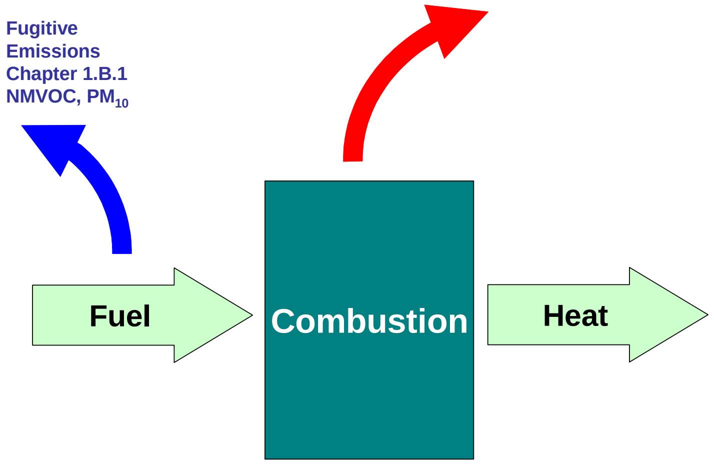


Figure 2-2 **Process scheme for power plant, adapted from IPCC Figure 2-2 in the energy industries chapter**

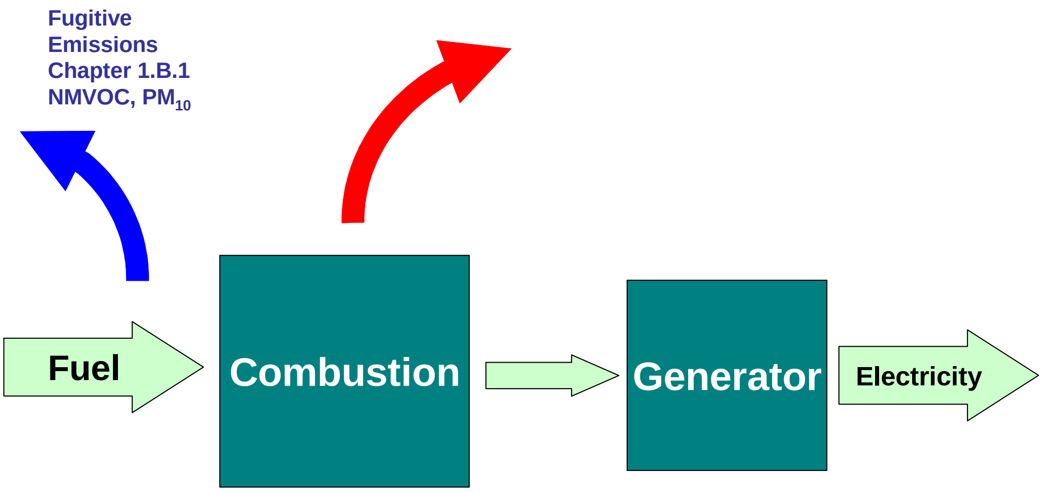
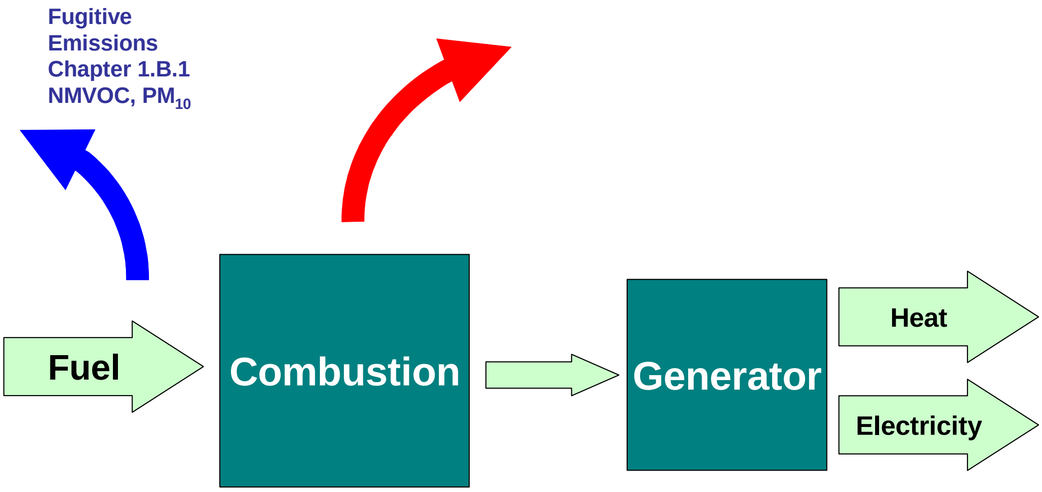


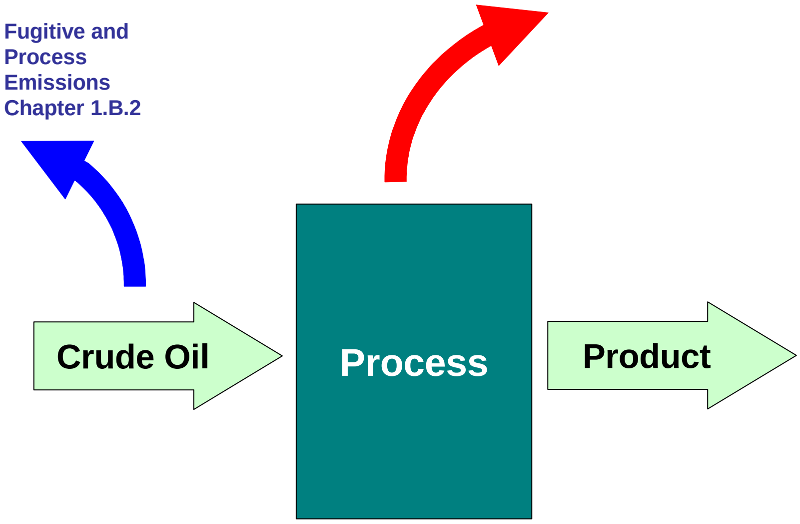
Figure 2-3 **Process scheme for combined power and heat plant, adapted from IPCC Figure 2.2 in the energy industries chapter**



2.2 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.

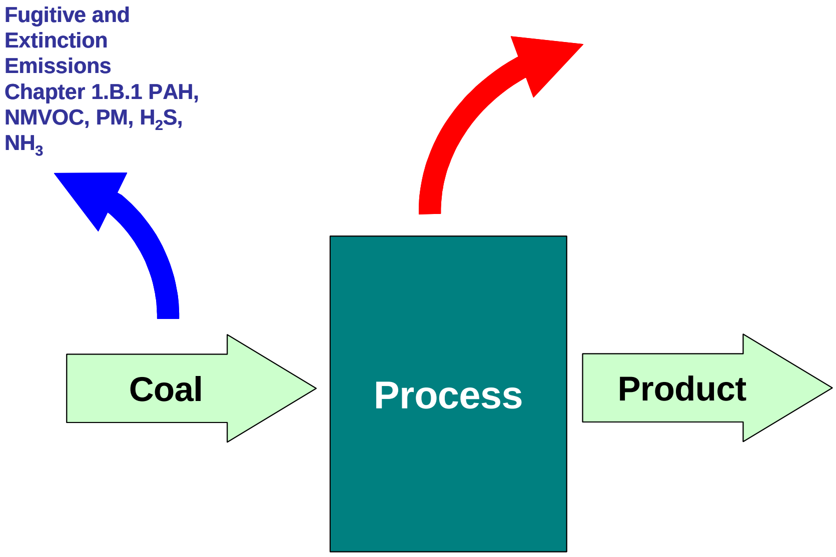
Figure 2-4 Process scheme for petroleum refinery, adapted from IPCC Figure 2-3 in the energy industries chapter



2.3 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



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

3.1 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 combustion installations https://eippcb.jrc.ec.europa.eu/sites/default/files/2019-11/JRC_107769_LCPBref_2017.pdf 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.

3.1.1 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 1200 °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 1400 °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.

3.1.2 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.

3.1.3 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.

3.1.4 Combustion of gas and oil

3.1.4.1.1 Boilers and furnaces

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

3.1.4.1.2 Gas turbines

Gas turbines are installed with a thermal capacity ranging from a few MW_{th} up to about 1000 MW_{th}. 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.

3.1.4.1.3 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, electricity grid support and standby or emergency uses.

3.2 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])

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].

([1]) Available here: http://www.ceip.at

3.2.1.1.1 Sulphur oxides

In the absence of flue gas desulphurisation (FGD) technology, the emissions of sulphur oxides (SO_x) are directly related to the sulphur content of the fuel. The sulphur content of refined natural gas is negligible. The majority of SO_x is sulphur dioxide (SO_2) although small proportions of sulphur trioxide (SO_3) can arise.

3.2.1.1.2 Nitrogen oxides

Emissions of nitrogen oxides (nitric oxide and nitrogen dioxide — NO_x) 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 NO_x emission control (low NO_x burner technology) and this may be supplemented by use of selective catalytic reduction (SCR) or selective non-catalytic reduction techniques (SNCR).

3.2.1.1.3 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 (C_2H_6) can be emitted. The relevance of NMVOC and CH_4 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 significant NMVOC and CH_4 emissions.

3.2.1.1.4 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 CO_2. 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 emissions are also possible in the case of flue gas recirculation as a primary measure for NO_X reduction.

3.2.1.1.5 Ammonia (NH_3)

Emissions of ammonia (NH_3) are not generally associated with a combustion process; emissions can result from incomplete reaction of NH_3 additive in NO_x abatement systems — selective catalytic and non-catalytic reduction (SCR and SNCR). Higher NH_3 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 NH_3 emissions can be expected.

3.2.1.1.6 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, PM_{10} and $PM_{2.5}$) 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).

3.2.1.1.7 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, $PM_{2.5}$ emission. Consequently, for inventory development, the BC emission factors are expressed as percentage of the $PM_{2.5}$ 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 $PM_{2.5}$ inventory.

3.2.1.1.8 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).

3.3 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 NO_x and SO_2 emission controls are also provided in Appendix B. Relevant abatement technologies for selected pollutants are outlined below.

3.3.1 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 SO_2 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 SO_2 with an alkaline agent added as solid or as suspension/solution of the agent in water to form the respective salts. In secondary reactions SO_3, fluorides and chlorides are also removed. In the case of some processes the SO_2 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.

3.3.1.1.1 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 SO_2 reduction efficiency is > 90 %.

3.3.1.1.2 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 SO_2 reduction efficiency is > 90 %.

3.3.1.1.3 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 $NaHCO_3$ is used in some smaller applications).

3.3.2 Nitrogen oxides

3.3.2.1.1 Primary measures

Primary measures minimise formation of NO_x in the furnace or combustion chamber and include low-NO_x 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 NO_x reduction. Modern gas turbines can achieve very low NO_x emissions by application of dry low NO_x (DLN) burner technology without secondary measures.

3.3.2.1.2 Secondary measures — DeNO$_x$ 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 NO_x. 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 NO_x reduction efficiency can be between 70 and 90 %.

3.3.3 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.

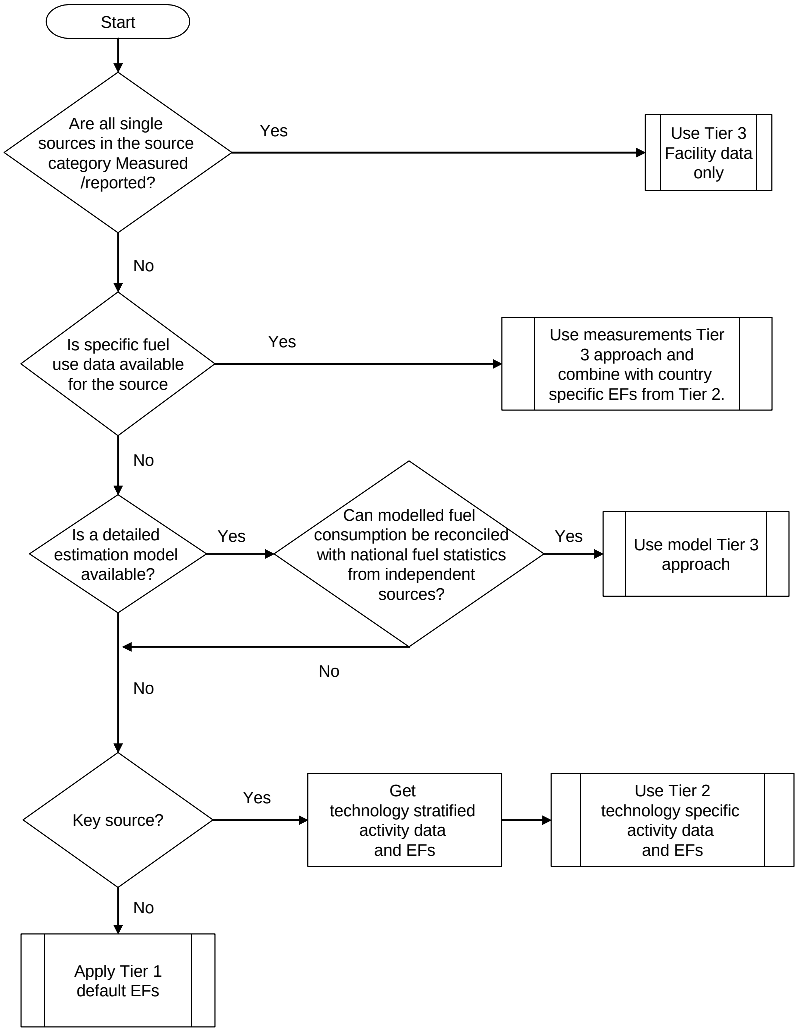
3.4 Methods

3.4.1 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



3.4.2 Tier 1 default approach

3.4.2.1 Algorithm

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

$$E_{pollutant} = AR_{fuelconsumption} \times EF_{pollutant} \quad (1)$$

$E_{pollutant}$	annual emission of pollutant
$EF_{pollutant}$	emission factor of pollutant
$AR_{fuel\ consumption}$	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 NO_x and SO_2 emission controls and abatement efficiency are provided in Appendix B.

3.4.2.2 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 3-8.

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, liquified petroleum 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
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 use of liquified petroleum gas causes usually higher NO_X emissions than the use of natural gas. But all the other pollant emissions are more similar to natural gas.

The emission factors provided in Table 3-2 to Table 3-8 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. 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 NO_x emission factors are expressed as NO_2 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 SO_2 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 SO_2 and no retention in ash.

$$EF_{SO2} = [S] \times 20,000 / CV_{Net}$$

where:

EF_{SO2} is the SO_2 emission factor (g/GJ)

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

CV_{Net} 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	NH_3				
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
PM_{10}	7.7	g/GJ	2	200	US EPA (1998), chapter 1.1
$PM_{2.5}$	3.4	g/GJ	0.9	90	US EPA (1998), chapter 1.1
BC	2.2	% of $PM_{2.5}$	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 SO$_x$ assumes no SO$_2$ 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, PM$_{10}$ and PM$_{2.5}$ 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	NH_3, 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
PM$_{10}$	7.9	g/GJ	1	79	US EPA (1998), chapter 1.7
PM$_{2.5}$	3.2	g/GJ	1	32	US EPA (1998), chapter 1.7
BC	1	% of PM$_{2.5}$	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 SO_x assumes no SO_2 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, PM_{10} and $PM_{2.5}$ 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	PCDD/F, PCBs, HCB, PAH				
Not estimated	NH_3, , BC				
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
PM_{10}	<0.14	g/GJ	<0.09	<0,19	Equal to TSP
$PM_{2.5}$	<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 SO$_x$ (for US region) is based on approximately 0.01 gm3 mass sulphur content.

The TSP, PM$_{10}$ and PM$_{2.5}$ emission factors, some of the SOx emission factors and most of the heavy metal emission factors are derived from measurement data below the limit of quantification which are marked with "<". The "<" sign gives additional information on the data quality. Nevertheless, these emission factors can be used directly for calculation.

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					
Not estimated	PM10, PM2.5, BC, NMVOC, HM, PCDD/F, PCBs, HCB, PAH, NH$_3$				
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
PM10	1.5	g/GJ	1	2	assumed to be equal to TSP
PM2.5	1.5	g/GJ	1	2	Assumed to be equal to TSP

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	NH$_3$, 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
PM$_{10}$	25.2	g/GJ	1.5	150	US EPA (2010), chapter 1.3
PM$_{2.5}$	19.3	g/GJ	0.9	90	US EPA (2010), chapter 1.3
BC	5.6	% of PM$_{2.5}$	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 SO_x assumes no SO_2 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, PM_{10} and $PM_{2.5}$ 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.

Table 3-7 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	NH_3, 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
PM_{10}	3.2	g/GJ	1	10	US EPA (1998), chapter 1.3
$PM_{2.5}$	0.8	g/GJ	0.3	2.5	US EPA (1998), chapter 1.3
BC	33.5	% of $PM_{2.5}$	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/10^3 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 SO_x assumes no SO_2 abatement and is based on 0.1 % mass sulphur content.

The TSP, PM_{10} and $PM_{2.5}$ emission factors represent filterable PM emissions. Note that condensable PM emission factors are also provided in US EPA (1998), Chapter 1.3.

Table 3-8 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	NH_3				
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
PM_{10}	155	g/GJ	77	310	US EPA (2003), chapter 1.6
$PM_{2.5}$	133	g/GJ	66	266	US EPA (2003), chapter 1.6
BC	3.3	% of $PM_{2.5}$	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, PM_{10} and $PM_{2.5}$ emission factors represent filterable PM emissions. Note that a condensable PM emission factor is also provided in US EPA (1998), Chapter 1.6.

Table 3-9 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 NH_3 are derived from just one sample. Most of the heavy metal measurement were below the limit of quantification and marked with "<". The "<" sign gives additional information on the data quality. Nevertheless, these emission factors can be used for calculations.

3.4.2.3 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]).

3.4.3 Tier 2 technology-specific approach

3.4.3.1 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

a) defining the activity data using each of the identified process types (together called ‘technologies’ in the formulae below) separately, and

b) applying technology-specific emission factors for each process type:

$$E_{pollutant} = \sum_{technologies} AR_{production,technology} \times EF_{technology,pollutant} \tag{2}$$

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.

$$\begin{aligned} EF_{country,\,pollutant} &= \sum_{technologies} Penetration_{technology} \times EF_{technology,pollutant} \\ E_{pollutant} &= AR_{production} \times EF_{country,\,pollutant} \end{aligned} \tag{3}$$

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.

3.4.3.2 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 MW_{th}) 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 3-10 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 or country specific emission factors should be used.

Table 3-11 Tier 2 emission factors for source category 1.A.1.a, dry 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	Dry Bottom Boilers				
Region or regional conditions	NA				
Abatement technologies	Abatement assumed except for SO_2 EF				
Not applicable					
Not estimated	NH_3				
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
PM_{10}	7.7	g/GJ	2	200	US EPA (1998), chapter 1.1

$PM_{2.5}$	3.4	g/GJ	0.9	90	US EPA (1998), chapter 1.1
BC	2.2	% of $PM_{2.5}$	0.27	8.08	See Note

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 SO_x assumes no SO_2 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, PM_{10} and $PM_{2.5}$ 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 3-12 Tier 2 emission factors for source category 1.A.1.a, wet and dry bottom boilers using brown coal/lignite

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, NH_3				
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
PM_{10}	7.9	g/GJ	1	79	US EPA (1998), chapter 1.7
$PM_{2.5}$	3.2	g/GJ	1	32	US EPA (1998), chapter 1.7

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 SO_x assumes no SO_2 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, PM_{10} and $PM_{2.5}$ 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 3-13 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	NH_3, 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
PM_{10}	25.2	g/GJ	1.5	150	US EPA (2010), chapter 1.3
$PM_{2.5}$	19.3	g/GJ	0.9	90	US EPA (2010), chapter 1.3
BC	5.6	% of $PM_{2.5}$	0.22	8.69	See Note

Note:

For conversion of the US EPA data the heating value as provided in the reference has been used (150 MMBTU/10^3 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 SO_x assumes no SO_2 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, PM_{10} and $PM_{2.5}$ 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 3-14 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	NH_3,				
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
PM_{10}	<0.14	g/GJ	<0.09	<0.19	UBA 2019
$PM_{2.5}$	<0.14	g/GJ	<0.09	<0.19	UBA 2019

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 SO_x is based on approximately 0.01 g/m3 mass sulphur content.

Some of the SOx, TSP, PM_{10} and $PM_{2.5}$ emission factors are below the limit of determination.

Table 3-15 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	NH_3				
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
PM_{10}	155	g/GJ	77	310	US EPA (2003), chapter 1.6
$PM_{2.5}$	133	g/GJ	66	266	US EPA (2003), chapter 1.6

BC	3.3	% of $PM_{2.5}$	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, PM_{10} and $PM_{2.5}$ emission factors represent filterable PM emissions. Note that a condensable PM emission factor is also provided in US EPA (1998), Chapter 1.6.

Table 3-16 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 SO_2				
Not applicable					
Not estimated	NH_3				
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
PM_{10}	6.0	g/GJ	6	24	US EPA (1998), chapter 1.1
$PM_{2.5}$	3.1	g/GJ	3	12	US EPA (1998), chapter 1.1
BC	2.2	% of $PM_{2.5}$	0.27	8.08	See Note

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 SO_x assumes no SO_2 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, PM_{10} and $PM_{2.5}$ 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 3-17 Tier 2 emission factors for source category 1.A.1.a, fluid bed boilers using hard coal

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 SO_2				
Not applicable					
Not estimated	NH_3				
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
PM_{10}	7.7	g/GJ	6	24	US EPA (1998), chapter 1.1
$PM_{2.5}$	5.2	g/GJ	3	12	US EPA (1998), chapter 1.1
BC	2.2	% of $PM_{2.5}$	0.27	8.08	See Note

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 SO_x assumes no SO_2 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, PM_{10} and $PM_{2.5}$ 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 3-18 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, NH_3				

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
PM_{10}	6.9	g/GJ	2.3	20.7	US EPA (1998), chapter 1.7
$PM_{2.5}$	2.8	g/GJ	0.9	8.4	US EPA (1998), chapter 1.7

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 SO_x assumes no SO_2 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, PM_{10} and $PM_{2.5}$ 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 3-19 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	PCB, PCDD/F, HCB				
Not estimated	NH_3, , BC				
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
PM_{10}	<0.2	g/GJ	<0.05	0.8	Assumed equal to TSP
$PM_{2.5}$	<0.2	g/GJ	<0.05	0.8	Assumed equal to TSP

Notes:

T3.4.2.2The basis of the TSP, PM_{10} and $PM_{2.5}$ 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 3-20 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	NH_3, 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
PM_{10}	1.95	g/GJ	0.65	5.85	US EPA (2000), chapter 3.1
$PM_{2.5}$	1.95	g/GJ	0.65	5.85	US EPA (2000), chapter 3.1
BC	33.5	% of $PM_{2.5}$	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 SO_x 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, PM_{10} and $PM_{2.5}$ emission factors represent filterable PM emissions. Note that a condensable PM emission factor is also provided in US EPA (2000), Chapter 3.1.

Table 3-21 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	NH_3				
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
PM_{10}	22.4	g/GJ	11.2	44.8	US EPA (1996), chapter 3.4
$PM_{2.5}$	21.7	g/GJ	10.8	43.4	US EPA (1996), chapter 3.4
BC	78	% of $PM_{2.5}$	63	93	Hernandez et al., 2004
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 SO_x assumes no SO_2 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, PM_{10} and $PM_{2.5}$ emission factors represent filterable PM emissions. Note that a condensable PM emission factor is also provided in US EPA (1996), Chapter 3.4.

Some POPs emission factors are derived from measurement data below the limit of quantification which are marked with “<”. The “<” sign gives additional information on the data quality. Nevertheless, these emission factors can be used directly for calculations.

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

Table 3-22 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	NH_3, PCBs, HCB				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	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
SO_2	0.5	g/GJ	0.1	1	BUWAL, 2001
TSP	2	g/GJ	1	3	BUWAL, 2001
PM_{10}	2	g/GJ	1	3	BUWAL, 2001
$PM_{2.5}$	2	g/GJ	1	3	BUWAL, 2001
BC	2.5	% of $PM_{2.5}$	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:

SO_2 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, PM_{10} and $PM_{2.5}$ 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.

Several heavy metal emission factors are derived from measurement data below the limit of quantification which are marked with “<”. The “<” sign gives additional information on the data quality. Nevertheless, these emission factors can be used directly for calculation.

3.4.3.3 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:

$$EF_{technology,abated} = (1 - \eta_{abatement}) \times EF_{technology,unabated} \tag{5}$$

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.

3.4.3.4 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.

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.

3.4.4 Tier 3 use of facility-specific data

3.4.4.1 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:

$$EF = \sum_{Facilities} E_{Facility,\,pollutant} \Bigg/ \sum_{Facilities} Production_{Facility} \tag{7}$$

- 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.

3.4.4.2 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).

3.4.4.3 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.

4 1.A.1.b Petroleum refining

4.1 Techniques

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

4.1.1 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.

4.1.2 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).

4.2 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].

4.2.1.1.1 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 (SO_x) are directly related to the sulphur content of the fuel. The majority of SO_x is sulphur dioxide (SO_2) although small proportions of sulphur trioxide (SO_3) can arise.

4.2.1.1.2 Nitrogen oxides

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

4.2.1.1.3 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).

4.2.1.1.4 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.

4.2.1.1.5 Ammonia (NH_3)

Emissions can result from incomplete reaction of NH_3 additive in NO_x 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.

4.2.1.1.6 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, PM_{10} and $PM_{2.5}$) represent total PM, filterable PM or whether the basis of the emission factor cannot be determined (see individual emission factor tables).

4.2.1.1.7 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.

4.3 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.

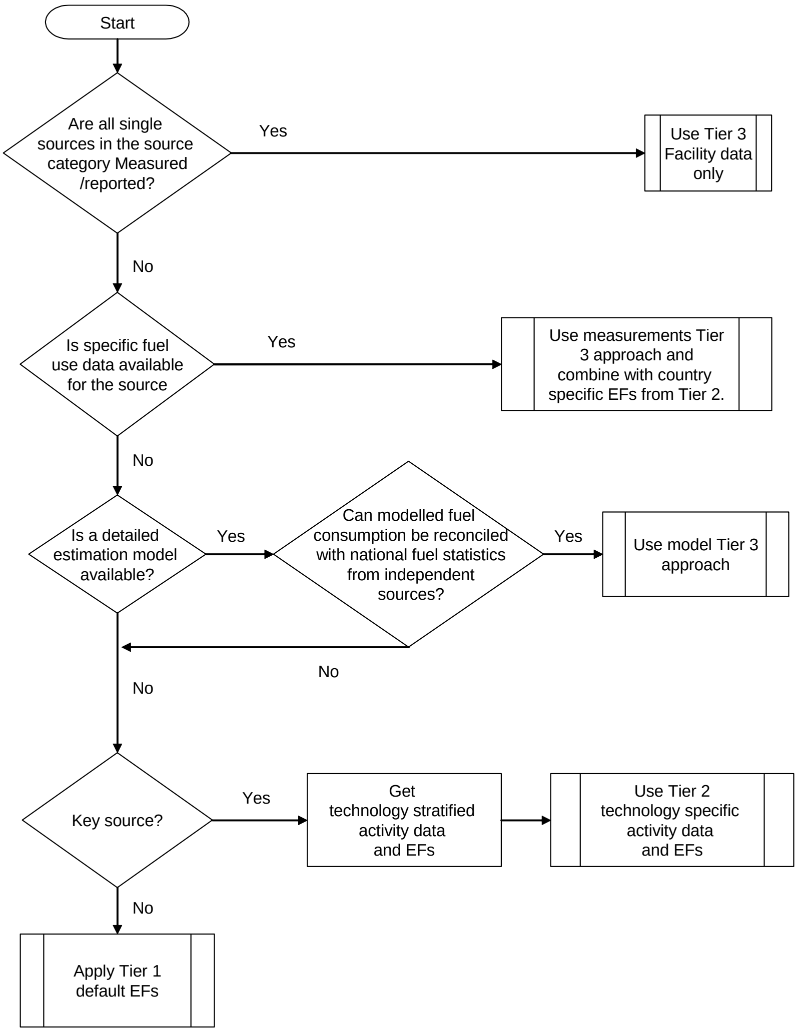
4.4 Methods

4.4.1 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



4.4.2 Tier 1 default approach

4.4.2.1 Algorithm

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

$$E_{pollutant} = AR_{fuelconsumption} \times EF_{pollutant} \qquad (1)$$

$E_{pollutant}$ annual emission of pollutant

$EF_{pollutant}$ emission factor of pollutant

$AR_{fuel\ consumption}$ 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.

4.4.2.2 Default emission factors

The default emission factors for combustion activities at Tier 1 are based on fuel consumption data from Eurostat and Tier 2 emission factors for process furnaces and heaters following the fuel classifications (see Table 4-1).

Table 4-1 Tier 1/ Tier 2 fuel classifications

Tier 1/ Tier 2 fuel type	**Associated fuel types**
Refinery gas	**Refinery gas**
Natural gas	Natural gas, natural gas liquids
Residual oil	Residual fuel oil, refinery feedstock, petroleum coke
Gas oil	Gas oil, kerosene, naphtha, liquefied petroleum gas, orimulsion, shale oil

The calculated emission is divided by the crude oil input given by Eurostat (refinery intake).

For countries where fuel consumption data are available it's better using the Tier 2 emission factors for process furnaces, heaters and boilers directly. This is a more accurate calculation. Even if the amount of fuel used in gas turbines or engines is unkown.

Table 4-2 Tier 1 emission factors for source category 1.A.1.b all fuels

Tier 1 default emission factors					
	Code	Name			
NFR Source Category	1.A.1.b	Petroleum Refining			
Fuel					
Not applicable					
Not estimated	HCB, PCB				
Included elsewhere	NMVOC (1.B.2.a.iv)				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NOx	0.2218	kg/ Mg crude oil input	0.1109	0.3422	1)
CO	0.0545	kg/ Mg crude oil input	0.0326	0.0776	1)
SOx (other regions)	0.375	kg/ Mg crude oil input	0.21	1.9	2)
SOx (EU-region)	0.2496	kg/ Mg crude oil input	0.0787	0.8542	1)
TSP	0.0113	kg/ Mg crude oil input	0.0063	0.0191	1)
PM_{10}	0.0088	kg/ Mg crude oil input	0.0049	0.0151	1)
$PM_{2.5}$	0.0059	kg/ Mg crude oil input	0.0031	0.0106	1)
BC	0.0008	kg/ Mg crude oil input	0.0001	0.0028	1)

NH_3	0.0008	kg/ Mg crude oil input	0.0002	0.0036	3)
Pb	0.0049	g/ Mg crude oil input	0.0024	0.0147	1)
Cd	0.0041	g/ Mg crude oil input	0.0011	0.0091	1)
Hg	0.0008	g/ Mg crude oil input	0.0004	0.0020	1)
As	0.0026	g/ Mg crude oil input	0.0009	0.0105	1)
Cr	0.0178	g/ Mg crude oil input	0.0019	0.0563	1)
Cu	0.0110	g/ Mg crude oil input	0.0050	0.0353	1)
Ni	0.3796	g/ Mg crude oil input	0.3104	0.4492	1)
Se	0.0038	g/ Mg crude oil input	0.0020	0.0111	1)
Zn	0.0508	g/ Mg crude oil input	0.0240	0.1529	1)
Benzo(a)pyrene	0.0011	mg/ Mg crude oil input	0.0004	0.0032	1)
Benzo(b)fluoranthene	0.0036	mg/ Mg crude oil input	0.0010	0.0143	1)
Benzo(k)fluoranthene	0.0010	mg/ Mg crude oil input	0.0003	0.0030	1)
Indeno(1,2,3-cd)pyrene	0.0010	mg/ Mg crude oil input	0.0003	0.0030	1)
PCDD/F	0.0012	µg/ Mg crude oil input	0.0006	0.0018	1)

Note 1) For the calculation of the Tier 1 emission factors for EU-region 2021 Eurostat fuel consumption data are used for EU27. These data were multiplied with Tier 2 emission factors for process heaters and boilers. The calculated emissions were divided by the crude oil input of all EU27 countries derived from Eurostat 2021. The average fuel mix in 2021 was: 55% refinery gas, 16% residual oil, 1% gas oil and 27% natural gas (refered to energy units). These Tier 1 emission factors for the EU-region reflect the implementation of the BAT conclusions in 2014. Therefore the use of these emission factors is only appropriate for countries with a similar emission standard.

2) The SO_X Tier 1 EF for other regions is derived from emissions reported by EU-27 to E-PRTR for the year 2010 divided by the amount of 'Transformation input in Refineries' in 2010 provided by Eurostat (Supply, transformation, consumption - oil - annual data [nrg_102a]). Therafter the SO_X emission factor from process emissions in chapter 1.B.2.a.iv is subtracted in order to avoid double-counting.

3) Ammonia emission factors are derived from EU-27 E-PRTR emission data of the year 2021 divided by the crude oil input (refinery intake) provided by Eurostat 2021. However, the data quality is very low since Ammonia is usually not measured and only 4 countries are reporting Ammonia emissions.

Emissions from catalytic cracking units (FCCU) and catalytic reforming units (CRU) are not included in the Tier 1 emission factors. For this processes Tier 1 emission factors are available in chapter 1.B.2.a.iv. Sulphur recovery plants are also not included in the 1.A.1.b Tier 1 emission factors. For sulphur recovery plants only Tier 2 emission factors are available in chapter 1.B.2.a.iv.

Regarding NMVOC a distinction between combustion and fugitive emissions cannot be made. Since most of the NMVOC emissions are fugitive they were allocated to 1.B.2.a.iv in order to avoid double-counting. The Tier 1 emission factor in 1.B.2.a.iv is derived from E-PRTR data which is a sum of all refinery emission sources.

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.

4.4.2.3 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). For Eurpean countries this data can be taken from Eurostat.

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.

4.4.3 Tier 2 technology-specific approach

4.4.3.1 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:

$$E_{pollutant} = \sum_{technologies} AR_{production,technology} \times EF_{technology,pollutant} \qquad (2)$$

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:

$$EF_{country,pollutant} = \sum_{technologies} Penetration_{technology} \times EF_{technology,pollutant}$$
$$E_{pollutant} = AR_{production} \times EF_{country,pollutant} \qquad (3)$$

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.

4.4.3.2 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 NO_x emissions has been provided in Concawe, 2015 as the sector's recommended method for refineries to use for emission reporting. However, NO_x 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	Refinery gas	Table 4.4
	Residual oil	Table 4-6
	Gas oil	Table 4-7
	Natural gas	Table 4-9
Gas turbines	Various	See Section 1.A.1.a
Gas engines	Natural gas	Table 4.9
Compression ignition engines	Gas oil	Table 4.10

In order to avoid double-counting with source category 1.B.2.a.iv, all fuel related NMVOC emission factors were set IE. In the case that a country is using a country-specific method to determine NMVOC emissions in 1.B.2.a.iv which considers only fugitive emissions, the following NMVOC emission factors have to be used for process furnaces, heaters and boilers:

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

Tier 2 default emission factors					
	Code	Name			
NFR Source Category	1.A.1.b	Petroleum refining			
Fuel	Refinery Gas				
SNAP (if applicable)	0103 Petroleum refining plants				
Technologies/Practices	Process Furnaces, Heaters and Boilers				
Not applicable					
Not estimated	NH3, PCDD/F, HCB				
Included elsewhere	NMVOC (1.B.2.a.iv)				
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)
SOx	10.44	g/GJ	4.79	16.09	UBA 2023
TSP	0.89	g/GJ	0.297	2.67	US EPA (1998), chapter 1.4
PM_{10}	0.89	g/GJ	0.297	2.67	US EPA (1998), chapter 1.4
$PM_{2.5}$	0.89	g/GJ	0.297	2.67	US EPA (1998), chapter 1.4
BC	18.4	% of $PM_{2.5}$	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 SO_x is based on measurement data from all German refineries in 2016 (see subsection 3.4.2.2).

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

Table 4-5 NMVOC Tier 2 default factors for source category 1.A.1.b, residual oil, gas oil, and natural gas

Tier 2 emission factors					
fuel	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
Residual oil	2.3	g/GJ	0.676	4.09	US EPA (1998), chapter 1.3
Gas oil	0.65	g/GJ	0.22	1.95	US EPA (1998), chapter 1.3
Natural gas	2.58	g/GJ	1.29	5.16	US EPA (1998), chapter 1.4

For gas turbines and engines NMVOC emission factors are provided in chapter 1.A.1.a.

Table 4-6 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	NH_3, Benzo(a)pyrene, Benzo(k)fluoranthene, Indeno(1,2,3-cd)pyrene, PCBs, HCB				
Included elsewhere	NMVOC (1.B.2.a.iv)				
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)
SOx	485	g/GJ	146	1700	See Note
TSP	20	g/GJ	12	28	Visschedijk et al (2004)
PM_{10}	15	g/GJ	9	21	Visschedijk et al (2004)
$PM_{2.5}$	9	g/GJ	5.4	12.6	Visschedijk et al (2004)
BC	*5.6*	*% of $PM_{2.5}$*	*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 SO_x assumes no SO_2 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 4-7 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	NH$_3$, PCDD/F, Benzo(a)pyrene, *Benzo(b)fluoranthene,* Benzo(k)fluoranthene, Indeno(1,2,3-cd)pyrene, PCBs, HCB				
Included elsewhere	NMVOC (1.B.2.a.iv)				
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
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
PM$_{10}$	3.23	g/GJ	0.647	16.2	US EPA (1998), chapter 1.3
PM$_{2.5}$	0.808	g/GJ	0.162	4.04	US EPA (1998), chapter 1.3
BC	33.5	% of PM$_{2.5}$	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 4-8 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	NH_3, BC				
Included elsewhere	NMVOC (1.B.2.a.iv)				
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
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
PM_{10}	<0.14	g/GJ	<0.09	<0.19	UBA 2019
$PM_{2.5}$	<0.14	g/GJ	<0.09	<0.19	UBA 2019
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

Note:

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).

Several heavy metal emission factors are derived from measurement data below the limit of quantification which are marked with "<". The "<" sign gives additional information on the data quality. Nevertheless, these emission factors can be used directly for calculations.

Table 4-9 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					
Not estimated	NH_3, PCBs, HCB				
Included elsewhere	NMVOC (1.B.2.a.iv)				
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;
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;
PM_{10}	0.037	g/GJ	0.003	0.37	US EPA (2000), chapter 3.2;
$PM_{2.5}$	0.037	g/GJ	0.003	0.37	US EPA (2000), chapter 3.2;
BC	2.5	% of $PM_{2.5}$	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
PCDD/F	0.57	ng I-TEQ/GJ	0.28	1.2	Nielsen et al., 2010
Benzo(a)pyrene	1.2	µg/GJ	0.24	6	Nielsen et al., 2010
Benzo(b)fluoranthene	9.0	µg/GJ	1.8	45	Nielsen et al., 2010
Benzo(k)fluoranthene	1.7	µg/GJ	0.34	8.5	Nielsen et al., 2010
Indeno(1,2,3-cd)pyrene	1.8	µg/GJ	0.36	9	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. Several heavy metal emission factors are derived from measurement data below the limit of quantification which are marked with “<”. The “<” sign gives additional information on the data quality. Nevertheless, these emission factors can be used directly for calculations.

The factor for SO_x is based on approximately 0.01 gm^3 mass sulphur content. SO_2 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 4-10 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	NH_3				
Included elsewhere	NMVOC (1.B.2.a.iv)				
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
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
PM_{10}	22.4	g/GJ	11.2	44.8	US EPA (1996), chapter 3.4
$PM_{2.5}$	21.7	g/GJ	10.8	43.4	US EPA (1996), chapter 3.4
BC	78	% of $PM_{2.5}$	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 SO_x assumes no SO_2 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)

4.4.3.3 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

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.

4.4.4 Tier 3 use of facility-specific data

4.4.4.1 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:

$$EF = \sum_{Facilities} E_{Facility,\,pollutant} \Big/ \sum_{Facilities} Production_{Facility} \qquad (7)$$

- 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.

4.4.4.2 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).

4.4.4.3 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.

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

5.1 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.

5.2 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].

5.2.1.1.1 Sulphur oxides

Emissions arise from combustion of coke oven gas (COG). Gas is treated to removed H_2S but residual H_2S is oxidised to form SO_2.

5.2.1.1.2 Nitrogen oxides

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

5.2.1.1.3 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.

5.2.1.1.4 Carbon monoxide (CO)

Emissions arise from combustion activities and fugitive release of COG.

5.2.1.1.5 Particulate matter

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

5.3 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 SO_2 emission is by removal of H_2S and other sulphurous material from the fuel gas.

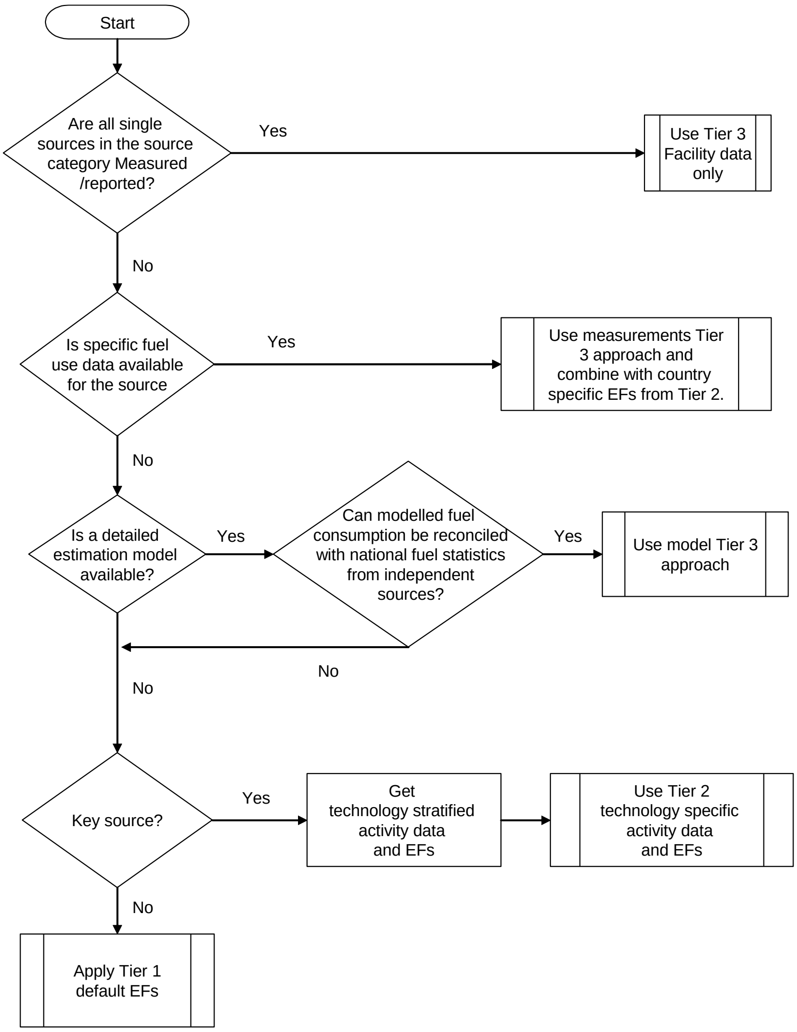
5.4 Methods

5.4.1 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



5.4.2 *Tier 1 default approach*

5.4.2.1 Algorithm

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

$$E_{pollutant} = AR_{fuelconsumption} \times EF_{pollutant} \qquad (1)$$

where

$E_{pollutant}$ = annual emission of pollutant

$EF_{pollutant}$ = emission factor of pollutant

$AR_{fuel\ consumption}$ = 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.

5.4.2.2 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	NH_3,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
PM_{10}	79	g/GJ	40	160	See note
$PM_{2.5}$	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, PM_{10} and $PM_{2.5}$ emission factors could not be determined in the reference.

5.4.2.3 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]).

5.4.3 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
PM$_{10}$	1864	g/Mg Coal	932	3728	US EPA (2008), chapter 12.2
PM$_{2.5}$	1176	g/Mg Coal	588	2352	US EPA (2008), chapter 12.2
BC	48	% of PM$_{2.5}$	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, PM$_{10}$ and PM$_{2.5}$ 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, NH_3, 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
PM_{10}	2618	g/Mg Coal	1309	5236	US EPA (2008), chapter 12.2
$PM_{2.5}$	1913	g/Mg Coal	957	3826	US EPA (2008), chapter 12.2
BC	48	% of $PM_{2.5}$	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, PM_{10} and $PM_{2.5}$ 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).

5.4.4 Tier 3 use of facility-specific data

5.4.4.1 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:

$$EF = \sum_{Facilities} E_{Facility,\,pollutant} \Big/ \sum_{Facilities} Production_{Facility} \qquad (7)$$

- 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.

5.4.4.2 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).

5.4.4.3 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.

6 Data quality

6.1 Completeness

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

6.2 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).

6.3 Verification

6.3.1 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 O_2 content,	AEL concentration range, mg.m-3 at STP (0ºC, 101.3 kPa) dry at reference O_2 content		Emission factor, $g \cdot GJ^{-1}$ (net thermal input)	
			MW_{th}	%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	
NO_x	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

Pollutant	Fuel type [1]	New or existing plant [2]	Boiler size or technology,	Reference O_2 content,	AEL concentration range, mg.m-3 at STP (0ºC, 101.3 kPa) dry at reference O_2 content		Emission factor, $g·GJ^{-1}$ (net thermal input)	
			MW_{th}	%v/v dry	Low	High	Low	High
	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
SO_2	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 O_2 content,	AEL concentration range, mg.m^{-3} at STP (0°C, 101.3 kPa) dry at reference O_2 content		Emission factor, g·GJ^{-1} (net thermal input)	
			%v/v dry	Low	High	Low	High
Whole Refinery	SO_2	daily	3	60	850	17	241
		monthly	3	100	1200	28	340
		yearly	3	1000	1400	283	396
	NO_x	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
	NO_x	-	3	100	500	28	142
No CO boiler	CO	-	3	50	100	14	28
(O_2 control)	NO_x	-	3	300	600	85	170
SCR/SNCR	NO_x	-	3	40	150	11	43
	TSP	-	3	10	50	3	14
FGD/low S	SO_2	-	3	10	350	3	99

The BAT document for coke ovens indicates that use of desulphurised coke oven gas and low-NO_x techniques represent BAT in new or modern plant. Post-desulphurisation H_2S levels of 500–1 000 mg.m^{-3} of fuel are indicated. However, further information is needed to calculate an emission factor; an estimated SO_2 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 NO_x are 140–220 g·GJ^{-1}.

6.3.2 Fuel sulphur content

For processes without SO_2 abatement, the sulphur content of the fuel provides a means to calculate the SO_2 emission factor.

$$EF_{SO2} = \frac{[S] \times 20{,}000}{CV}$$

where:

EF_{SO2} is the SO_2 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 SO_2 to sulphur

This equation can be extended to include a factor for retention of SO_2 in ash.

Liquid fuels in the EC are subject to sulphur limits (EC SCOLF, 1999/2005) as summarised in Table 6-3. The SO_2 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	SO_2 emission factor, $g \cdot GJ^{-1}$	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 43.4 $GJ.tonne^{-1}$
	Post 1.1.2008	0.1 %	46	

6.3.3 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 .

6.3.4 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.

6.4 Developing a consistent time series and recalculation

The emissions of non-CO_2 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.

6.5 Uncertainty assessment

6.5.1 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.

6.5.2 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.

6.6 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.

6.7 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.

6.8 Reporting and documentation

No specific issues.

7 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) of vitrinite of at least 0.6. Hard coal comprises the subcategories coking coal and steam coal (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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(2) Mean random reflectance: characteristic value, which stands for a defined coal composition (modular component is e.g. vitrinite).

(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.

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9 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/) for the contact details of the current expert panel leaders.

Annex A Summary of combustion plant and NFR codes

Table AA-1: Combustion plant and sector codes

	Combustion plants as point and area sources										
NFR CODE	SNAP97 Codes	NOSE CODE	Thermal capacity ［MW$_{th}$］	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	≥ 300	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				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	≥ 50 and < 300	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				x					
1.A.1.c	01 05 02	101.02				x					
1.A.4.a	02 01 02	101.02					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	< 50	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				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	not relevant							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								x	
1.A.1.c	01 05 04	101.04								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

	Combustion plants as point and area sources										
NFR CODE	SNAP97 Codes	NOSE CODE	Thermal capacity [MW_{th}]	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.c	01 04 05	101.05	not relevant								x
1.A.1.c	01 05 05	101.05									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.

Annex B 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 (SO_x) 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 (FeS_2), 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 SO_x formation.

For nitric oxide (NO, together with NO_2 normally expressed as nitrogen oxides NO_x), three different formation mechanisms are relevant:

- formation of ‘fuel-NO’ from the conversion of chemically-bound nitrogen in the fuel (NO_{fuel});
- formation of ‘thermal-NO’ from the fixation of atmospheric nitrogen coming from the combustion air ($NO_{thermal}$);
- 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 NO_x emissions from coal combustion (80 to more than 90 %) is formed from fuel nitrogen. Depending on combustion temperatures, the portion of thermal- NO_x 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 (CH_4) can be emitted. The relevance of NMVOC/CH_4 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 (NH_3) are not caused by a combustion process; the emissions result from incomplete reaction of NH_3 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 SO_2, NO_x 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 SO_x and NO_x are summarised in Tables B1–B3.

Sulphur oxides: flue gas desulphurisation (FGD) processes

FGD processes are designed to remove SO_2 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 SO_2 with an alkaline agent added as solid or as suspension/solution of the agent in water to form the respective salts. In secondary reactions SO_3, fluorides and chlorides are also removed. In the case of the DESONOX process, the SO_2 is catalytically oxidised to SO_3 and reacts with water to form sulphuric acid. The activated carbon process and the Wellman-Lord process remove the SO_2 to produce a SO_2 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 SO_2 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 MW_{th}. 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 NO_x 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 NO_x 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 NO_x reduction is also lower. The NO_x 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 NO_x 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 NO_x 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-NO_x abatement. The influence on dry bottom boilers is thus very limited, considering the fact that about 80 % of the NO_x 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 NO_x 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 NO_x combustion techniques for the primary fuels. When nitrogen is present in the reburning fuel, a part of it will be converted into NO_x in the burn-out zone. Therefore, use of natural gas provides the largest potential reduction. Trials on large boilers indicate NO_x 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 SO_2 and NO_x 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. NO_2 is completely reduced to N_2; NO reacts catalytically with the ammonia injected and forms N_2 and H_2O. 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 SO_2 reduction efficiency is > 95 %, the NO_x 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 (NO_x) to nitrogen (N_2) and water (H_2O) and on the catalytic oxidation of sulphur dioxide (SO_2) to sulphur trioxide (SO_3). 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 SO_2 reduction efficiency is up to 95 %, the NO_x 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 $DeNO_x$-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 $DeNO_x$-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 ($HgCl_2$) 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 NO_x emissions are of most relevance. Primary measures for NO_x 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 NO_x, CO and unburned hydrocarbons (VOC). For diesel engines sulphur dioxide (SO_2) 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 NO_x 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 η_{sec} [ ]	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 $DeNO_x$ process)
DESONOX – combined FGD and $DeNO_x$ process.

Table B2 NO$_x$ primary abatement measure efficiencies

Type of primary measure[1]	Reduction efficiency DBB η [ ]				Reduction efficiency WBB η [ ]	
	Hard coal		Lignite		Hard coal	
	range	value[3]	range	value[3]	range	value[3]
no measure[4]	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/retrofitted[2]	0.50		0.50		0.50	
new installation[2]	0.40		0.40		0.40	

Note:

1) Selection from the DECOF database developed by and available at the Institute for Industrial Production (IPP)
2) Recommended values, when no information concerning the type of primary measure is available
3) Default values used in the computer programme
4) No primary measures are installed. This case is mainly relevant for old installations.

Table B3 NO_x 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

Annex C 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	value[1]	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 – 0.45[10]	wt.-% (maf)
	Coke	hc	coke oven	107		< 1[3]	wt.-% (maf)
		bc	coke oven	108		0.5 – 1 [3] [4]	wt.-% (maf)
			petroleum	110			
	Biomass		wood	111		< 0.03[3]	wt.-% (maf)
			charcoal	112		< 0.03[3]	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	0.3[8]	0.08 – 1.0	wt.-%
			diesesl	205	0.3[8]		wt.-%
	kerosene			206			
	gasoline		motor	208		< 0.05[9]	wt.-%
	naphtha			210			
	black liquour			215			
Gas	Gas[2]		natural	301	0.0075[7]		$g \cdot m^{-3}$
	Gas		liquified petroleum gas	303	-		
			coke oven	304	8		$g \cdot m^{-3}$
			blast furnace	305	$45 \cdot 10^{-3}$ [7]		$g \cdot m^{-3}$
			coke oven and blast furnace	306			
			waste	307			
			refinery	308		≤ 8 [7]	$g \cdot m^{-3}$
			biogas	309			
			from gas works	311			

Notes:

1) Recommended value
2) Only trace amounts
3) Marutzky 1989
4) Boelitz 1993
5) Mr. Hietamäki (Finland): personal communication
6) Referring to NL-handbook 1988/99/ the range is 2.0 – 3.5
7) NL-handbook 1988
8) 87/219 CEE 1987
9) $a_s \sim 0$
10) Davids 1986

Annex D Emission factors derived from emission limit values

Table D1 TSP

Source [1]	Fuel type [2]	New or existing plant [3]	Boiler size or technology, MW_{th}	Reference O_2 content, %v/v dry	AEL or ELV concentration, mg.m-3 at STP (0°C, 101.3 kPa) dry at reference O_2 content		Emission factor[4], $g{\cdot}GJ^{-1}$ (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:

1) BREF denotes the large combustion plant BAT reference document, LCPD denotes Directive 2001/80/EC.
2) 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.
3) Note that new and existing plant have specific meanings under LCPD.
4) 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, MW$_{th}$	Reference O_2 content, %v/v dry	AEL or ELV concentration, mg NO_2.m^{-3} at STP (0ºC, 101.3 kPa) dry at reference O_2 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 :

1) BREF denotes the large combustion plant BAT reference document, LCPD denotes Directive 2001/80/EC, Goburg denotes the Gothenburg protocol of 1999.
2) 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.
3) Note that new and existing plant have specific meanings under LCPD.
4) 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, MW_{th}	Reference O_2 content, %v/v dry	AEL or ELV concentration, $mg.m^{-3}$ at STP (0ºC, 101.3 kPa) dry at reference O_2 content		Emission factor [4], $g^{\cdot}GJ^{-1}$ (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 :

1) BREF denotes the large combustion plant BAT reference document, LCPD denotes Directive 2001/80/EC, Goburg denotes the Gothenburg protocol of 1999.
2) 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.
3) Note that new and existing plant have specific meanings under LCPD.
4) 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 O_2 content, %v/v dry	Pollutant	AEL or ELV concentration, mg.m^{-3} at STP (0ºC, 101.3 kPa) dry at reference O_2 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	SO_2	10		8.6	
BREF	gas	existing	GT	15	SO_2	10		8.6	
BREF	gas	new	GT	15	NO_x	20	50	17.2	43.0
LCPD	gas	new	GT	15	NO_x	50	75	43.0	64.4
LCPD	oil	new	GT	15	NO_x	120		103.0	
Goburg	gas	new	GT	15	NO_x	50	75	43.0	64.4
Goburg	oil	new	GT	15	NO_x	120		103.0	
BREF	gas	existing	GT	15	NO_x	20	90	17.2	77.3
Goburg	gas	existing	GT	15	NO_x	150		128.9	
Goburg	oil	existing	GT	15	NO_x	200		171.7	
BREF	gas	new	Gas engine	15	NO_x	20	75	17.2	64.4
Goburg	gas	new	Gas engine	5	NO_x	250	500	79.7	159.4
BREF	gas	existing	Gas engine	15	NO_x	20	100	17.2	85.9
Goburg	gas	new	CI Engine	5	NO_x	500		159.4	
Goburg	oil	new	CI Engine	5	NO_x	500	600	159.3	191.1

Notes :

1) BREF denotes the large combustion plant BAT reference document, LCPD denotes Directive 2001/80/EC, Goburg denotes the Gothenburg protocol of 1999.
2) 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.
3) Note that new and existing plant have specific meanings under LCPD.
4) Emission factors calculated from emission concentrations using USEPA methodology (See Appendix E for details).

Annex E 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 % O_2
- solid-fuel boilers — 6, 7 % O_2
- wood-fired boilers — 6, 10, 11 or, 13 % O_2
- incineration — 11 % O_2
- gas turbines — 15 % O_2
- stationary engines — 5, 15 % O_2
- dryers — 17 % O_2

Other normalisation oxygen concentrations are used including 0 % O_2 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.

$$[X]_d = [X]_w \cdot \frac{100}{(100-[H_2O])}$$

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);

$[H_2O]$ 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:

$$[X]_m = [X]_d \cdot \frac{MW}{22.4}$$

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 SO_2);

22.4 is the volume occupied by 1 kgmole of an ideal gas at 0 °C, 101.3 kPa (m^3);

Note that NO_x emission concentrations and emission factors are defined in terms of NO_2. Hence, the relative molecular mass used for NO_x 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 C_3H_8 'equivalents' would be 3 x 12 = 36).

Normalisation to a reference O_2 concentration is given by :

$$[X]_{ref} = [X]_m \cdot \frac{(20.9-[O_2]_{ref})}{(20.9-[O_2]_m)}$$

where :

$[X]_{ref}$ is the standardised concentration of the pollutant at the reference O_2 content;

$[x]_m$ is the measured concentration in mg.m^{-3} for a dry flue gas;

$[O_2]_m$ is the measured O_2 concentration in % on a dry basis;

$[O_2]_{ref}$ is the reference O_2 concentration in % on a dry basis (for example 3, 6 or 15 %).

This calculation is appropriate where pollutant and O_2 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 O_2 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.

$$C_XH_Y \quad + (X+(Y/4)O_2 = X\ CO_2 + (Y/2)\ H_2O$$

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 ($DFGV_{SC}$) per unit mass of fuel (or volume for gaseous fuels) can be calculated and hence the dry flue gas volume at the normalised condition ($DFGV_{ref}$) for the required reference oxygen content:

$$DFGV_{ref} = \quad DFGV_{SC} . (20.9/(20.9-[O_{2ref}]))$$

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:

$$EF \quad = \quad [X]_{15\ \%} . DFGV_{15}$$

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.

$$EF_{thermal} = \frac{EF}{CV}$$

where:

$EF_{thermal}$ 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 and the F-factors are provided below.

Fuel type	Fd 1)		Fw 1)		Fc 1)	
	dscm/J	dscf/10^6 Btu	wscm/J	wscf/10^6 Btu	scm/J	scf/10^6 Btu
Coal						
Anthracite[2]	$2.71\cdot10^{-7}$	10100	$2.83\cdot10^{-7}$	10540	$0.530\cdot10^{-7}$	1970
Bituminus[2]	$2.63\cdot10^{-7}$	9780	$2.86\cdot10^{-7}$	10640	$0.484\cdot10^{-7}$	1800
Lignite	$2.65\cdot10^{-7}$	9860	$3.21\cdot10^{-7}$	11950	$0.513\cdot10^{-7}$	1910
Oil 3)	$2.47\cdot10^{-7}$	9190	$2.77\cdot10^{-7}$	10320	$0.383\cdot10^{-7}$	1420
Gas						
Natural	$2.34\cdot10^{-7}$	8710	$2.85\cdot10^{-7}$	10610	$0.287\cdot10^{-7}$	1040
Propane	$2.34\cdot10^{-7}$	8710	$2.74\cdot10^{-7}$	10200	$0.321\cdot10^{-7}$	1190
Butane	$2.34\cdot10^{-7}$	8710	$2.79\cdot10^{-7}$	10390	$0.337\cdot10^{-7}$	1250
Wood	$2.48\cdot10^{-7}$	8710	-	-	$0.492\cdot10^{-7}$	1830
Wood bark	$2.58\cdot10^{-7}$	9240	-	-	$0.516\cdot10^{-7}$	1920
Municipal	$2.57\cdot10^{-7}$	9600	-	-	$0.488\cdot10^{-7}$	1820
Solid waste	-	9570				

Notes:

1) determined at standard conditions: 20°C (68°F) and 760mmHg (29.92 in·Hg)
2) as classified according to ASTM D 388
3) Crude, residual or distillate

The F_d factors are used — these represent the dry stoichiometric flue gas volume per unit of energy input. The F_w and F_c factors represent the wet flue gas volume and CO_2 volumes respectively.

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

$F_d' = F_d \cdot (273/293) \cdot ((CV_{gross})/CV_{net}))$

Where :

F_d' is the stoichiometric dry flue gas volume at STP per unit of net energy input – $m^3 \cdot J^{-1}$

F_d 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	**CV_{gross}**	**CV_{net}**	**Unit**	**Ratio gross/net**
Power stn coal	26.2	24.9	$GJ\cdot tonne^{-1}$	1.05
Industrial coal	26.6	25.3	$GJ\cdot tonne^{-1}$	1.05
Wood	11.9	10	$GJ\cdot tonne^{-1}$	1.08
HFO	43.3	41.2	$GJ\cdot tonne^{-1}$	1.05
Gas oil	45.6	43.4	$GJ\cdot tonne^{-1}$	1.05
Natural gas	39.8	35.8	$MJ\cdot m^{-3}$	1.11

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

$F_{dref} = F_d' \cdot (20.9/(20.9-[O_{2ref}]))$

A pollutant emission factor ($EF_{thermal}$) 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:

$EF_{thermal} = [X]_{15\ \%} \cdot F_{d15\ \%}$

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.

$EF = EF_{thermal} \cdot CV$

where:

$EF_{thermal}$ 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

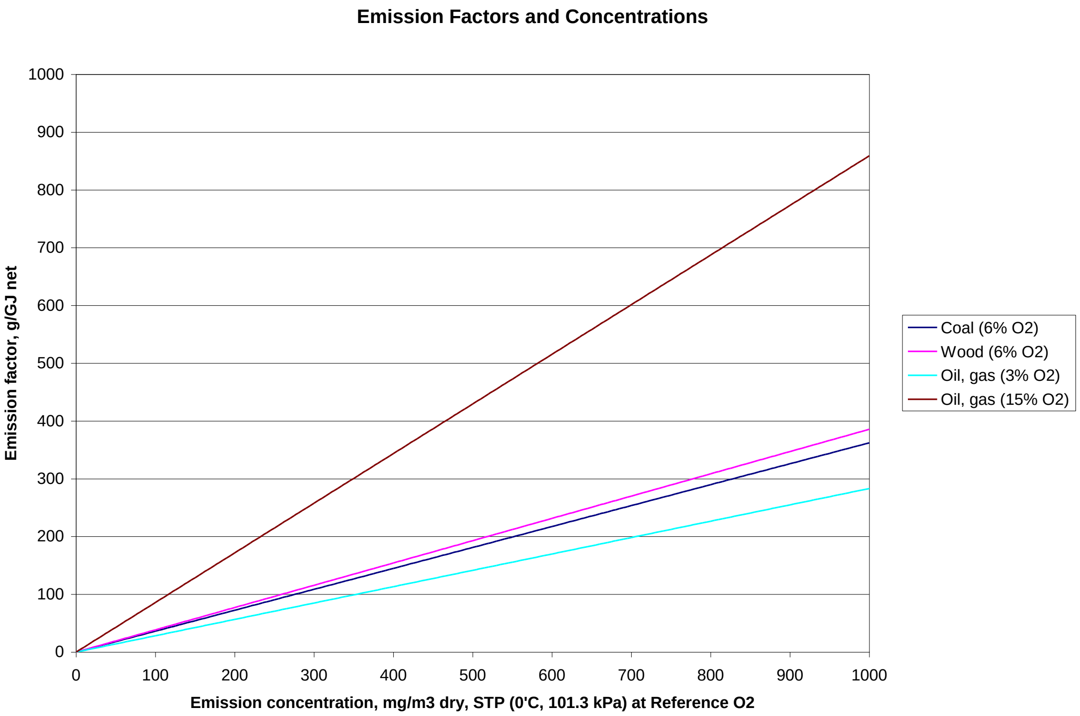
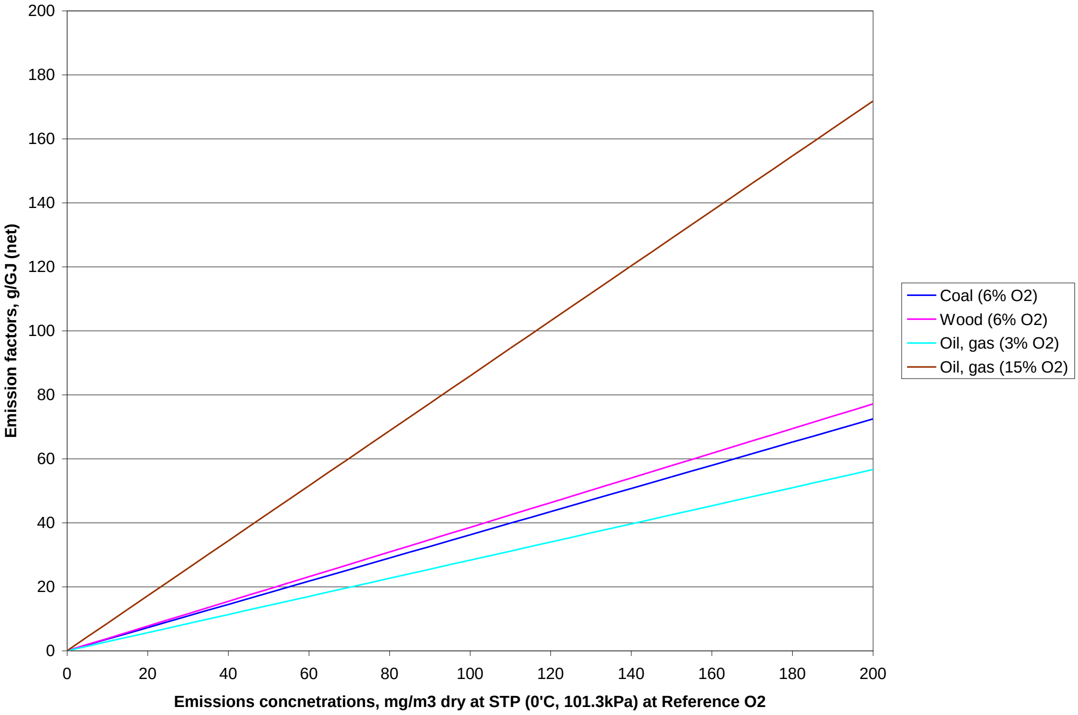


Figure E2 Emission factors — selected fuels and standardised concentrations up to 200 mg.m-3



Annex F Emission factors from older versions of the Guidebook

Chapter B111

Table Emission factors from older versions of the Guidebook

Table 24: NO_x emission factors [g/GJ] for combustion plants

					Thermal boiler capacity [MW]				
					>= 300[32]			>= 50 and < 300[32]	
			Type of fuel	NAPFUE code	Type of boiler[43]			Type of boiler	
					DBB/boiler[27]	WBB	FBC CFBC	DBB/boiler[27]	WBB
s	coal	hc	coking	101	see table 25	see table 25	70[1]	see table 25	see table 25
s	coal	hc	steam	102	see table 25	see table 25	70[1]	see table 25	see table 25
s	coal	hc	sub-bitumious	103	see table 25	see table 25	70[1]	see table 25	see table 25
s	coal	bc	brown coal/lignite	105	see table 25		70[1]	see table 25	
s	coal	bc	briquettes	106					
s	coke	hc	coke oven	107					
s	coke	bc	coke oven	108					
s	coke		petroleum	110				300[1]	
s	biomass		wood	111				200[1,15]	
s	biomass		charcoal	112					
s	biomass		peat	113	300[1,28]			300[1]	
s	waste		municipal	114					
s	waste		industrial	115					
s	waste		wood	116					
s	waste		agricultural	117					
l	oil		residual	203	210[1,29], 260[1,28], 155 - 296[19,20]			150[1,29], 170[1,29], 190[1,30], 210[1,30]	
l	oil		gas	204	64 - 68[21]			100[1]	
l	oil		diesel	205					
l	kerosene			206					
l	gasoline		motor	208					
l	naphtha			210					
l	black liquor			215					
g	gas		natural	301	170[1], 48 - 333[22] [23]			125[1,25], 150[1,26], 48 - 333[22,23,24]	
g	gas		liquified petroleum gas	303	88 - 333[23,24]			88 - 333[23,24]	
g	gas		coke oven	304	150[1], 88 - 333[23] [24]			110[1,25], 130[1,26], 88 - 333[23,24]	
g	gas		blast furnace	305	95[1], 88 - 333[23] [24]			65[1,25], 80[1,26], 88 - 333[23,24]	
g	gas		coke oven and blast furnace ga	306	88 - 333[23,24]			88 - 333[23,24]	
g	gas		waste	307	88 - 333[23,24]			88 - 333[23,24]	
g	gas		refinery	308	88 - 333[23,24]			140[1], 88 - 333[23,24]	
g	gas		biogas	309	88 - 333[23,24]			88 - 333[23,24]	
g	gas		from gas works	311					

Table 24: continued

Thermal boiler capacity [MW]													n
> 50 and < 300 [32]			< 50[32]										f
Type of boiler			Type of boiler						Gas turbine		Stationary engine		COR
FBC		GF	DBB/boiler[27]	WBB	FBC			GF					
PFBC	CFBC				PFBC	CFBC	AFBC		SC	CC	CI	SI	
150[1]	70[1]	150[1]	180[1,31], 230[1,29]			70[1]		150[1]					
150[1]	70[1]	150[1]	180[1,31], 230[1,29]			70[1]		150[1]					36
150[1]	70[1]	150[1]	180[1,31], 230[1,29]			70[1]		150[1]					20.5
150[1]	70[1]	150[1]	180[1,31], 230[1,29]			70[1]		150[1]					18
													33
			300[1]		300[1]	300[1]							
		200[1], 33 - 115[1	200[1], 33 - 115[15]					200[1,15]					50
160[1]	100[1]	230[1]	280[1]		160[1]	100[1]							15
		90 - 463[16,17]						90 - 463[16,17]					
		139 - 140[18]						139 - 140[18]					
													80
		88[6]											
			140[1,29], 180[1,30]						250[45]		1,090-1,200[45]		24
			80[1], 100[1]						120 [1,35], 350[1,33], 380[1,34], 780[1,		100 - 1,200[45]		50
									100 - 700[45], 300[46]		600[1,37,42], 1,200[1,38]	1,000[1,40,42], 1,800[1,39,42]	
													20
			100[1], 48 - 333[22,23,24]						150 - 360[45]		600[1,37,42], 1,200[1,38,4	1,000[1,40,42], 1,800[1,39,	22
									188[4,41]	187[4,41]			
			88 - 333[23,24]										35
			90[1,23,24]										70
			88 - 333[23,24]										6.
			88 - 333[23,24]										
			88 - 333[23,24]										35
			140[1,23,24]						150-151[45]				35
			88 - 333[23,24]										

Table 25: NO_x emission factors [g/GJ] for coal combustion according to the model (see Annexes 4 and 5)

Type of fuel			coal mining country	NAPFUE code	H_u [MJ/kg] (maf)	Thermal boiler capacity [MW] >= 50 [1]									
						Type of boiler									
						DBB					WBB				
						PM0[2]	PM1	PM2	PM3	PM4	PM0	PM1	PM2	PM3	PM4
						η= 0	η= 0.20	η=0.45	η=0.45	η=0.60	η= 0	η= 0.20	η=0.45	η=0.40	η=0.60
s	coal	hc	Australia	(101)	34	568	454	312	312	227	703	562	387	422	281
			Canada	(101)	33	500	405	278	278	202	627	501	345	376	251
			China	(101)	32	413	331	227	227	165	512	409	281	307	205
			Columbia	(101)	32	535	428	394	394	214	662	529	364	397	265
			Czech Republic	(101)	34	483	387	266	266	193	598	479	329	359	239
			France	101	35	374	299	205	205	149	463	370	254	278	185
			Germany RAG	102	35	384	307	211	211	154	476	381	262	285	190
			Germany others	101	30	495	396	272	272	198	613	490	337	368	245
			CIS	(101)	32	308	247	169	169	123	382	305	210	229	153
			Hungary	101	34	401	320	220	220	160	496	397	273	298	198
			India	103	30	551	441	303	303	220	682	545	375	409	273
			South Africa	(101)	32	569	456	313	313	228	705	504	388	423	282
			USA	(101)	34	563	450	310	310	225	697	558	383	418	279
			Venezuela	(101)	34	588	471	324	324	235	728	583	401	437	291
						η= 0	η= 0.20	η=0.45	η=0.40	η=0.60					
s	coal	bc	Czech Republic	105	28	506	405	278	304	202					
			Germany												
			- Rheinisch Coal	105	27	325	260	179	195	130					
			- Middle Germany	105	25	504	403	277	302	202					
			- East Germany	105	26	539	431	296	323	215					
			Hungary-1	105	36	379	303	208	227	151					
			Hungary-2	103	28	379	304	209	228	152					
			Poland	105	25	531	425	292	319	213					
			Portugal	105	25	461	369	254	277	185					
			Turkey-2	103	27	725	580	399	435	290					

[1] The emission factors [g/GJ] are given at full load operating modus.

[2] PM0 ... PM4 = most used combinations of primary measures; η = reduction efficiencies [ ]

PM0 - no primary measures
PM1 - one primary measure: LNB
PM2 - two primary measures: LNB/SAS
PM3 - two primary measures: LNB/OFA
PM4 - three primary measures: LNB/SAS/OFA

Table 26: NMVOC emission factors [g/GJ] for combustion plants

Type of fuel				NAPFUE code	Thermal boiler capacity [MW] >= 50 boiler	GF	< 50 boiler	Gas turbine	Stationary engine	no specification CORINAIR90[6]
s	coal	hc	coking	101	3[5], 30[2]	50[2]	600[1]			3[6]
s	coal	hc	steam	102	3[5], 30[2]	50[2]	600[1]			1 - 15[6]
s	coal	hc	sub-bituminous	103	3[5], 30[2]	50[2]	600[1]			1.5 - 15[6]
s	coal	bc	brown coal/lignite	105	30[2),3)]	50[2]				1.5 - 15[6]
s	coal	bc	briquettes	106			150[1]			
s	coke	hc	coke oven	107			12[1]			5 - 15[6]
s	coke	bc	coke oven	108						
s	coke		petroleum	110						1.5[6]
s	biomass		wood	111	80[2]		100[5], 150[1], 400[4]			10 - 48[6]
s	biomass		charcoal	112						
s	biomass		peat	113	30[2),3)]	30[2]				3 - 48[6]
s	waste		municipal	114						10[6]
s	waste		industrial	115						
s	waste		wood	116						40 - 48[6]
s	waste		agricultural	117						50[6]
l	oil		residual	203	10[2),3)]			3[7]	50[7]	1.5 - 47.6[6]
l	oil		gas	204	5[2]		15[1]	5[2], 1.5 - 2[7]	1.5 - 100[7], 100[2]	1.5 - 9.3[6]
l	oil		diesel	205						
l	kerosene			206						3[6]
l	gasoline		motor	208						
l	naphtha			210						3[6]
l	black liquor			215						3[6]
g	gas		natural	301	5[2]			5[2], 2.5 - 4[7]	200[2]	2 - 4[6]
g	gas		liquified petroleum gas	303						2 - 2.6[6]
g	gas		coke oven	304						2.5 - 167[6]
g	gas		blast furnace	305						1 - 2.5[6]
g	gas		coke oven and blast furnace gas	306						
g	gas		waste	307						2.5[6]
g	gas		refinery	308	25[2]			2.5[7]		2.1 - 10[6]
g	gas		biogas	309						2.5[6]
g	gas		from gas works	311						

[1] LIS 1977 /92/ [2] CORINAIR 1992 /80/ [3] DBB only [4] small consumers cf. /24/ [5] power plants cf. /24/

[6] CORINAIR90 data of combustion plants as point sources with a thermal capacity of > 300, 50 - 300, < 50 MW

[7] CORINAIR90 data, point sources

Table 28: CO emission factors [g/GJ] for combustion plants

Type of fuel				NAPFUE code	Type of combustion									
					Utility combustion			Commercial comb.		Industrial combustion				
					DBB/WBB/ boilers$^{1)}$	GF stoker		boiler	GF	DBB/WBB/ boiler$^{1)}$	GF stoker		GT	stat. E.
						spreader	travell.				spreader	travelling		
s	coal	hc	coking	101	$14^{3)}$	$121^{3)}$		$195^{3)}$		$9.7^{2)}$, $13^{4)}$	$81^{2)}$, $115^{4)}$	$97.2^{2)}$		
s	coal	hc	steam	102	$14^{3)}$	$121^{3)}$		$195^{3)}$		$9.7^{2)}$, $13^{4)}$	$115^{4)}$	$9.7^{2)}$		
s	coal	hc	sub-bituminous	103	$14^{3)}$	$121^{3)}$		$195^{3)}$		$9.7^{2)}$, $13^{4)}$	$81^{2)}$, $115^{4)}$	$97.2^{2)}$		
s	coal	bc	brown coal/lignite	105	$14^{3)}$	$121^{3)}$		$195^{3)}$		$16^{2)}$, $13^{4)}$	$133^{2)}$, $115^{4)}$	$160^{2)}$		
s	coal	bc	briquettes	106										
s	coke	hc	coke oven	107										
s	coke	bc	coke oven	108										
s	coke		petroleum	110										
s	biomass		wood	111	$1,473^{3)}$			$199^{3)}$		$1,504^{3)}$				
s	biomass		charcoal	112										
s	biomass		peat	113										
s	waste		municipal	114		$98^{3),6)}$		$19^{3)}$			$19^{3)7)}$, $96^{3)7)}$, 42 kg/Mg$^{3),8)}$			
s	waste		industrial	115										
s	waste		wood	116										
s	waste		agricultural	117				58 kg/Mg$^{3),8)}$						
l	oil		residual	203	$15^{3)}$			$17^{3)}$		$15^{3)}$			10 - $15^{10)}$	$100^{10)}$
l	oil		gas	204	$15^{3)}$			$16^{3)}$		$12^{3)}$			10 - $20^{10)}$ $20.6^{11)}$	12 - 1,130
l	oil		diesel	205										
l	kerosene			206										
l	gasoline		motor	208										
l	naphtha			210										
l	black liquor			215										
g	gas		natural	301	$19^{3)}$			$9.6^{3)}$		$17^{3)}$, $13^{5)}$				10 - $20^{10)}$, 3
g	gas		liquified petroleum gas	303										
g	gas		coke oven	304										
g	gas		blast furnace	305										
g	gas		coke oven and blast furnace gas	306										
g	gas		waste	307										
g	gas		refinery	308										$10^{10)}$
g	gas		biogas	309										
g	gas		from gas works	311										

1) DBB/WBB for coal combustion; boiler for other fuel combustion

2) EPA 1987 /85/, CORINAIR 1992 /80/

3) Radian 1990 /102/, IPCC 1994 /88/, without primary measure

4) OECD 1989 /100/, CORINAIR 1992 /80/

5) CORINAIR 1992 /80/, part 8

6) grate firing without specification

7) small combustion 19 g/GJ, mass burning 96 g/GJ

8) open burning

9) CORINAIR90 data of combustion plants as point sources with a thermal capacity of > 300, 50 - 300, < 50 MW

10) CORINAIR90 data, point sources

11) AP42 /115/

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Table F.2a Emission factors for combustion processes burning hard coal

Fuel	NAPFUE	NFR Codes	Activity description	Activity detail	Emission factor			Notes
Hard coal					**TSP**	**PM_{10}**	**$PM_{2.5}$**	
Bituminous coal	101	Various	Electricity, CHP, heat	FF < 20 $mg \cdot Nm^{-3}$	6	6	5	CEPMEIP 'BAT'
				ESP (or FF) < 50 $mg \cdot Nm^{-3}$	15	12	6	Scaled from CEPMEIP ESP factor. TSP scaled to a nominal 100 $mg \cdot Nm^{-3}$ limit
				ESP < 100 $mg \cdot Nm^{-3}$	30	25	12	From CEPMEIP sub-bit coal 'high efficiency ESP', TSP scaled to a nominal 100 $mg \cdot Nm^{-3}$ limit
				ESP Old/conventional < 500 $mg \cdot Nm^{-3}$	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 $mg \cdot Nm^{-3}$	6	6	5	CEPMEIP 'BAT'
				ESP (or FF) < 50 $mg \cdot Nm^{-3}$	15	12	6	Scaled from CEPMEIP ESP factor (TSP scaled to a nominal 100 $mg \cdot Nm^{-3}$ limit)
				ESP < 100 $mg \cdot Nm^{-3}$	30	25	12	From CEPMEIP sub-bit coal 'high efficiency ESP', TSP scaled to a nominal 100 $mg \cdot Nm^{-3}$ limit
				ESP Old/conventional < 500 $mg \cdot Nm^{-3}$	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 F.2b Emission factors for combustion processes burning brown coal

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
					TSP	PM_{10}	$PM_{2.5}$	
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 F.2c Emission factors for combustion processes burning other solid fuels

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
					TSP	PM_{10}	$PM_{2.5}$	
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 F.2d Emission factors for combustion processes burning natural gas

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
					TSP	**PM_{10}**	**$PM_{2.5}$**	
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 F.2e Emission factors for combustion of derived gases

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
					TSP	PM_{10}	$PM_{2.5}$	
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 F.2f Emission factors for combustion of heavy fuel oil

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
					TSP	PM_{10}	$PM_{2.5}$	
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 F.2g Emission factors for combustion of other liquid fuels

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
					TSP	PM_{10}	$PM_{2.5}$	
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 F.2h Emission factors for combustion of biomass

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
					TSP	PM_{10}	$PM_{2.5}$	
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)

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Table F3 ***Default emission factors for use with simpler methodology (Tier 1)***

Fuel	Technology	Emission factor, g GJ^{-1}			Notes (4)
		TSP	PM_{10}	$PM_{2.5}$	
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	

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(4) Source: R. Stewart (2006); US EPA AP 42 (1996); CEPMEIP (2006).

Table F3a **Emission factors for combustion processes burning hard coal**

Fuel	NAPFUE	NFR Codes	Activity description	Activity detail (5)	Emission factor g·GJ^{-1}			Notes (6)
Hard coal					**TSP**	**PM$_{10}$**	**PM$_{2.5}$**	
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 MW$_{th}$ 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 MW$_{th}$ 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)

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(5) KEY: FGD: flue gas desulphurisation; ESP: electrostatic precipitator; FF: fabric filter; BAT: Best Available Techniques; LCPD: large combustion plant data.

(6) Sources: R. Stewart (2006); US EPA AP-42 (1996); CEPMEIP (2006).

Fuel	NAPFUE	NFR Codes	Activity description	Activity detail (5)	Emission factor g·GJ^{-1}			Notes (6)
Coke	107							Coke is unlikely to be burned as primary fuel, when co-fired use the factor for the principal fuel.

Table F3b Emission factors for combustion processes burning brown coal

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference/Comments
					TSP	**PM_{10}**	**$PM_{2.5}$**	
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 MW_{th}, < 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 F3c Emission factors for combustion processes burning other solid fuels

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference
					TSP	PM_{10}	$PM_{2.5}$	
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 F3d Emission factors for combustion processes burning natural gas

Fuel (IPCC Cat)	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference
					TSP	PM_{10}	$PM_{2.5}$	
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 PM_1)

Table F3e Emission factors for combustion of derived gases

Fuel (IPCC Cat)	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference
					TSP	PM_{10}	$PM_{2.5}$	
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 F3f Emission factors for combustion of heavy fuel oil

Fuel (IPCC Cat)	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference
					TSP	PM_{10}	$PM_{2.5}$	
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 F3g Emission factors for combustion of other liquid fuels

Fuel (IPCC Cat)	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference
					TSP	PM_{10}	$PM_{2.5}$	
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 F3h Emission factors for combustion of biomass

Fuel (IPCC Cat)	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference
					TSP	PM_{10}	$PM_{2.5}$	
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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Table F4 ***Default emission factors for use with simpler methodology (Tier 1)***

Fuel	Technology	Emission factor, g·GJ^{-1}			Notes
		TSP	PM_{10}	$PM_{2.5}$	
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 F4a **Emission factors for gas turbines combustion processes**

Fuel	NAPFUE	NFR Codes	Activity description	Activity detail	Emission factor, g·GJ^{-1}			Notes
					TSP	PM_{10}	$PM_{2.5}$	
Natural gas					0.9	0.9	0.9	Sierra (234 tests), assumed all $PM_{2.5}$
Gas oil					3	3	3	Sierra (15 tests), assumed all $PM_{2.5}$

Table F4b 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	PM$_{10}$	PM$_{2.5}$	
Natural gas			Dual fuel engine, gas with HFO		11	11	11	LCP BREF, assumed all PM$_{2.5}$
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