Category		Title
NFR:	**1.A.1**	**Energy industries**
SNAP:	**01**	**Combustion in energy and transformation industries**
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Coordinator
Carlo Trozzi

Contributing authors (including to earlier versions of this chapter)
Otto Rentz, Dagmar Oertel, Mike Woodfield and Robert Stewart

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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 (TSP))	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
Boilers and furnaces	X	X	X	X	X	X	X	X	X	X	X	X		
Gas turbine	X	X	X	X	X	X		X						
CI engine	X	X	X	X	X	X	X	X	X		X			
Refinery activities	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

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 Large Combustion Plant Directive (LCPD) (2001/80/EC) and the Directive on Integrated Pollution Prevention and Control (IPPCD) (96/61/EC) [EC-LCPD, 2001; EC-IPPCD, 1996].

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.

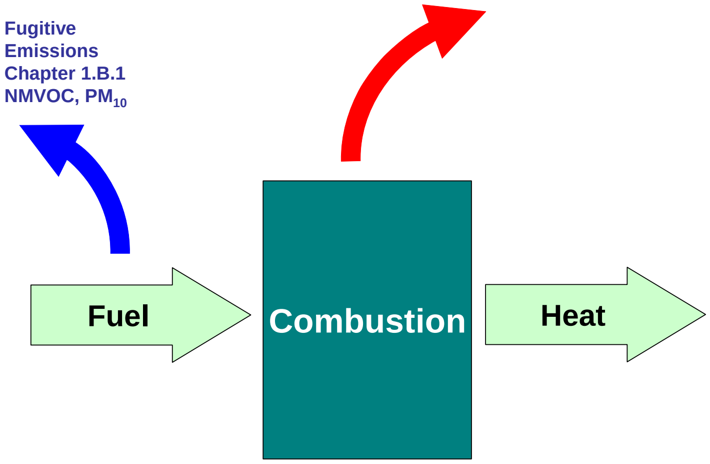

Figure 2-1 Process scheme for heat plant, adapted from IPCC Figure 2.2 in the energy industries chapter

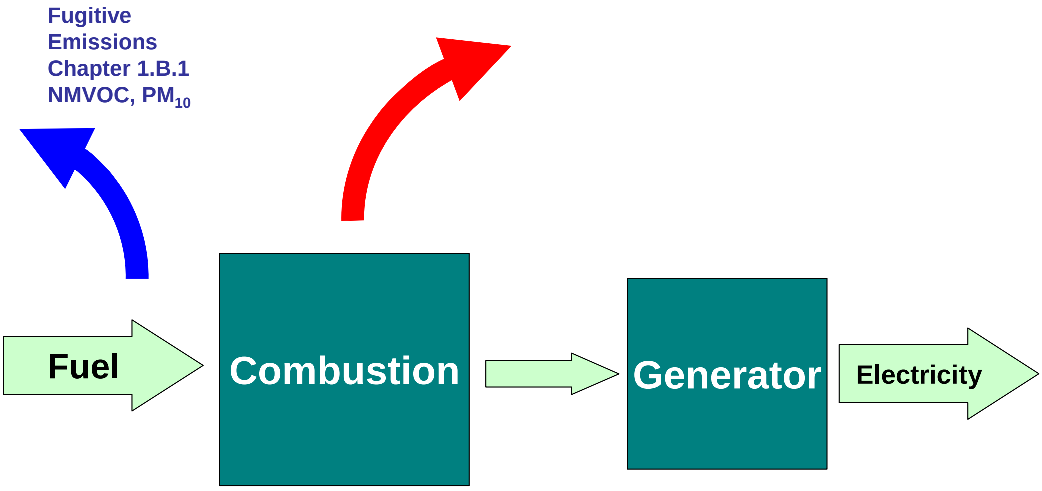

Figure 2-2 Process scheme for power plant, adapted from IPCC Figure 2.2 in the energy industries chapter

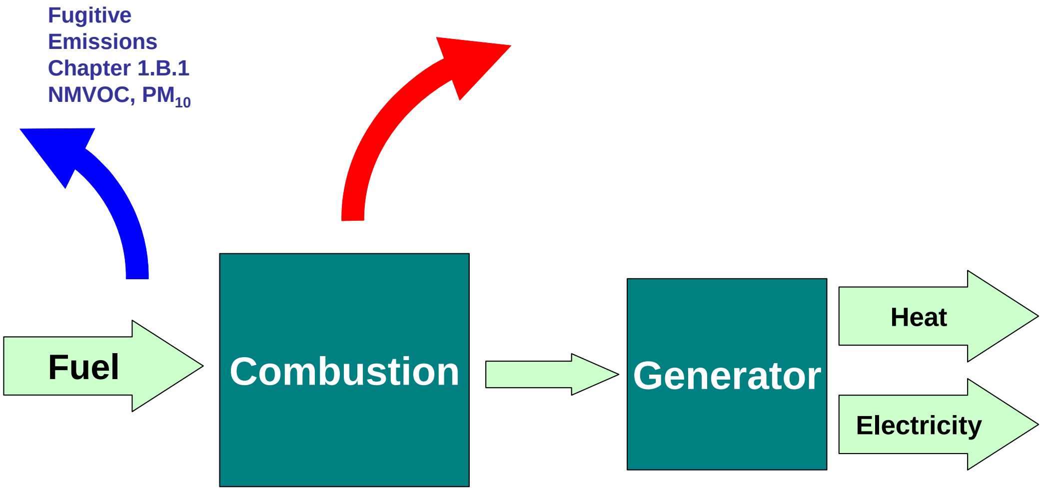

Figure 2-3 Process scheme for combined power and heat plant, adapted from IPCC Figure 2.2 in the energy industries chapter

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.

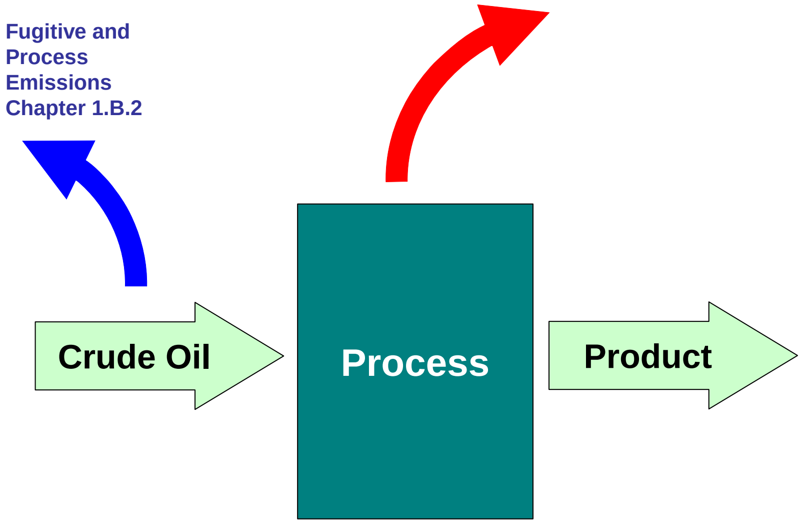

Figure 2-4 Process scheme for petroleum refinery, adapted from IPCC Figure 2.3 in the energy industries chapter

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.

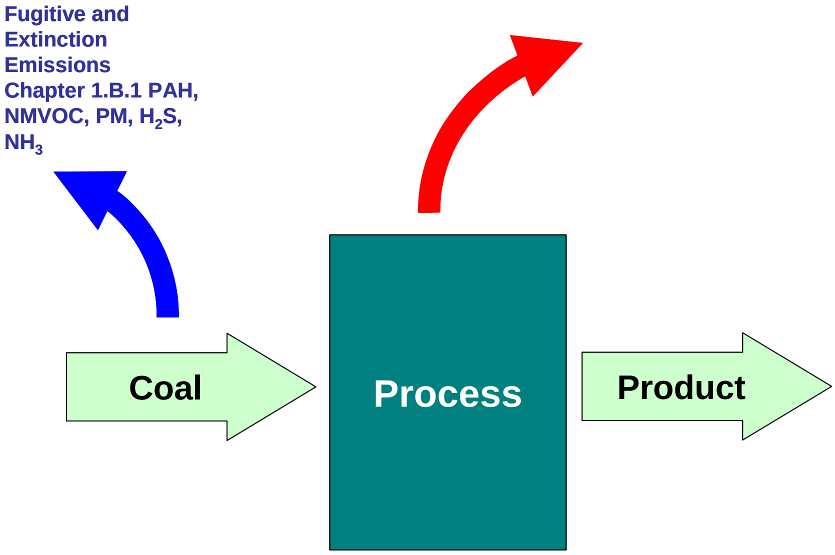

Figure 2-5 Process scheme for coke ovens, adapted from IPCC Figure 2.3 in the energy industries chapter

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 energy installations [European Integrated Pollution Prevention and Control Bureau (EIPPCB), 2006] 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 1 200 °C leading to dry ash discharge from the combustion chamber due to combustion temperatures from. This type of boiler is mainly used for the combustion of hard coal and brown coal/lignite and is applied all over Europe.

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

In fluidised bed combustion (FBC), the combustion of fuel takes place by injection of combustion air through the bottom of the boiler into a turbulent bed. The typical relatively low emissions are achieved by air staging, limestone addition and low combustion temperatures of about 750–950 °C. FBC is in particular adapted to coals rich in ash. Only few large combustion plants are equipped with the FBC technique; in the category of thermal capacities $\geq$ 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

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.

Gas turbines

Gas turbines are installed with a thermal capacity ranging from several hundred kW up to about 1 000 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.

Stationary engines

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

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) emission database (WebDab) (^{1}) are given in Table 3-1:

Table 3-1 Contributions (%) of emissions from public electricity and heat production activities to total emissions of the WebDab2005

NFR Code	Data	SOx	NOx	NMVOC	CO	NH_3	PM10	PM2.5	TSP
1.A.1.a — Public electricity and heat production	No of countries reporting	34	35	34	33	33	33	34	33
	Lowest value	1.4	0.6	0.1	0.2	0.0	0.0	0.2	0.0
	Typical contribution	45.0	22.5	2.6	1.6	0.4	11.0	12.3	11.3
	Highest value	95.2	95.0	19.2	5.9	11.1	56.9	64.5	48.4

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

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.

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).

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. VOC emissions tend to decrease as the plant size increases (Rentz et al, 1993).

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

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(^{1}) Available here: http://webdab.emep.int/

CO and VOC are similarly influenced by combustion conditions. Substantial emissions of CO can occur if combustion conditions are poor.

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).

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.

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 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 (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).

Methane (CH_4)

Refer to IPCC guidance.

Carbon dioxide (CO_2)

Refer to IPCC guidance.

Nitrous oxide (N_2O)

Refer to IPCC guidance.

3.3 Controls

Details of relevant abatement technologies for combustion plant are described in the BREF note for large combustion plant (http://eippcb.jrc.es/pages/FActivities.htm); 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.

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 %.

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 %.

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

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.

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.

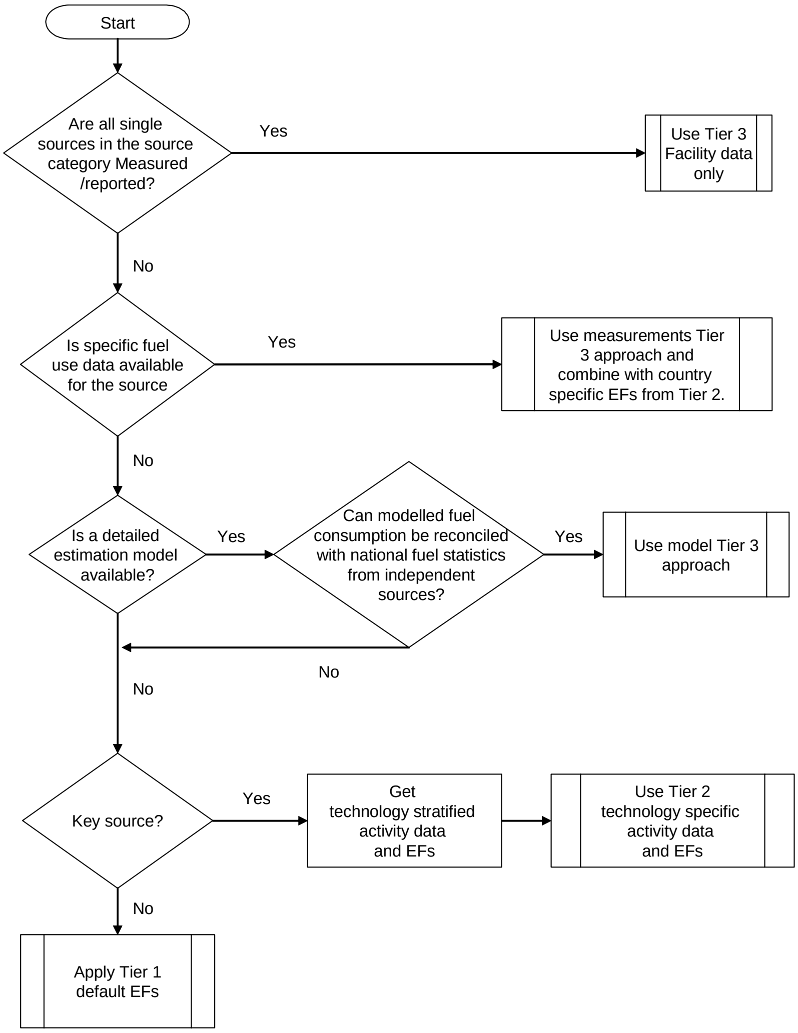

Figure 3-1 **Decision tree for combustion in energy transformation industries**

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:

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

$E_{pollutant}$	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 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 3-2) and are given in Table 3-3 to Table 3-9.

Table 3-2 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
Derived gases	Gas works gas, coke oven gas, blast furnace gas
Heavy fuel oil	Residual fuel oil, refinery feedstock, petroleum coke
Other liquid fuels	Gas oil, kerosene, naphtha, natural gas liquids, liquefied petroleum gas, orimulsion, bitumen, shale oil, refinery gas
Biomass	Wood, charcoal, vegetable (agricultural) waste

The emission factors provided in Table 3-3 to Table 3-9 have been derived from available materials, taking into account the results of an assessment of emission factors included in previous versions of the Guidebook and elsewhere, including the newer information from the BREF document on Best Available Techniques in Large Combustion Plants (European Commission, 2006). The emission factors are grouped by major fuel types. In the absence of detail on types and relative use of types of combustion or abatement technology, which will be different for each country, the proposed factors represent a mean for the range of technologies in use with the 95 % figures a measure of the range of emissions in the sector. The factors will represent a very wide range of combustion technologies and emissions; they do not represent BAT or unabated emissions.

Note that 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.

Table 3-3 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 estimated	NH_3, Benzo(b)fluoranthene, Benzo(k)fluoranthene				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	310	g/GJ	70	700	US EPA 1998, chapter 1.1; average of bituminous coal combustion techniques
CO	150	g/GJ	5.8	1000	US EPA 1998, chapter 1.1; average of bituminous coal combustion techniques
NMVOC	1.2	g/GJ	0.6	2.4	US EPA 1998, chapter 1.1
SO_x	820	g/GJ	300	5000	See note
TSP	30	g/GJ	3.0	300	US EPA 1998, chapter 1.1
PM_{10}	20	g/GJ	2.0	200	US EPA 1998, chapter 1.1
$PM_{2.5}$	9	g/GJ	0.9	90	US EPA 1998, chapter 1.1
Pb	8.1	mg/GJ	4.9	11.4	US EPA 1998, chapter 1.1
Cd	1.0	mg/GJ	0.6	1.4	US EPA 1998, chapter 1.1
Hg	1.6	mg/GJ	1.0	2.3	US EPA 1998, chapter 1.1
As	8.0	mg/GJ	4.8	11	US EPA 1998, chapter 1.1
Cr	5.0	mg/GJ	3.0	7.1	US EPA 1998, chapter 1.1
Cu	4.8	mg/GJ	0.2	16	Expert judgement, derived from Guidebook (2006)
Ni	5.4	mg/GJ	3.3	7.6	US EPA 1998, chapter 1.1
Se	25	mg/GJ	15	35	US EPA 1998, chapter 1.1
Zn	19	mg/GJ	0.39	155	Expert judgement, derived from Guidebook (2006)
PCB	170	µg/GJ	85	260	Kakareka et. al (2004)
PCDD/F	10	ng I-TEQ/GJ	5	15	UNEP (2005); Coal fired power boilers
Benzo(a)pyrene	0.7	µg/GJ	0.3	2.2	US EPA 1998, chapter 1.1
Indeno(1,2,3-cd)pyrene	1.2	µg/GJ	0.6	2.4	US EPA 1998, chapter 1.1
HCB	0.62	µg/GJ	0.3	0.9	Guidebook (2006)

Notes:

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.

TSP is based on AP-42 and assumes 20 % ash content and PM emissions from solid mineral fuels generally similar to coal.

Table 3-4 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 estimated	NH_3, PCB, Benzo(b)fluoranthene, Benzo(k)fluoranthene, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	360	g/GJ	70	700	US EPA 1998, chapter 1.7; average of lignite combustion techniques
CO	113	g/GJ	6.1	1100	US EPA 1998, chapter 1.7
NMVOC	1.7	g/GJ	0.8	3.4	US EPA 1998, chapter 1.7
SO_x	820	g/GJ	330	5000	See Note
TSP	30	g/GJ	3	300	US EPA 1998, chapter 1.7
PM_{10}	20	g/GJ	2	200	US EPA 1998, chapter 1.7
$PM_{2.5}$	9	g/GJ	0.9	90	US EPA 1998, chapter 1.7
Pb	18	mg/GJ	11	25	US EPA 1998, chapter 1.7
Cd	2.1	mg/GJ	1.3	3.0	US EPA 1998, chapter 1.7
Hg	3.5	mg/GJ	2.1	4.9	US EPA 1998, chapter 1.7
As	17	mg/GJ	10	24	US EPA 1998, chapter 1.7
Cr	11	mg/GJ	6.6	15	US EPA 1998, chapter 1.7
Cu	0.3	mg/GJ	0.1	0.8	Expert judgement, derived from Guidebook (2006)
Ni	12	mg/GJ	7.1	16	US EPA 1998, chapter 1.7
Se	55	mg/GJ	33	76	US EPA 1998, chapter 1.7
Zn	4.5	mg/GJ	0.5	17	Expert judgement, derived from Guidebook (2006)
PCDD/F	10	ng I-TEQ/GJ	5	15	UNEP (2005); Coal fired power boilers
Benzo(a)pyrene	1.6	µg/GJ	0.5	4.8	US EPA 1998, chapter 1.7
Indeno(1,2,3-cd)pyrene	2.6	µg/GJ	1.3	5.1	US EPA 1998, chapter 1.7

Notes:

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.

TSP is based on AP-42 and assumes 20 % ash content and PM emissions from solid mineral fuels generally similar to coal.

Table 3-5 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 estimated	NH_3, PCB, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	89	g/GJ	16	180	US EPA 1998, chapter 1.4
CO	39	g/GJ	20	60	US EPA 1998, chapter 1.4
NMVOC	1.5	g/GJ	0.8	6.0	US EPA 1998, chapter 1.4
SO_x	0.3	g/GJ	0.2	0.4	US EPA 1998, chapter 1.4
TSP	0.9	g/GJ	0.4	1.3	US EPA 1998, chapter 1.4
PM_{10}	0.9	g/GJ	0.4	1.3	US EPA 1998, chapter 1.4
$PM_{2.5}$	0.9	g/GJ	0.4	1.3	US EPA 1998, chapter 1.4
Pb	0.2	mg/GJ	0.1	0.7	US EPA 1998, chapter 1.4
Cd	0.5	mg/GJ	0.2	1.5	US EPA 1998, chapter 1.4
Hg	0.10	mg/GJ	0.05	0.15	van der Most & Veldt 1992
As	0.09	mg/GJ	0.03	0.3	US EPA 1998, chapter 1.4
Cr	0.7	mg/GJ	0.2	2.0	US EPA 1998, chapter 1.4
Cu	0.4	mg/GJ	0.2	0.8	US EPA 1998, chapter 1.4
Ni	1.0	mg/GJ	0.5	2.0	US EPA 1998, chapter 1.4
Se	0.01	mg/GJ	0.004	0.03	US EPA 1998, chapter 1.4
Zn	14	mg/GJ	4.5	40	US EPA 1998, chapter 1.4
PCDD/F	0.5	ng I-TEQ/GJ	0.25	0.75	UNEP (2005); Light fuel oil/natural gas fired power boilers
Benzo(a)pyrene	0.6	µg/GJ	0.2	1.7	US EPA 1998, chapter 1.4
Benzo(b)fluoranthene	0.8	µg/GJ	0.3	2.5	US EPA 1998, chapter 1.4
Benzo(k)fluoranthene	0.8	µg/GJ	0.3	2.5	US EPA 1998, chapter 1.4
Indeno(1,2,3-cd)pyrene	0.8	µg/GJ	0.3	2.5	US EPA 1998, chapter 1.4

Notes:

Factor for SO_x is based on approximately 0.01 gm3 mass sulphur content. Emission factor for PCDD/F is stated to be applicable light fuel oil and natural gas use in power station boilers but is based mainly on data from oil combustion. UNEP also reports limited data for gas combustion of between 0.02 and 0.03 ng TEQ/GJ for natural gas-fired boilers.

Table 3-6 Tier 1 emission factors for source category 1.A.1.a using derived gases

Tier 1 default emission factors					
	Code	Name			
NFR Source Category	1.A.1.a	Public electricity and heat production			
Fuel	Derived Gases				
Not estimated	PCB, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	140	g/GJ	90	350	Expert judgement derived from Guidebook (2006)
CO	10	g/GJ	0.1	65	CORINAIR90
NMVOC	2.5	g/GJ	1	10	CORINAIR90
SO_x	0.3	g/GJ	0.2	0.4	US EPA 1998, chapter 1.4
NH3	0.9	g/GJ	0.4	1.3	CORINAIR90
TSP	5	g/GJ	2.5	7.5	Expert judgement based on Visschedijk et al (2004)
PM_{10}	5	g/GJ	2.5	7.5	Expert judgement based on Visschedijk et al (2004)
$PM_{2.5}$	5	g/GJ	2.5	7.5	Expert judgement based on Visschedijk et al (2004)
Pb	0.2	mg/GJ	0.1	0.7	US EPA 1998, chapter 1.4
Cd	0.5	mg/GJ	0.2	1.5	US EPA 1998, chapter 1.4
Hg	0.1	mg/GJ	0.04	0.4	US EPA 1998, chapter 1.4
As	0.09	mg/GJ	0.03	0.3	US EPA 1998, chapter 1.4
Cr	0.7	mg/GJ	0.2	2.0	US EPA 1998, chapter 1.4
Cu	0.4	mg/GJ	0.2	0.8	US EPA 1998, chapter 1.4
Ni	1.0	mg/GJ	0.5	2.0	US EPA 1998, chapter 1.4
Se	0.01	mg/GJ	0.004	0.03	US EPA 1998, chapter 1.4
Zn	14	mg/GJ	4.5	40	US EPA 1998, chapter 1.4
PCDD/F	0.5	ng I-TEQ/GJ	0.25	0.75	UNEP (2005); Light fuel oil/natural gas fired power boilers
Benzo(a)pyrene	0.6	µg/GJ	0.2	1.7	US EPA 1998, chapter 1.4
Benzo(b)fluoranthene	0.8	µg/GJ	0.3	2.5	US EPA 1998, chapter 1.4
Benzo(k)fluoranthene	0.8	µg/GJ	0.3	2.5	US EPA 1998, chapter 1.4
Indeno(1,2,3-cd)pyrene	0.8	µg/GJ	0.3	2.5	US EPA 1998, chapter 1.4

Notes:

Factor for SO_x is based on approximately 0.01 gm3 mass sulphur content. Factors for heavy metals based on USEPA data for natural gas.

Emission factor for PCDD/F is stated to be applicable light fuel oil and natural gas use in power station boilers but is based mainly on data from oil combustion. UNEP also reports limited data for gas combustion of between 0.02 and 0.03 ng TEQ/GJ for natural gas-fired boilers.

Table 3-7 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 estimated	NH_3, PCB, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	215	g/GJ	150	300	Expert judgement derived from Guidebook (2006)
CO	5	g/GJ	3	7	US EPA 1998, chapter 1.3
NMVOC	0.8	g/GJ	0.48	1.28	US EPA 1998, chapter 1.3
SO_x	485	g/GJ	150	1700	See Note
TSP	25	g/GJ	8	75	Expert judgement based on Visschedijk et al (2004)
PM_{10}	18	g/GJ	6	55	Expert judgement based on Visschedijk et al (2004)
$PM_{2.5}$	13	g/GJ	4	40	Expert judgement based on Visschedijk et al (2004)
Pb	4.9	mg/GJ	2.4	10	US EPA 1998, chapter 1.3
Cd	1.3	mg/GJ	0.6	3.0	US EPA 1998, chapter 1.3
Hg	0.4	mg/GJ	0.2	1.0	US EPA 1998, chapter 1.3
As	4.3	mg/GJ	2.1	8.5	US EPA 1998, chapter 1.3
Cr	2.7	mg/GJ	1.4	5.5	US EPA 1998, chapter 1.3
Cu	5.7	mg/GJ	2.8	11	US EPA 1998, chapter 1.3
Ni	273	mg/GJ	140	550	US EPA 1998, chapter 1.3
Se	2.2	mg/GJ	1.1	4.4	US EPA 1998, chapter 1.3
Zn	94	mg/GJ	47	190	US EPA 1998, chapter 1.3
PCDD/F	2.5	ng I-TEQ/GJ	1.3	3.8	UNEP (2005); Heavy fuel fired power boilers
Indeno(1,2,3-cd)pyrene	6.9	µg/GJ	3.5	14	US EPA 1998, chapter 1.3

Note:

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.

Table 3-8 Tier 1 emission factors for source category 1.A.1.a using other liquid fuels

Tier 1 default emission factors					
	Code	Name			
NFR Source Category	1.A.1.a	Public electricity and heat production			
Fuel	Other Liquid Fuels				
Not estimated	NH_3, PCB, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	180	g/GJ	20	440	CORINAIR90
CO	15	g/GJ	10	310	CORINAIR90
NMVOC	0.8	g/GJ	0.48	1.28	US EPA 1998, chapter 1.3
SO_x	460	g/GJ	40	1600	See Note
TSP	3	g/GJ	1	9	Expert judgement based on Visschedijk et al (2004)
PM_{10}	2	g/GJ	0.7	6	Expert judgement based on Visschedijk et al (2004)
$PM_{2.5}$	1	g/GJ	0.3	3	Expert judgement based on Visschedijk et al (2004)
Pb	4.1	mg/GJ	0.4	40	US EPA 1998, chapter 1.3
Cd	1.4	mg/GJ	0.1	15	US EPA 1998, chapter 1.3
Hg	1.4	mg/GJ	0.1	15	US EPA 1998, chapter 1.3
As	1.8	mg/GJ	0.2	20	US EPA 1998, chapter 1.3
Cr	1.4	mg/GJ	0.1	15	US EPA 1998, chapter 1.3
Cu	2.7	mg/GJ	0.3	30	US EPA 1998, chapter 1.3
Ni	1.4	mg/GJ	0.1	15	US EPA 1998, chapter 1.3
Se	6.8	mg/GJ	0.7	70	US EPA 1998, chapter 1.3
Zn	1.8	mg/GJ	0.2	20	US EPA 1998, chapter 1.3
PCDD/F	1.5	ng I-TEQ/GJ	0.8	2.3	UNEP (2005); Shale oil fired power plants
Indeno(1,2,3-cd)pyrene	6.9	µg/GJ	3.5	14	US EPA 1998, chapter 1.3

Note:

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.

Table 3-9 Tier 1 emission factors for source category 1.A.1.a using biomass

Tier 1 default emission factors					
	Code	Name			
NFR Source Category	1.A.1.a	Public electricity and heat production			
Fuel	Biomass				
Not estimated	NH_3				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	211	g/GJ	60	420	US EPA 2003, chapter 1.6
CO	258	g/GJ	155	360	US EPA 2003, chapter 1.6
NMVOC	7.3	g/GJ	2.4	22	US EPA 2003, chapter 1.6
SO_x	11	g/GJ	6.5	15	US EPA 2003, chapter 1.6
TSP	51	g/GJ	12	697	US EPA 2003, chapter 1.6
PM_{10}	38	g/GJ	5.7	645	US EPA 2003, chapter 1.6
$PM_{2.5}$	33	g/GJ	5.2	555	US EPA 2003, chapter 1.6
Pb	21	mg/GJ	12	29	US EPA 2003, chapter 1.6
Cd	1.8	mg/GJ	1.1	2.5	US EPA 2003, chapter 1.6
Hg	1.5	mg/GJ	0.9	2.1	US EPA 2003, chapter 1.6
As	9.5	mg/GJ	5.7	13.2	US EPA 2003, chapter 1.6
Cr	9.0	mg/GJ	5.4	12.6	US EPA 2003, chapter 1.6
Cu	21	mg/GJ	13	29	US EPA 2003, chapter 1.6
Ni	14	mg/GJ	8.5	20	US EPA 2003, chapter 1.6
Se	1.2	mg/GJ	0.7	1.7	US EPA 2003, chapter 1.6
Zn	181	mg/GJ	108	253	US EPA 2003, chapter 1.6
PCB	60	µg/GJ	30	90	Kakareka et. al (2004)
PCDD/F	50	ng I-TEQ/GJ	25	75	UNEP (2005) (for clean wood)
Benzo(a)pyrene	1.12	mg/GJ	0.67	1.57	US EPA 2003, chapter 1.6
Benzo(b)fluoranthene	0.04	mg/GJ	0.02	0.06	US EPA 2003, chapter 1.6
Benzo(k)fluoranthene	0.02	mg/GJ	0.01	0.02	US EPA 2003, chapter 1.6
Indeno(1,2,3-cd)pyrene	0.37	mg/GJ	0.19	0.56	US EPA 2003, chapter 1.6
HCB	6.0	µg/GJ	3.0	9.0	Guidebook (2006)

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

- 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:

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

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.

This section provides a series of technology-specific pollutant emission factors for combustion.

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, wood
Wet bottom boiler	Coking coal, steam coal, sub-bituminous coal, brown coal, lignite,
Fluid bed boiler	Hard coal, brown coal, wood, peat
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.

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)					
Technologies/Practices	Dry Bottom Boilers				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, Benzo(b)fluoranthene, Benzo(k)fluoranthene				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	324	g/GJ	200	350	US EPA 1998, chapter 1.1
CO	10	g/GJ	6	15	US EPA 1998, chapter 1.1
NMVOC	1.2	g/GJ	0.6	2.4	US EPA 1998, chapter 1.1
SO_x	820	g/GJ	330	5000	See note
TSP	30	g/GJ	3	300	US EPA 1998, chapter 1.1
PM_{10}	20	g/GJ	2	200	US EPA 1998, chapter 1.1
$PM_{2.5}$	9	g/GJ	0.9	90	US EPA 1998, chapter 1.1
Pb	8.6	mg/GJ	5.2	12	US EPA 1998, chapter 1.1
Cd	1.0	mg/GJ	0.6	1.5	US EPA 1998, chapter 1.1
Hg	1.7	mg/GJ	1.0	2.4	US EPA 1998, chapter 1.1
As	8.4	mg/GJ	5.0	12	US EPA 1998, chapter 1.1
Cr	5.3	mg/GJ	3.2	7.5	US EPA 1998, chapter 1.1
Cu	7.8	mg/GJ	0.2	16	Expert judgement, derived from Guidebook (2006)
Ni	5.7	mg/GJ	3.4	8.0	US EPA 1998, chapter 1.1
Se	27	mg/GJ	16	37	US EPA 1998, chapter 1.1
Zn	19	mg/GJ	7.8	155	Expert judgement, derived from Guidebook (2006)
PCB	170	µg/GJ	85	260	Kakareka et. al (2004)
PCDD/F	10	ng I-TEQ/GJ	5	15	UNEP (2005); Coal fired power boilers
Benzo(a)pyrene	0.7	µg/GJ	0.2	2.2	US EPA 1998, chapter 1.1
Indeno(1,2,3-cd)pyrene	1.2	µg/GJ	0.6	2.4	US EPA 1998, chapter 1.1
HCB	0.62	µg/GJ	0.3	0.9	Guidebook (2006)

Notes:

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.

TSP is based on AP-42 and assumes 20 % ash content and PM emissions from solid mineral fuels generally similar to coal.

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)					
Technologies/Practices	Wet and Dry Bottom Boilers				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, Cu, PCB, Benzo(b)fluoranthene, Benzo(k)fluoranthene, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	286	g/GJ	143	571	US EPA 1998, chapter 1.7
CO	20	g/GJ	6.7	61	US EPA 1998, chapter 1.7
NMVOC	1.7	g/GJ	0.8	3.4	US EPA 1998, chapter 1.7
SO_x	820	g/GJ	330	5000	See Note
TSP	40	g/GJ	20	80	Expert judgement based on Visschedijk et al (2004)
PM_{10}	30	g/GJ	15	60	Expert judgement based on Visschedijk et al (2004)
$PM_{2.5}$	14	g/GJ	7	28	Expert judgement based on Visschedijk et al (2004)
Pb	17.6	mg/GJ	10.6	24.7	US EPA 1998, chapter 1.7
Cd	2.1	mg/GJ	1.3	3.0	US EPA 1998, chapter 1.7
Hg	3.5	mg/GJ	2.1	4.9	US EPA 1998, chapter 1.7
As	17.2	mg/GJ	10.3	24.1	US EPA 1998, chapter 1.7
Cr	10.9	mg/GJ	6.6	15.3	US EPA 1998, chapter 1.7
Ni	11.8	mg/GJ	7.1	16.5	US EPA 1998, chapter 1.7
Se	54.6	mg/GJ	32.8	76.5	US EPA 1998, chapter 1.7
Zn	4.6	mg/GJ	0.5	16.8	Guidebook (2006)
PCDD/F	10	ng I-TEQ/GJ	5	15	UNEP (2005); Coal fired power boilers
Benzo(a)pyrene	1.6	µg/GJ	0.8	3.2	US EPA 1998, chapter 1.7
Indeno(1,2,3-cd)pyrene	2.6	µg/GJ	1.3	5.1	US EPA 1998, chapter 1.7

Notes:

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.

TSP is based on AP-42 and assumes 20 % ash content and PM emissions from solid mineral fuels generally similar to coal.

Table 3-13 Tier 2 emission factors for source category 1.A.1.a, dry bottom boilers using residual 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)					
Technologies/Practices	Dry Bottom Boilers				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, PCB, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	210	g/GJ	130	300	CITEPA 1992
CO	15.1	g/GJ	9.1	21	US EPA 1998, chapter 1.3
NMVOC	2.3	g/GJ	1.4	3.2	US EPA 1998, chapter 1.3
SO_x	485	g/GJ	146	1699	See Note
TSP	20	g/GJ	2.0	200	Expert judgement based on Visschedijk et al (2004)
PM_{10}	15	g/GJ	1.5	150	Expert judgement based on Visschedijk et al (2004)
$PM_{2.5}$	9.0	g/GJ	0.9	90	Expert judgement based on Visschedijk et al (2004)
Pb	4.6	mg/GJ	2.3	9.1	US EPA 1998, chapter 1.3
Cd	1.2	mg/GJ	0.6	2.4	US EPA 1998, chapter 1.3
Hg	0.3	mg/GJ	0.2	0.7	US EPA 1998, chapter 1.3
As	4.0	mg/GJ	2.0	8.0	US EPA 1998, chapter 1.3
Cr	2.5	mg/GJ	1.3	5.1	US EPA 1998, chapter 1.3
Cu	5.3	mg/GJ	2.7	11	US EPA 1998, chapter 1.3
Ni	255	mg/GJ	127	510	US EPA 1998, chapter 1.3
Se	2.1	mg/GJ	1.0	4.1	US EPA 1998, chapter 1.3
Zn	88	mg/GJ	44	176	US EPA 1998, chapter 1.3
PCDD/F	2.5	ng I-TEQ/GJ	1.3	3.8	UNEP (2005); Heavy fuel fired power boilers
Indeno(1,2,3-cd)pyrene	6.9	µg/GJ	3.5	13.8	US EPA 1998, chapter 1.3

Note:

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.

Table 3-14 Tier 2 emission factors for source category 1.A.1.a, dry bottom 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)					
Technologies/Practices	Dry Bottom Boilers				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, PCB, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	89	g/GJ	15	185	US EPA 1998, chapter 1.4
CO	39	g/GJ	20	60	US EPA 1998, chapter 1.4
NMVOC	1.5	g/GJ	0.8	6.0	US EPA 1998, chapter 1.4
SO_x	0.3	g/GJ	0.2	0.4	US EPA 1998, chapter 1.4
TSP	0.9	g/GJ	0.4	1.3	US EPA 1998, chapter 1.4
PM_{10}	0.9	g/GJ	0.4	1.3	US EPA 1998, chapter 1.4
$PM_{2.5}$	0.9	g/GJ	0.4	1.3	US EPA 1998, chapter 1.4
Pb	0.2	mg/GJ	0.1	0.7	US EPA 1998, chapter 1.4
Cd	0.5	mg/GJ	0.2	1.6	US EPA 1998, chapter 1.4
Hg	0.1	mg/GJ	0.05	0.15	van der Most & Veldt 1992
As	0.09	mg/GJ	0.03	0.28	US EPA 1998, chapter 1.4
Cr	0.7	mg/GJ	0.2	2.0	US EPA 1998, chapter 1.4
Cu	0.4	mg/GJ	0.2	0.8	US EPA 1998, chapter 1.4
Ni	1.0	mg/GJ	0.5	2.0	US EPA 1998, chapter 1.4
Se	0.01	mg/GJ	0.004	0.03	US EPA 1998, chapter 1.4
Zn	14	mg/GJ	4.5	41	US EPA 1998, chapter 1.4
PCDD/F	0.5	ng I-TEQ/GJ	0.3	0.8	UNEP (2005); Light fuel oil/natural gas fired power boilers
Benzo(a)pyrene	0.6	µg/GJ	0.2	0.6	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(b)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(k)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Indeno(1,2,3-cd)pyrene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)

Notes:

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

Emission factor for PCDD/F is stated to be applicable light fuel oil and natural gas use in power station boilers, but is based mainly on data from oil combustion. UNEP also reports limited data for gas combustion of between 0.02 and 0.03 ng TEQ/GJ for natural gas-fired boilers.

Table 3-15 Tier 2 emission factors for source category 1.A.1.a, dry bottom boilers using 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)					
Technologies/Practices	Dry Bottom Boilers				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	211	g/GJ	55	420	US EPA 2003, chapter 1.6
CO	258	g/GJ	155	360	US EPA 2003, chapter 1.6
NMVOC	7.3	g/GJ	2.4	22	US EPA 2003, chapter 1.6
SO_x	11	g/GJ	6.5	15	US EPA 2003, chapter 1.6
TSP	35	g/GJ	12	697	Expert judgement based on Visschedijk et al (2004)
PM_{10}	25	g/GJ	5.7	645	Expert judgement based on Visschedijk et al (2004)
$PM_{2.5}$	12	g/GJ	5.2	555	Expert judgement based on Visschedijk et al (2004)
Pb	21	mg/GJ	12	29	US EPA 2003, chapter 1.6
Cd	1.8	mg/GJ	1.1	2.5	US EPA 2003, chapter 1.6
Hg	1.5	mg/GJ	0.9	2.1	US EPA 2003, chapter 1.6
As	9.5	mg/GJ	5.7	13	US EPA 2003, chapter 1.6
Cr	9.0	mg/GJ	5.4	13	US EPA 2003, chapter 1.6
Cu	21	mg/GJ	13	29	US EPA 2003, chapter 1.6
Ni	14	mg/GJ	8.5	20	US EPA 2003, chapter 1.6
Se	1.2	mg/GJ	0.7	1.7	US EPA 2003, chapter 1.6
Zn	181	mg/GJ	108	253	US EPA 2003, chapter 1.6
PCB	60	µg/GJ	30	90	Kakareka et. al (2004)
PCDD/F	50	ng I-TEQ/GJ	25	75	UNEP (2005) (for clean wood)
Benzo(a)pyrene	1.1	mg/GJ	0.7	1.6	US EPA 2003, chapter 1.6
Benzo(b)fluoranthene	0.04	mg/GJ	0.02	0.06	US EPA 2003, chapter 1.6
Benzo(k)fluoranthene	0.015	mg/GJ	0.008	0.023	US EPA 2003, chapter 1.6
Indeno(1,2,3-cd)pyrene	0.37	mg/GJ	0.19	0.56	US EPA 2003, chapter 1.6
HCB	6.0	µg/GJ	3.0	9.0	Guidebook (2006)

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)					
Technologies/Practices	Wet Bottom Boilers				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, Benzo(b)fluoranthene, Benzo(k)fluoranthene				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	461	g/GJ	290	635	US EPA 1998, chapter 1.1
CO	10	g/GJ	6	150	US EPA 1998, chapter 1.1
NMVOC	0.8	g/GJ	0.4	1.6	US EPA 1998, chapter 1.1
SO_x	820	g/GJ	330	5000	See note
TSP	15	g/GJ	7.5	30	Expert judgement based on Visschedijk et al (2004)
PM_{10}	12	g/GJ	6	24	Expert judgement based on Visschedijk et al (2004)
$PM_{2.5}$	6	g/GJ	3	12	Expert judgement based on Visschedijk et al (2004)
Pb	8.6	mg/GJ	5.2	12	US EPA 1998, chapter 1.1
Cd	1.1	mg/GJ	0.6	1.5	US EPA 1998, chapter 1.1
Hg	1.7	mg/GJ	1.0	2.4	US EPA 1998, chapter 1.1
As	8.4	mg/GJ	5.0	12	US EPA 1998, chapter 1.1
Cr	5.3	mg/GJ	3.2	7.5	US EPA 1998, chapter 1.1
Cu	4.8	mg/GJ	0.2	16	Expert judgement, derived from Guidebook (2006)
Ni	5.7	mg/GJ	3.4	8.0	US EPA 1998, chapter 1.1
Se	27	mg/GJ	16	37	US EPA 1998, chapter 1.1
Zn	19	mg/GJ	0.4	155	Expert judgement, derived from Guidebook (2006)
PCB	170	µg/GJ	85	260	Kakareka et. al (2004)
PCDD/F	10	ng I-TEQ/GJ	5.0	15	UNEP (2005); Coal fired power boilers
Benzo(a)pyrene	0.7	µg/GJ	0.2	2.2	US EPA 1998, chapter 1.1
Indeno(1,2,3-cd)pyrene	1.2	µg/GJ	0.6	2.4	US EPA 1998, chapter 1.1
HCB	0.62	µg/GJ	0.3	0.9	Guidebook (2006)

Note:

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.

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)					
Technologies/Practices	Fluid Bed Boilers				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, Benzo(b)fluoranthene, Benzo(k)fluoranthene				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	83	g/GJ	10	112	EIPPCB 2006
CO	70	g/GJ	0.7	150	CITEPA 1992
NMVOC	1.2	g/GJ	0.6	2.4	US EPA 1998, chapter 1.1
SO_x	820	g/GJ	330	5000	See Note
TSP	15	g/GJ	8	30	Expert judgement scaled from Visschedijk et al (2004), assumes 50mg/m3 TSP
PM_{10}	12	g/GJ	6	24	Expert judgement scaled from Visschedijk et al (2004), assumes 50mg/m3 TSP
$PM_{2.5}$	6	g/GJ	3	12	Expert judgement scaled from Visschedijk et al (2004), assumes 50mg/m3 TSP
Pb	8.1	mg/GJ	4.9	11.4	US EPA 1998, chapter 1.1
Cd	1.0	mg/GJ	0.6	1.4	US EPA 1998, chapter 1.1
Hg	1.6	mg/GJ	1.0	2.3	US EPA 1998, chapter 1.1
As	8.0	mg/GJ	4.8	11.1	US EPA 1998, chapter 1.1
Cr	5.0	mg/GJ	3.0	7.1	US EPA 1998, chapter 1.1
Cu	4.8	mg/GJ	0.2	15.5	Expert judgement, derived from Guidebook (2006)
Ni	5.4	mg/GJ	3.3	7.6	US EPA 1998, chapter 1.1
Se	25	mg/GJ	15	35	US EPA 1998, chapter 1.1
Zn	19	mg/GJ	0.4	155	Expert judgement, derived from Guidebook (2006)
PCB	170	µg/GJ	85	260	Kakareka et. al (2004)
PCDD/F	10	ng I-TEQ/GJ	5	15	UNEP (2005); Coal fired power boilers
Benzo(a)pyrene	0.7	µg/GJ	0.2	2.2	US EPA 1998, chapter 1.1
Indeno(1,2,3-cd)pyrene	1.2	µg/GJ	0.6	2.4	US EPA 1998, chapter 1.1
HCB	0.62	µg/GJ	0.3	0.9	Guidebook (2006)

Note:

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.

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)					
Technologies/Practices	Fluid Bed Boilers				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, PCB, Benzo(b)fluoranthene, Benzo(k)fluoranthene, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	61	g/GJ	35	85	EIPPCB 2006
CO	0.07	g/GJ	0.04	0.10	EIPPCB 2006
NMVOC	1.7	g/GJ	0.8	3.4	US EPA 1998, chapter 1.7
SO_x	820	g/GJ	330	5000	See Note
TSP	40	g/GJ	25	60	Expert judgement, derived from Guidebook (2006)
PM_{10}	30	g/GJ	18	42	Expert judgement, derived from Guidebook (2006)
$PM_{2.5}$	14	g/GJ	8.4	20	Expert judgement, derived from Guidebook (2006)
Pb	18	mg/GJ	11	25	US EPA 1998, chapter 1.7
Cd	2.1	mg/GJ	1.3	3.0	US EPA 1998, chapter 1.7
Hg	3.5	mg/GJ	2.1	4.9	US EPA 1998, chapter 1.7
As	17	mg/GJ	10	24	US EPA 1998, chapter 1.7
Cr	11	mg/GJ	6.6	15	US EPA 1998, chapter 1.7
Cu	0.3	mg/GJ	0.1	0.8	Expert judgement, derived from Guidebook (2006)
Ni	12	mg/GJ	7.1	16	US EPA 1998, chapter 1.7
Se	55	mg/GJ	33	76	US EPA 1998, chapter 1.7
Zn	4.5	mg/GJ	0.5	17	Expert judgement, derived from Guidebook (2006)
PCDD/F	10	ng I-TEQ/GJ	5	15	UNEP (2005); Coal fired power boilers
Benzo(a)pyrene	0.8	µg/GJ	0.3	2.3	US EPA 1998, chapter 1.7
Indeno(1,2,3-cd)pyrene	1.3	µg/GJ	0.6	2.5	US EPA 1998, chapter 1.7

Note:

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.

Table 3-19 Tier 2 emission factors for source category 1.A.1.a, fluid bed boilers using wood and similar wood wastes.

Tier 2 emission factors		
	Code	Name
NFR Source Category	1.A.1.a	Public electricity and heat production
Fuel	Wood and similar wood wastes	
SNAP (if applicable)		
Technologies/Practices	Fluid Bed Boilers	
Region or regional conditi	NA	
Abatement technologies	NA	
Not estimated	NH_3	
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP	

Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	96	g/GJ	30	300	Kubica et al (2003)
CO	42	g/GJ	14	125	Kubica et al (2003)
NMVOC	7.3	g/GJ	2.4	22	US EPA 2003, chapter 1.6
SO_x	11	g/GJ	6.5	15	US EPA 2003, chapter 1.6
TSP	35	g/GJ	3.5	350	Expert judgement scaled from Visschedijk et al (2004), assumes 50mg/m3 TSP
PM_{10}	25	g/GJ	2.5	250	Expert judgement scaled from Visschedijk et al (2004), assumes 50mg/m3 TSP
$PM_{2.5}$	12	g/GJ	1.2	120	Expert judgement scaled from Visschedijk et al (2004), assumes 50mg/m3 TSP
Pb	21	mg/GJ	12	29	US EPA 2003, chapter 1.6
Cd	1.8	mg/GJ	1.1	2.5	US EPA 2003, chapter 1.6
Hg	1.5	mg/GJ	0.9	2.1	US EPA 2003, chapter 1.6
As	9.5	mg/GJ	5.7	13.2	US EPA 2003, chapter 1.6
Cr	9.0	mg/GJ	5.4	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	8.5	19.9	US EPA 2003, chapter 1.6
Se	1.2	mg/GJ	0.7	1.7	US EPA 2003, chapter 1.6
Zn	181	mg/GJ	108	253	US EPA 2003, chapter 1.6
PCB	60	µg/GJ	30	90	Kakareka et. al (2004)
PCDD/F	50	ng I-TEQ/GJ	25	75	UNEP (2005) (for clean wood)
Benzo(a)pyrene	1.1	mg/GJ	0.7	1.6	US EPA 2003, chapter 1.6
Benzo(b)fluoranthene	0.04	mg/GJ	0.02	0.06	US EPA 2003, chapter 1.6
Benzo(k)fluoranthene	0.02	mg/GJ	0.01	0.02	US EPA 2003, chapter 1.6
Indeno(1,2,3-cd)pyrene	0.37	mg/GJ	0.2	0.6	US EPA 2003, chapter 1.6
HCB	6	µg/GJ	3.0	9.0	Guidebook (2006)

Table 3-20 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 conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, PCB, PCDD/F, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	153	g/GJ	92	245	US EPA 2000, chapter 3.1
CO	39	g/GJ	24	63	US EPA 2000, chapter 3.1
NMVOC	1.0	g/GJ	0.3	3	US EPA 2000, chapter 3.1
SO_x	0.3	g/GJ	0.2	0.4	US EPA 1998, chapter 1.4
TSP	0.9	g/GJ	0.5	1.8	US EPA 2000, chapter 3.1
PM_{10}	0.9	g/GJ	0.5	1.8	US EPA 2000, chapter 3.1
$PM_{2.5}$	0.9	g/GJ	0.5	1.8	US EPA 2000, chapter 3.1
Pb	0.2	mg/GJ	0.1	0.7	US EPA 2000, chapter 3.1
Cd	0.5	mg/GJ	0.2	1.5	US EPA 1998, chapter 1.4
Hg	0.10	mg/GJ	0.05	0.15	van der Most & Veldt 1992
As	0.1	mg/GJ	0.03	0.3	US EPA 1998, chapter 1.4
Cr	0.7	mg/GJ	0.2	2.0	US EPA 1998, chapter 1.4
Cu	0.4	mg/GJ	0.2	0.8	US EPA 1998, chapter 1.4
Ni	1.0	mg/GJ	0.5	2.0	US EPA 1998, chapter 1.4
Se	0.01	mg/GJ	0.004	0.03	US EPA 1998, chapter 1.4
Zn	14	mg/GJ	4.5	40	US EPA 1998, chapter 1.4
Benzo(a)pyrene	0.6	µg/GJ	0.2	0.6	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(b)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(k)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Indeno(1,2,3-cd)pyrene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)

Note:

Factor for SO_x is based on approximately 0.01 g/m3 mass sulphur content. SO_2 emission factor can also be calculated using EF calculation from subsection 3.4.2.2 of the present chapter.

Table 3-21 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)	010105	Public power - Stationary engines			
Technologies/Practices	Gas Turbines				
Region or regional conditi	NA				
Abatement technologies	NA				
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				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	398	g/GJ	239	557	US EPA 2000, chapter 3.1
CO	1.5	g/GJ	0.89	2.1	US EPA 2000, chapter 3.1
NMVOC	0.2	g/GJ	0.11	0.26	US EPA 2000, chapter 3.1
SO_x	46	g/GJ	4.61	460	See Note
TSP	3.0	g/GJ	1.5	6.0	Rubenstein (2003)
PM_{10}	3.0	g/GJ	1.5	6.0	Rubenstein (2003)
$PM_{2.5}$	3.0	g/GJ	1.5	6.0	Rubenstein (2003)
Pb	6.3	mg/GJ	2.1	19.0	US EPA 2000, chapter 3.1
Cd	2.2	mg/GJ	0.7	6.5	US EPA 2000, chapter 3.1
Hg	0.5	mg/GJ	0.2	1.6	US EPA 2000, chapter 3.1
Cr	5.0	mg/GJ	1.7	14.9	US EPA 2000, chapter 3.1

Note:

Based on 0.1 % mass sulphur content.

Table 3-22 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 conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, PCB, PCDD/F, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	1450	g/GJ	680	2050	US EPA 1996, chapter 3.3
CO	385	g/GJ	193	578	US EPA 1996, chapter 3.3
NMVOC	37	g/GJ	19	56	US EPA 1996, chapter 3.3
SO_x	46	g/GJ	4.6	461	See note
TSP	28.1	g/GJ	14.1	56.2	US EPA 1996, chapter 3.3
PM_{10}	22.4	g/GJ	11.2	44.8	US EPA 1996, chapter 3.3
$PM_{2.5}$	21.7	g/GJ	10.9	43	US EPA 1996, chapter 3.3
Pb	4.1	mg/GJ	0.4	41	US EPA 1998, chapter 1.3
Cd	1.4	mg/GJ	0.1	14	US EPA 1998, chapter 1.3
Hg	1.4	mg/GJ	0.1	14	US EPA 1998, chapter 1.3
As	1.8	mg/GJ	0.2	18	US EPA 1998, chapter 1.3
Cr	1.4	mg/GJ	0.1	14	US EPA 1998, chapter 1.3
Cu	2.7	mg/GJ	0.3	27	US EPA 1998, chapter 1.3
Ni	1.4	mg/GJ	0.1	14	US EPA 1998, chapter 1.3
Se	6.8	mg/GJ	0.7	68	US EPA 1998, chapter 1.3
Zn	1.8	mg/GJ	0.2	18	US EPA 1998, chapter 1.3
Benzo(a)pyrene	0.12	mg/GJ	0.06	0.12	US EPA 1996, chapter 3.3 ("Less than" value based on method detection limits)
Benzo(b)fluoranthene	0.50	mg/GJ	0.25	0.75	US EPA 1996, chapter 3.3
Benzo(k)fluoranthene	0.10	mg/GJ	0.05	0.10	US EPA 1996, chapter 3.3 ("Less than" value based on method detection limits)
Indeno(1,2,3-cd)pyrene	0.19	mg/GJ	0.09	0.19	US EPA 1996, chapter 3.3 ("Less than" value based on method detection limits)

Notes:

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.

TSP is based on AP-42 factor for PM10.

Table 3-23 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	Gas fuel (includes dual fuel 95% gas + 5% gas oil)	
SNAP (if applicable)	010105	Public power - Stationary engines
Technologies/Practices	Stationary reciprocating Engines - gas-fired, includes dual fuel	
Region or regional conditi	NA	
Abatement technologies	NA	
Not estimated	NH_3, PCB, PCDD/F, HCB	
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCP, SCCP	

Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	1416	g/GJ	708	2124	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2
CO	407	g/GJ	204	611	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2
NMVOC	46	g/GJ	23	69	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2
SO_x	0.3	g/GJ	0.2	0.4	US EPA 1998, chapter 1.4
TSP	1.5	g/GJ	0.01	20	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2
PM_{10}	1.5	g/GJ	0.01	20	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2
$PM_{2.5}$	1.5	g/GJ	0.01	20	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2
Pb	0.2	mg/GJ	0.1	0.7	US EPA 1998, chapter 1.4
Cd	0.5	mg/GJ	0.2	1.5	US EPA 1998, chapter 1.4
Hg	0.10	mg/GJ	0.05	0.15	van der Most & Veldt 1992
As	0.09	mg/GJ	0.03	0.3	US EPA 1998, chapter 1.4
Cr	0.7	mg/GJ	0.2	2.0	US EPA 1998, chapter 1.4
Cu	0.4	mg/GJ	0.2	0.8	US EPA 1998, chapter 1.4
Ni	1.0	mg/GJ	0.5	2.0	US EPA 1998, chapter 1.4
Se	0.01	mg/GJ	0.004	0.03	US EPA 1998, chapter 1.4
Zn	14	mg/GJ	4.5	41	US EPA 1998, chapter 1.4
Benzo(a)pyrene	0.0027	mg/GJ	0.001	0.004	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2
Benzo(b)fluoranthene	0.018	mg/GJ	0.009	0.03	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2
Benzo(k)fluoranthene	0.002	mg/GJ	0.001	0.003	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2
Indeno(1,2,3-cd)pyrene	0.0047	mg/GJ	0.002	0.007	Expert judgement based on US EPA 1996, chapter 3.4 and 2000, chapter 3.2

Notes:

Factor for SO_x is based on approximately 0.01 g/m3 mass sulphur content. SO_2 emission factor can also be calculated using EF calculation from subsection 3.4.2.2 of the present chapter.

TSP and PM2.5 factors are based on AP-42 factor PM10.

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:

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

- 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.

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. 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.

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, 2003).

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). In addition, process sources include bitumen blowing, blowdown systems, hydrogen plant, fluid coking units, fluidised catalytic cracking (FCC) units and catalytic reforming units.

4.2 Emissions

The contributions of point source emissions released by combustion plants to the total emissions reported by countries to the CLRTAP emission database (WebDab) are given in Table 4-1:

Table 4-1 Contributions (%) of emissions from petroleum refining activities to total emissions of the WebDab2005

NFR Code	Data	SO_x	NO_x	NMVOC	CO	NH3	PM_{10}	$PM_{2.5}$	TSP
1.A.1.b — Petroleum refining	No. of countries reporting	33	33	33	32	33	32	33	32
	Lowest value	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Typical contribution	5.7	1.0	0.2	0.1	0.0	0.5	0.6	0.3
	Highest value	47.3	5.3	4.8	0.6	0.1	2.4	3.4	1.5

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.

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).

Non-methane volatile organic compounds (NMVOC)

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

Carbon monoxide (CO)

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

Ammonia (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.

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.

Metals

According to the BREF, important heavy metals in crude oils are As, Hg, Ni, and V. Concawe (Concawe, 2009) 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.

Methane (CH_4)

Refer to IPCC guidance.

Carbon Dioxide (CO_2)

Refer to IPCC guidance.

Nitrous Oxide (N_2O)

Refer to IPCC guidance.

4.3 Controls

Details of relevant abatement technologies are described in the BREF notes for refineries and large combustion plant http://eippcb.jrc.es/pages/FActivities.htm. 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.

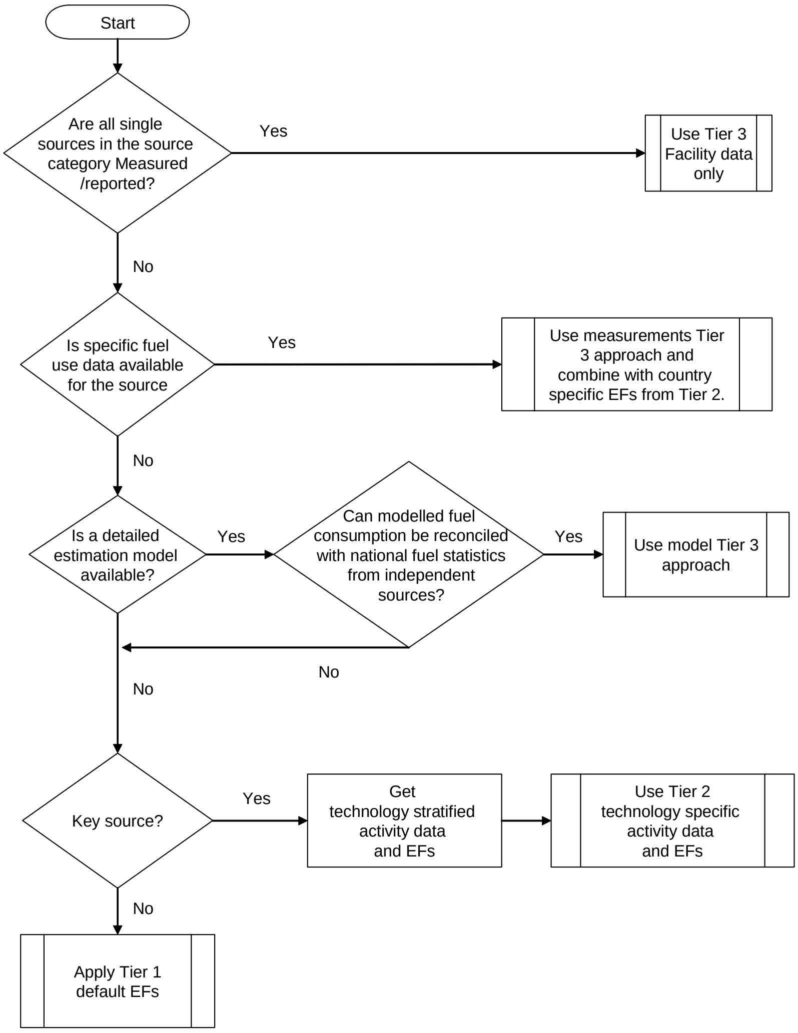

Figure 4-1 **Decision tree for combustion in petroleum refining**

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 for natural gas.

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 types including fuel types common with the 1.A.1.a activity. As most combustion is in process furnaces without contact with the material being heated, Tier 1 default factors for refinery combustion can often be drawn from the 1.A.1.a Tier 1 default factors classifications (see Table 4-2).

Table 4-2 Tier 1 fuel classifications

Tier 1 fuel type	**Associated fuel types**	**Location**
Natural gas	Natural gas	See 1.A.l.a Tier 1
Heavy fuel oil	Residual fuel oil, refinery feedstock, petroleum coke	See 1.A.1.a Tier 1
Other liquid fuels	(a) Gas oil, kerosene, naphtha, natural gas liquids, liquefied petroleum gas, orimulsion, bitumen, shale oil (b) refinery gas	(a) See 1.A.1.a Tier 1 (b) Table 4-3

The Tier 1 default emission factors for refinery gas as given in Table 4-3 have been derived from emission factors published by USEPA (USEPA, 1998) and elsewhere including factors incorporated by the industry sector (Concawe, 2009). In the absence of detail on relative use of combustion or abatement technology, which will be different for each country, the proposed factors represent a mean for the range of technologies in use with the 95 % figures a measure of the range of emissions in the sector.

An emission factor for sulphur oxides is provided in the Tier 1 table, but this is based on a range of published factors, some of which represent very different sulphur levels in the fuels. Where countries have knowledge of fuel sulphur content then it is recommended that a sulphur oxides emission factor is calculated from fuel sulphur content.

Table 4-3 Tier 1 emission factors for source category 1.A.1.b, refinery gas

Tier 1 default emission factors					
	Code	Name			
NFR Source Category	1.A.1.b	Petroleum refining			
Fuel	Refinery Gas				
Not estimated	NH_3, Se, Zn, PCDD/F, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	60	g/GJ	36	84	US EPA 1998, chapter 1.4
CO	39	g/GJ	24	55	US EPA 1998, chapter 1.4
NMVOC	2.6	g/GJ	1.3	5.2	US EPA 1998, chapter 1.4
SO_x	0.3	g/GJ	0.17	0.39	US EPA 1998, chapter 1.4
TSP	0.89	g/GJ	0.30	2.7	US EPA 1998, chapter 1.4
PM_{10}	0.89	g/GJ	0.30	2.7	US EPA 1998, chapter 1.4
$PM_{2.5}$	0.89	g/GJ	0.30	2.7	US EPA 1998, chapter 1.4
Pb	1.8	mg/GJ	0.9	3.6	API (1998, 2002)
Cd	0.71	mg/GJ	0.36	1.4	API (1998, 2002)
Hg	0.09	mg/GJ	0.04	0.17	API (1998, 2002)
As	0.34	mg/GJ	0.17	0.69	API (1998, 2002)
Cr	2.7	mg/GJ	1.4	5.5	API (1998, 2002)
Cu	2.2	mg/GJ	1.1	4.4	API (1998, 2002)
Ni	3.6	mg/GJ	1.8	7.2	API (1998, 2002)
Benzo(a)pyrene	0.67	µg/GJ	0.22	2.0	API (1998, 2002)
Benzo(b)fluoranthene	1.1	µg/GJ	0.4	3.4	API (1998, 2002)
Benzo(k)fluoranthene	0.63	µg/GJ	0.21	1.9	API (1998, 2002)
Indeno(1,2,3-cd)pyrene	0.63	µg/GJ	0.21	1.9	API (1998, 2002)

Note:

Factor for SO_x is based on approximately 0.01 gm3 mass sulphur content. SO_2 emission factor can also be calculated using EF calculation from subsection 3.4.2.2 of the present chapter.

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).

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]).

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.es/pages/FActivities.htm 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, 2009) and represent unabated emission factors.

Emission factors for sulphur oxides are generally not provided in the Tier 2 tables but, where no abatement is applied, can be derived from the fuel sulphur content (see 1.A.1.a). Where countries have knowledge of fuel sulphur content then it is recommended that a sulphur oxides emission factor is calculated from fuel sulphur content.

A methodology to calculate NO_x emissions has been provided in Concawe, 2009 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.

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

Table 4-4 Tier 2 default factors

Technology	**Associated fuel types**	**Location of Tier 2 factors**
Process furnaces	Residual oil	Table 4-5
	Gas oil	Table 4-6
	LPG	Table 4-7
	Refinery gas	See Tier 1 (Table 4-3)
	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

Table 4-5 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 conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, Se, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, Indeno(1,2,3-cd)pyrene , HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	125	g/GJ	60	330	US EPA 1998, chapter 1.3
CO	15	g/GJ	9.1	21	US EPA 1998, chapter 1.3
NMVOC	2.3	g/GJ	0.7	4.1	US EPA 1998, chapter 1.3
SO_x	485	g/GJ	146	1700	See Note
TSP	20	g/GJ	12	28	Expert judgement based on Visschedijk et al (2004)
PM_{10}	15	g/GJ	9	21	Expert judgement based on Visschedijk et al (2004)
$PM_{2.5}$	9	g/GJ	5	13	Expert judgement based on Visschedijk et al (2004)
Pb	4.6	mg/GJ	0.9	23	US EPA 1998, chapter 1.3
Cd	1.2	mg/GJ	0.2	6.0	US EPA 1998, chapter 1.3
Hg	0.11	mg/GJ	0.02	0.57	US EPA 1998, chapter 1.3
As	4.0	mg/GJ	0.8	20	US EPA 1998, chapter 1.3
Cr	15	mg/GJ	3.0	74	API (1998, 2002)
Cu	12	mg/GJ	2.4	60	API (1998, 2002)
Ni	1030	mg/GJ	206	5150	API (1998, 2002)
Zn	49	mg/GJ	10	247	API (1998, 2002)
PCDD/F	2.5	ng I-TEQ/GJ	1.3	3.8	UNEP (2005); Heavy fuel fired power boilers

Note:

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.

Table 4-6 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 conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, PCDD/F, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, Indeno(1,2,3-cd)pyrene, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	60	g/GJ	20	80	US EPA 1998, chapter 1.3
CO	16	g/GJ	5.4	50	US EPA 1998, chapter 1.3
NMVOC	1.1	g/GJ	0.5	3.0	US EPA 1998, chapter 1.3
SO_x	46	g/GJ	37	460	See Note
TSP	6.5	g/GJ	1.3	32	US EPA 1998, chapter 1.3
PM_{10}	3.2	g/GJ	0.6	16	US EPA 1998, chapter 1.3
$PM_{2.5}$	0.8	g/GJ	0.2	4.0	US EPA 1998, chapter 1.3
Pb	4.1	mg/GJ	2.0	8.1	US EPA 1998, chapter 1.3
Cd	1.4	mg/GJ	0.7	2.7	US EPA 1998, chapter 1.3
Hg	1.4	mg/GJ	0.7	2.7	US EPA 1998, chapter 1.3
As	1.8	mg/GJ	0.9	3.6	US EPA 1998, chapter 1.3
Cr	1.4	mg/GJ	0.7	2.7	US EPA 1998, chapter 1.3
Cu	2.7	mg/GJ	1.4	5.4	US EPA 1998, chapter 1.3
Ni	1.4	mg/GJ	0.7	2.7	US EPA 1998, chapter 1.3
Se	6.8	mg/GJ	0.7	68	US EPA 1998, chapter 1.3
Zn	1.8	mg/GJ	0.9	3.6	US EPA 1998, chapter 1.3

Note:

Based on 0.1 % mass sulphur content.

Table 4-7 Tier 2 emission factors for source category 1.A.1.b, process furnaces using liquid petroleum gas

Tier 2 emission factors					
	Code	Name			
NFR Source Category	1.A.1.b	Petroleum refining			
Fuel	LPG				
SNAP (if applicable)	0103	Petroleum refining plants			
Technologies/Practices	Process Furnaces, Heaters and Boilers				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	64	g/GJ	13	322	US EPA 2008, chapter 1.5
CO	37	g/GJ	7.4	185	US EPA 2008, chapter 1.5
NMVOC	4.0	g/GJ	0.8	19.8	US EPA 2008, chapter 1.5
SO_x	0.3	g/GJ	0.17	0.39	US EPA 1998, chapter 1.4
TSP	0.99	g/GJ	0.20	4.9	US EPA 2008, chapter 1.5
PM_{10}	0.99	g/GJ	0.20	4.9	US EPA 2008, chapter 1.5
$PM_{2.5}$	0.99	g/GJ	0.20	4.9	US EPA 2008, chapter 1.5
Pb	0.2	mg/GJ	0.1	0.7	US EPA 1998, chapter 1.4
Cd	0.5	mg/GJ	0.2	1.6	US EPA 1998, chapter 1.4
Hg	0.10	mg/GJ	0.05	0.15	van der Most & Veldt 1992
As	0.09	mg/GJ	0.03	0.28	US EPA 1998, chapter 1.4
Cr	0.7	mg/GJ	0.2	2.0	US EPA 1998, chapter 1.4
Cu	0.4	mg/GJ	0.2	0.8	US EPA 1998, chapter 1.4
Ni	1.0	mg/GJ	0.5	2.0	US EPA 1998, chapter 1.4
Se	0.01	mg/GJ	0.004	0.03	US EPA 1998, chapter 1.4
Zn	14	mg/GJ	4.5	41	US EPA 1998, chapter 1.4
Benzo(a)pyrene	0.6	µg/GJ	0.2	0.6	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(b)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(k)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Indeno(1,2,3-cd)pyrene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)

Note:

Factor for SO_x is based on approximately 0.01 g/m^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.

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 conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	60	g/GJ	35.81	83.55	US EPA 1998, chapter 1.4
CO	39	g/GJ	23.60	55.08	US EPA 1998, chapter 1.4
NMVOC	2.6	g/GJ	1.29	5.16	US EPA 1998, chapter 1.4
SO_x	0.3	g/GJ	0.17	0.39	US EPA 1998, chapter 1.4
TSP	0.89	g/GJ	0.30	2.67	US EPA 1998, chapter 1.4
PM_{10}	0.89	g/GJ	0.30	2.67	US EPA 1998, chapter 1.4
$PM_{2.5}$	0.89	g/GJ	0.30	2.67	US EPA 1998, chapter 1.4
Pb	0.2	mg/GJ	0.08	0.70	US EPA 1998, chapter 1.4
Cd	0.5	mg/GJ	0.2	1.6	US EPA 1998, chapter 1.4
Hg	0.10	mg/GJ	0.1	0.2	van der Most & Veldt 1992
As	0.09	mg/GJ	0.0	0.3	US EPA 1998, chapter 1.4
Cr	0.7	mg/GJ	0.2	1.97	US EPA 1998, chapter 1.4
Cu	0.4	mg/GJ	0.2	0.80	US EPA 1998, chapter 1.4
Ni	1.0	mg/GJ	0.5	1.97	US EPA 1998, chapter 1.4
Se	0.01	mg/GJ	0.0	0.03	US EPA 1998, chapter 1.4
Zn	14	mg/GJ	4.5	41	US EPA 1998, chapter 1.4
Benzo(a)pyrene	0.6	µg/GJ	0.2	0.6	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(b)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(k)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Indeno(1,2,3-cd)pyrene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)

Note:

Factor for SO_x is based on approximately 0.01 g/m^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.

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	Reciprocating Engines - gas fired				
Region or regional conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	410	g/GJ	200	810	US EPA 2000, chapter 3.2; refers to 4 stroke lean burn engines
CO	270	g/GJ	130	530	US EPA 2000, chapter 3.2; refers to 4 stroke lean burn engines
NMVOC	60	g/GJ	30	110	US EPA 2000, chapter 3.2; refers to 4 stroke lean burn engines
SO_x	0.3	g/GJ	0.17	0.39	US EPA 2000, chapter 3.2; refers to 4 stroke lean burn engines
TSP	0.89	g/GJ	0.30	2.67	US EPA 1998, chapter 1.4
PM_{10}	0.89	g/GJ	0.30	2.67	US EPA 1998, chapter 1.4
$PM_{2.5}$	0.89	g/GJ	0.30	2.67	US EPA 1998, chapter 1.4
Pb	0.2	mg/GJ	0.1	0.70	US EPA 1998, chapter 1.4
Cd	0.5	mg/GJ	0.17	1.55	US EPA 1998, chapter 1.4
Hg	0.1	mg/GJ	0.05	0.15	van der Most & Veldt 1992
As	0.09	mg/GJ	0.03	0.28	US EPA 1998, chapter 1.4
Cr	0.66	mg/GJ	0.2	2.0	US EPA 1998, chapter 1.4
Cu	0.4	mg/GJ	0.2	0.8	US EPA 1998, chapter 1.4
Ni	1.0	mg/GJ	0.5	2.0	US EPA 1998, chapter 1.4
Se	0.01	mg/GJ	0	0	US EPA 1998, chapter 1.4
Zn	14	mg/GJ	5	41	US EPA 1998, chapter 1.4
Benzo(a)pyrene	0.6	µg/GJ	0.2	0.6	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(b)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Benzo(k)fluoranthene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)
Indeno(1,2,3-cd)pyrene	0.8	µg/GJ	0.3	0.8	US EPA 1998, chapter 1.4 ("Less than" value based on method detection limits)

Note:

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.

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 conditi	NA				
Abatement technologies	NA				
Not estimated	NH_3, PCDD/F, HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	1450	g/GJ	680	2050	US EPA 1996, chapter 3.3
CO	385	g/GJ	193	578	US EPA 1996, chapter 3.3
NMVOC	37	g/GJ	19	56	US EPA 1996, chapter 3.3
SO_x	46	g/GJ	4.6	461	See note
TSP	28.1	g/GJ	14.1	56.2	US EPA 1996, chapter 3.3
PM_{10}	22.4	g/GJ	11.2	44.8	US EPA 1996, chapter 3.3
$PM_{2.5}$	21.7	g/GJ	10.9	43	US EPA 1996, chapter 3.3
Pb	4.07	mg/GJ	0.4	41	US EPA 1998, chapter 1.3
Cd	1.4	mg/GJ	0.1	14	US EPA 1998, chapter 1.3
Hg	1.4	mg/GJ	0.1	14	US EPA 1998, chapter 1.3
As	1.8	mg/GJ	0.2	18	US EPA 1998, chapter 1.3
Cr	1.4	mg/GJ	0.1	14	US EPA 1998, chapter 1.3
Cu	2.7	mg/GJ	0.3	27	US EPA 1998, chapter 1.3
Ni	1.4	mg/GJ	0.1	14	US EPA 1998, chapter 1.3
Se	6.8	mg/GJ	0.7	68	US EPA 1998, chapter 1.3
Zn	1.8	mg/GJ	0.2	18	US EPA 1998, chapter 1.3
Benzo(a)pyrene	0.12	mg/GJ	0.06	0.12	US EPA 1996, chapter 3.3 ("Less than" value based on method detection limits)
Benzo(b)fluoranthene	0.50	mg/GJ	0.25	0.75	US EPA 1996, chapter 3.3
Benzo(k)fluoranthene	0.10	mg/GJ	0.05	0.10	US EPA 1996, chapter 3.3 ("Less than" value based on method detection limits)
Indeno(1,2,3-cd)pyrene	0.19	mg/GJ	0.09	0.19	US EPA 1996, chapter 3.3 ("Less than" value based on method detection limits)

Notes:

1. 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.
2. TSP is based on AP-42 factor for PM_{10}.
3. Emission factors for metals are based on factors for oil combustion in boilers.

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, 2009]. 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, 2001 and 2008] 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

The contributions of point source emissions released by combustion plants to the total emissions reported by countries to the CLRTAP emission database (WebDab) are given Table 5-1:

Table 5-1 Contributions (%) of emissions from manufacture of solid fuels to total emissions of the WebDab2005

NFR Code	Data	SO_x	NO_x	NMVOC	CO	NH_3	PM_{10}	$PM_{2.5}$	TSP
1.A.1.c — manufacture of solid fuels and other energy industries	No of countries reporting	33	33	33	32	33	32	33	32
	Lowest value	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Typical contribution	1.5	2.0	0.2	0.8	0.0	0.9	0.7	0.9
	Highest value	11.8	20.8	3.8	8.3	0.2	12.4	8.6	12.4

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.

Nitrogen oxides

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

Non-methane volatile organic compounds (NMVOC)

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

Carbon monoxide (CO)

Emissions arise from combustion activities and fugitive release of COG.

Particulate matter

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

Methane (CH_4)

Refer to IPCC guidance.

Carbon Dioxide (CO_2)

Refer to IPCC guidance.

Nitrous Oxide (N_2O)

Refer to IPCC guidance.

5.3 Controls

Details- of relevant abatement technologies are described in the BREF note for iron and steel production (http://eippcb.jrc.es/pages/FActivities.htm). 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 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.

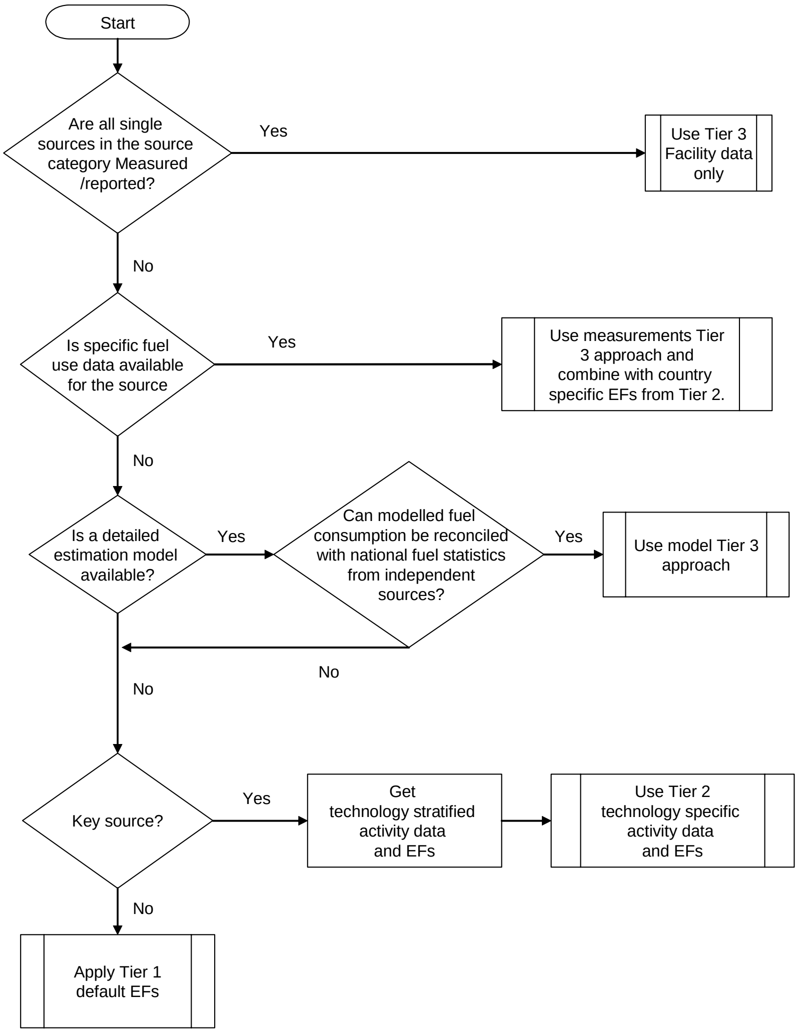

Figure 5-1 **Decision tree for combustion in manufacture of solid fuels**

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 5-2 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. Fugitive emissions are not included. 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 5-2 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 estimated	HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	22	g/GJ	8.7	42	US EPA 2008, chapter 12.2
CO	525	g/GJ	310	740	US EPA 2008, chapter 12.2
NMVOC	2.4	g/GJ	0.9	4.6	US EPA 2008, chapter 12.2
SO_x	55	g/GJ	6	160	US EPA 2008, chapter 12.2
NH_3	1.3	g/GJ	0.8	1.9	US EPA 2008, chapter 12.2
TSP	81	g/GJ	23	200	US EPA 2008, chapter 12.2
PM_{10}	49	g/GJ	10	120	US EPA 2008, chapter 12.2
$PM_{2.5}$	38	g/GJ	8	82	US EPA 2008, chapter 12.2
Pb	28.2	mg/GJ	0.34	78	US EPA 2008, chapter 12.2
Cd	1.56	mg/GJ	0.1	4.4	US EPA 2008, chapter 12.2
Hg	29.3	mg/GJ	0.1	82	US EPA 2008, chapter 12.2
As	11.24	mg/GJ	0.22	31	US EPA 2008, chapter 12.2
Cr	5.72	mg/GJ	0.21	16	US EPA 2008, chapter 12.2
Cu	24.4	mg/GJ	0.19	68	US EPA 2008, chapter 12.2
Ni	5.42	mg/GJ	0.23	15	US EPA 2008, chapter 12.2
Se	2.87	mg/GJ	0.11	7.9	US EPA 2008, chapter 12.2
Zn	46.1	mg/GJ	0.86	130	US EPA 2008, chapter 12.2
PCDD/F	8.9	ng I-TEQ/GJ	4.5	13	UNEP 2005
Benzo(a)pyrene	0.64	mg/GJ	0.37	1.1	US EPA 2008, chapter 12.2
Benzo(b)fluoranthene	0.31	mg/GJ	0.12	0.82	US EPA 2008, chapter 12.2
Benzo(k)fluoranthene	0.26	mg/GJ	0.11	0.64	US EPA 2008, chapter 12.2
Indeno(1,2,3-cd)pyrene	0.18	mg/GJ	0.07	0.46	US EPA 2008, chapter 12.2

Note:

Energy content represents net energy input of coal consumed by the coke oven.

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/te coke produced by applying a conversion of 1 285 kg coal/te coke (from the Iron and Steel BREF range of 1220–1 350 kg coal/te coke).

The factors represent combustion and process emissions from coke batteries; fugitive emissions are not included.

Table 5-3 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 conditi	NA				
Abatement technologies	NA				
Not estimated	HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO_x	880	g/Mg Coal	530	1200	US EPA 2008, chapter 12.2
CO	15000	g/Mg Coal	9200	22000	US EPA 2008, chapter 12.2
NMVOC	96	g/Mg Coal	58	135	US EPA 2008, chapter 12.2
SO_x	515	g/Mg Coal	174	1520	US EPA 2008, chapter 12.2
NH_3	39	g/Mg Coal	23	54	US EPA 2008, chapter 12.2
TSP	1810	g/Mg Coal	655	5000	US EPA 2008, chapter 12.2
PM_{10}	905	g/Mg Coal	301	2718	US EPA 2008, chapter 12.2
$PM_{2.5}$	653	g/Mg Coal	242	1763	US EPA 2008, chapter 12.2
Pb	17.1	mg/Mg Coal	9.9	30	US EPA 2008, chapter 12.2
Cd	0.18	mg/Mg Coal	0.11	0.26	US EPA 2008, chapter 12.2
Hg	0.17	mg/Mg Coal	0.1	0.24	US EPA 2008, chapter 12.2
As	11	mg/Mg Coal	6.3	19	US EPA 2008, chapter 12.2
Cr	7.5	mg/Mg Coal	6.1	9.3	US EPA 2008, chapter 12.2
Cu	7.4	mg/Mg Coal	5.5	9.9	US EPA 2008, chapter 12.2
Ni	12	mg/Mg Coal	6.5	21	US EPA 2008, chapter 12.2
Se	3.7	mg/Mg Coal	3.1	4.5	US EPA 2008, chapter 12.2
Zn	38	mg/Mg Coal	25	59	US EPA 2008, chapter 12.2
PCDD/F	230	ng I-TEQ/Mg Coal	115	250	UNEP 2005
Benzo(a)pyrene	19	mg/Mg Coal	11	32	US EPA 2008, chapter 12.2
Benzo(b)fluoranthene	8.9	mg/Mg Coal	3.4	24	US EPA 2008, chapter 12.2
Benzo(k)fluoranthene	7.6	mg/Mg Coal	3.1	19	US EPA 2008, chapter 12.2
Indeno(1,2,3-cd)pyrene	5.1	mg/Mg Coal	1.9	13	US EPA 2008, chapter 12.2

Table 5-4 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 conditi	NA				
Abatement technologies	NA				
Not estimated	HCB				
Not applicable	Aldrin, Chlordane, Chlordecone, Dieldrin, Endrin, Heptachlor, Heptabromo-biphenyl, Mirex, Toxaphene, HCH, DDT, PCB, PCP, SCCP				
Pollutant	**Value**	**Unit**	**95% confidence interval**		**Reference**
			Lower	**Upper**	
NO$_x$	420	g/Mg Coal	250	590	US EPA 2008, chapter 12.2
CO	15000	g/Mg Coal	9000	21100	US EPA 2008, chapter 12.2
NMVOC	41	g/Mg Coal	25	58	US EPA 2008, chapter 12.2
SO$_x$	2700	g/Mg Coal	1500	4800	US EPA 2008, chapter 12.2
NH$_3$	39	g/Mg Coal	23	54	US EPA 2008, chapter 12.2
TSP	2900	g/Mg Coal	1500	5600	US EPA 2008, chapter 12.2
PM$_{10}$	1900	g/Mg Coal	1100	3300	US EPA 2008, chapter 12.2
PM$_{2.5}$	1600	g/Mg Coal	1000	2400	US EPA 2008, chapter 12.2
Pb	1600	mg/Mg Coal	970	2300	US EPA 2008, chapter 12.2
Cd	90	mg/Mg Coal	54.1	126	US EPA 2008, chapter 12.2
Hg	1700	mg/Mg Coal	1020	2400	US EPA 2008, chapter 12.2
As	640	mg/Mg Coal	390	900	US EPA 2008, chapter 12.2
Cr	320	mg/Mg Coal	190	450	US EPA 2008, chapter 12.2
Cu	1400	mg/Mg Coal	840	2000	US EPA 2008, chapter 12.2
Ni	300	mg/Mg Coal	180	420	US EPA 2008, chapter 12.2
Se	160	mg/Mg Coal	98	230	US EPA 2008, chapter 12.2
Zn	2600	mg/Mg Coal	1600	3700	US EPA 2008, chapter 12.2
PCDD/F	230	ng I-TEQ/Mg Coal	115	250	UNEP 2005
Benzo(a)pyrene	19	mg/Mg Coal	11	32	US EPA 2008, chapter 12.2
Benzo(b)fluoranthene	8.9	mg/Mg Coal	3.3	24	US EPA 2008, chapter 12.2
Benzo(k)fluoranthene	7.6	mg/Mg Coal	3.1	19	US EPA 2008, chapter 12.2
Indeno(1,2,3-cd)pyrene	5.1	mg/Mg Coal	2.0	13	US EPA 2008, chapter 12.2

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:

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

- 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.

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, $g.GJ^{-1}$ (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
	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

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
	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:

1. 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.
2. New and existing plants are as defined in IPPC.

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 (0ºC, 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	SO_2	daily	3	60	850	17	241
Refinery		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.

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

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, $g.GJ^{-1}$**	**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 Large Combustion Plant 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].

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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.

Term	Definition
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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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.

Appendix A Summary of combustion plant and NFR codes

Table A1: Combustion plant and sector codes

NFR CODE	SNAP97 Codes	NOSE CODE	**Combustion plants as point and area sources**								
			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	not relevant								x
1.A.1.a	01 02 05	101.05									x
1.A.1.b	01 03 05	101.05									x
1.A.1.c	01 04 05	101.05									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

NFR CODE	SNAP97 Codes	NOSE CODE	Combustion plants as point and area sources								
			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.2.a-f	03 01 05	101.05									x

Note:

x = indicates relevant combination.

Appendix 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:

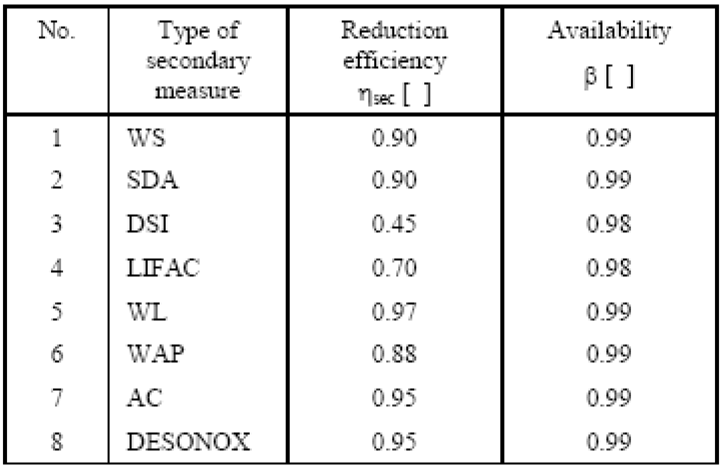
- dry controls (e.g. over-stoichiometric combustion in a dry low NOx burner; and
- wet controls (injection of water and/or steam) in order to regulate the combustion temperature.

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

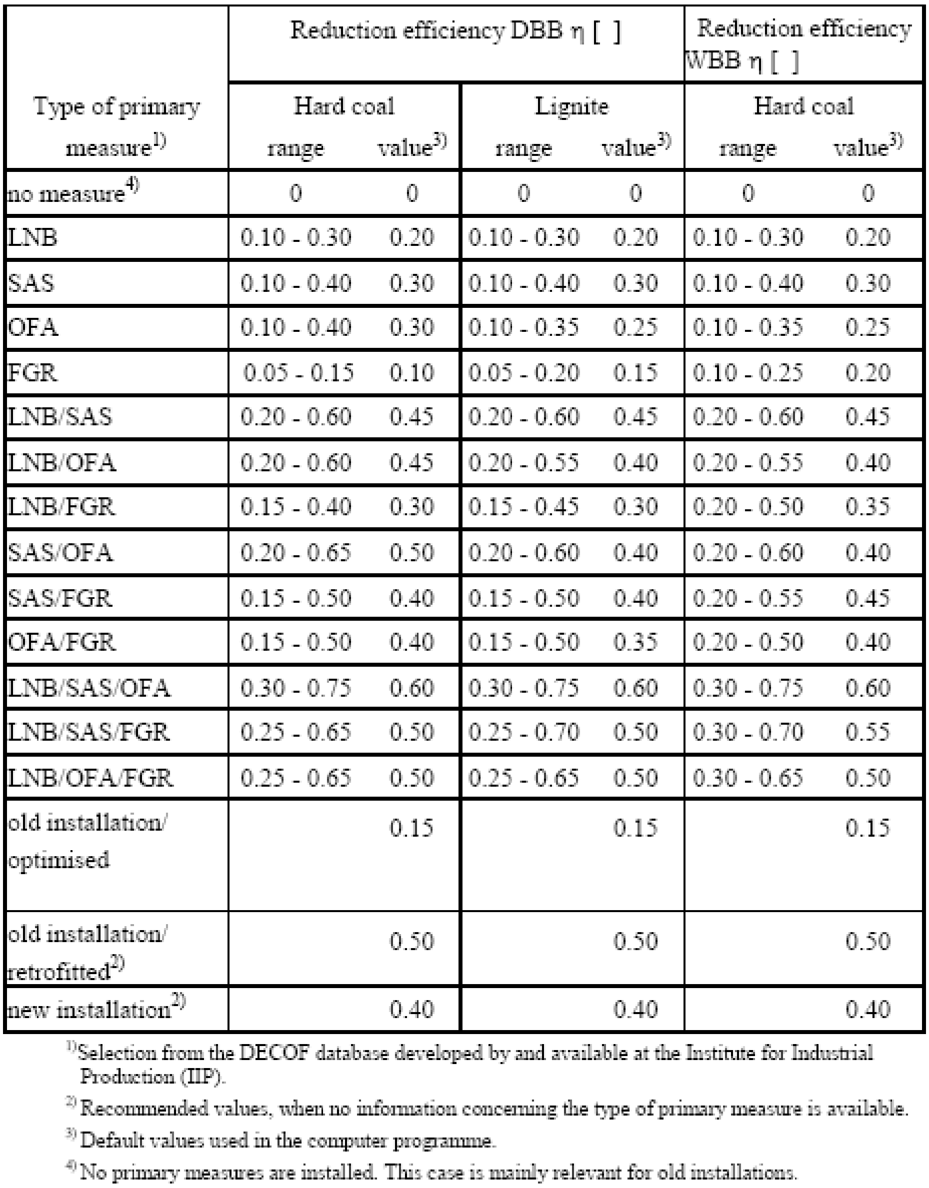


No.	Type of secondary measure	Reduction efficiency η_{sec} [ ]	Availability β [ ]
1	WS	0.90	0.99
2	SDA	0.90	0.99
3	DSI	0.45	0.98
4	LIFAC	0.70	0.98
5	WL	0.97	0.99
6	WAP	0.88	0.99
7	AC	0.95	0.99
8	DESONOX	0.95	0.99

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	0.45	0.20 - 0.60	0.45
LNB/OFA	0.20 - 0.60	0.45	0.20 - 0.55	0.40	0.20 - 0.55	0.40
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

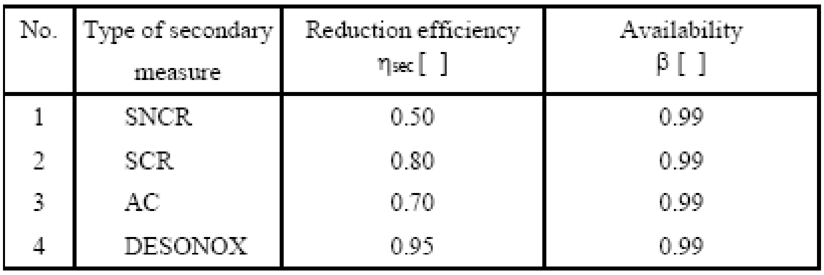
[1)] Selection from the DECOF database developed by and available at the Institute for Industrial Production (IIP).

[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_{sec} [ ]	Availability 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

Appendix C Sulphur content in fuels

Fuel sulphur contents from previous Guidebook (Chapter B111).

Table C-1 Sulphur content in fuels

Type of fuel				NAPFUE	Sulphur content of fuel		
				code	value 1)	range	unit
s	coal	hc	coking	101		0.4 - 6.2	wt.-% (maf)
s	coal	hc	steam	102		0.4 - 6.2	wt.-% (maf)
s	coal	hc	sub-bituminous	103		0.4 - 6.2	wt.-% (maf)
s	coal	bc	brown coal/lignite	105		0.4 - 6.2	wt.-% (maf)
s	coal	bc	briquettes	106		0.25 - 0.45 10)	wt.-% (maf)
s	coke	hc	coke oven	107		< 1 3)	wt.-% (maf)
s	coke	bc	coke oven	108		0.5 - 1 3) 4)	wt.-% (maf)
s	coke		petroleum	110			
s	biomass		wood	111		< 0.03 3)	wt.-% (maf)
s	biomass		charcoal	112		< 0.03 3)	wt.-% (maf)
s	biomass		peat	113			
s	waste		municipal	114			
s	waste		industrial	115			
s	waste		wood	116			
s	waste		agricultural	117			
l	oil		residual	203		0.3 5) - 3.5 6)	wt.-%
l	oil		gas	204	0.3 8)	0.08 - 1.0	wt.-%
l	oil		diesel	205	0.3 8)		wt.-%
l	kerosene			206			
l	gasoline		motor	208		< 0.05 9)	wt.-%
l	naphtha			210			
l	black liquor			215			
g	gas 2)		natural	301	(0.0075) 7)		$g \cdot m^{-3}$
g	gas		liquified petroleum gas	303	-		
g	gas		coke oven	304	8		$g \cdot m^{-3}$
g	gas		blast furnace	305	$45 \cdot 10^{-3}$ 7)		$g \cdot m^{-3}$
g	gas		coke oven and blast furnace ga	306			
g	gas		waste	307			
g	gas		refinery	308		<= 8 7)	$g \cdot m^{-3}$
g	gas		biogas	309			
g	gas		from gas works	311			

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

Appendix 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 (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	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 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], $g.GJ^{-1}$ (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).

Appendix E Calculation of emission factors from concentrations

E.1 Emission factors for combustion activities

E.1.1 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:

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

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.

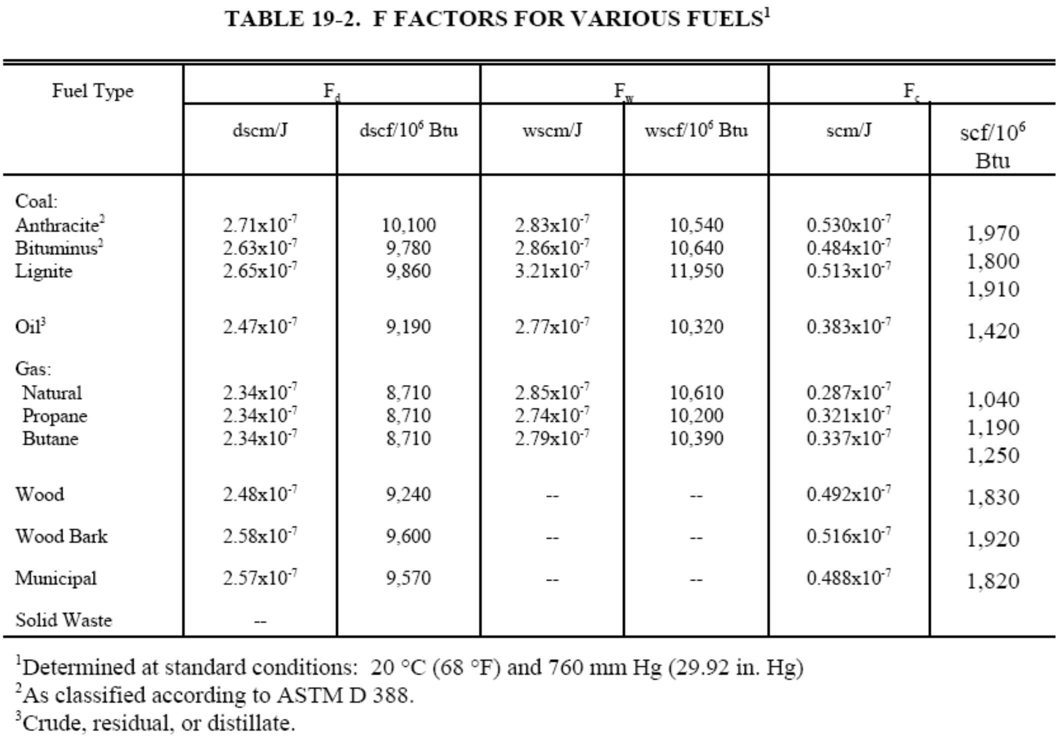


TABLE 19-2. F FACTORS FOR VARIOUS FUELS[1]

Fuel Type	F_d		F_w		F_c	
	dscm/J	dscf/10^6 Btu	wscm/J	wscf/10^6 Btu	scm/J	scf/10^6 Btu
Coal:						
Anthracite[2]	$2.71\text{x}10^{-7}$	10,100	$2.83\text{x}10^{-7}$	10,540	$0.530\text{x}10^{-7}$	1,970
Bituminus[2]	$2.63\text{x}10^{-7}$	9,780	$2.86\text{x}10^{-7}$	10,640	$0.484\text{x}10^{-7}$	1,800
Lignite	$2.65\text{x}10^{-7}$	9,860	$3.21\text{x}10^{-7}$	11,950	$0.513\text{x}10^{-7}$	1,910
Oil[3]	$2.47\text{x}10^{-7}$	9,190	$2.77\text{x}10^{-7}$	10,320	$0.383\text{x}10^{-7}$	1,420
Gas:						
Natural	$2.34\text{x}10^{-7}$	8,710	$2.85\text{x}10^{-7}$	10,610	$0.287\text{x}10^{-7}$	1,040
Propane	$2.34\text{x}10^{-7}$	8,710	$2.74\text{x}10^{-7}$	10,200	$0.321\text{x}10^{-7}$	1,190
Butane	$2.34\text{x}10^{-7}$	8,710	$2.79\text{x}10^{-7}$	10,390	$0.337\text{x}10^{-7}$	1,250
Wood	$2.48\text{x}10^{-7}$	9,240	--	--	$0.492\text{x}10^{-7}$	1,830
Wood Bark	$2.58\text{x}10^{-7}$	9,600	--	--	$0.516\text{x}10^{-7}$	1,920
Municipal	$2.57\text{x}10^{-7}$	9,570	--	--	$0.488\text{x}10^{-7}$	1,820
Solid Waste	--					

[1] Determined at standard conditions: 20 °C (68 °F) and 760 mm Hg (29.92 in. Hg)

[2] As classified according to ASTM D 388.

[3] Crude, residual, or distillate.

The Fd 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.

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

Where :

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

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

273/293 Volume correction — ratio of temperatures in Kelvin

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

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

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

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

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:

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

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.

$$EF = EF_{thermal} . CV$$

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.

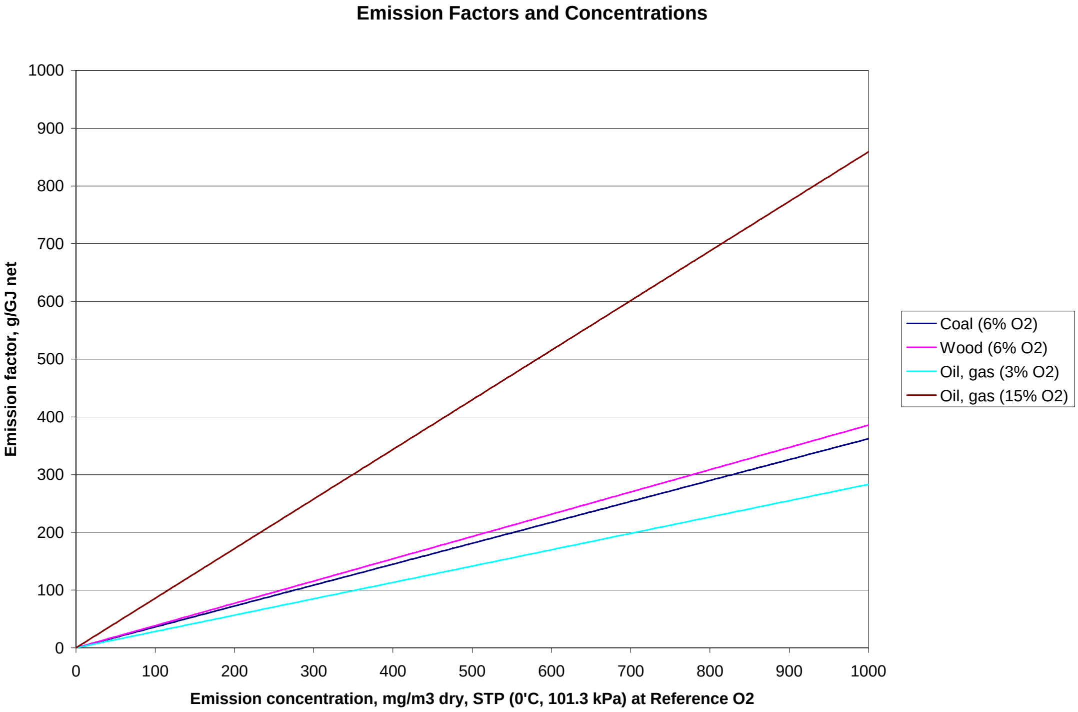


Figure E1 Emission factors — selected fuels and standardised concentrations up to 1 000 mg.m^{-3}

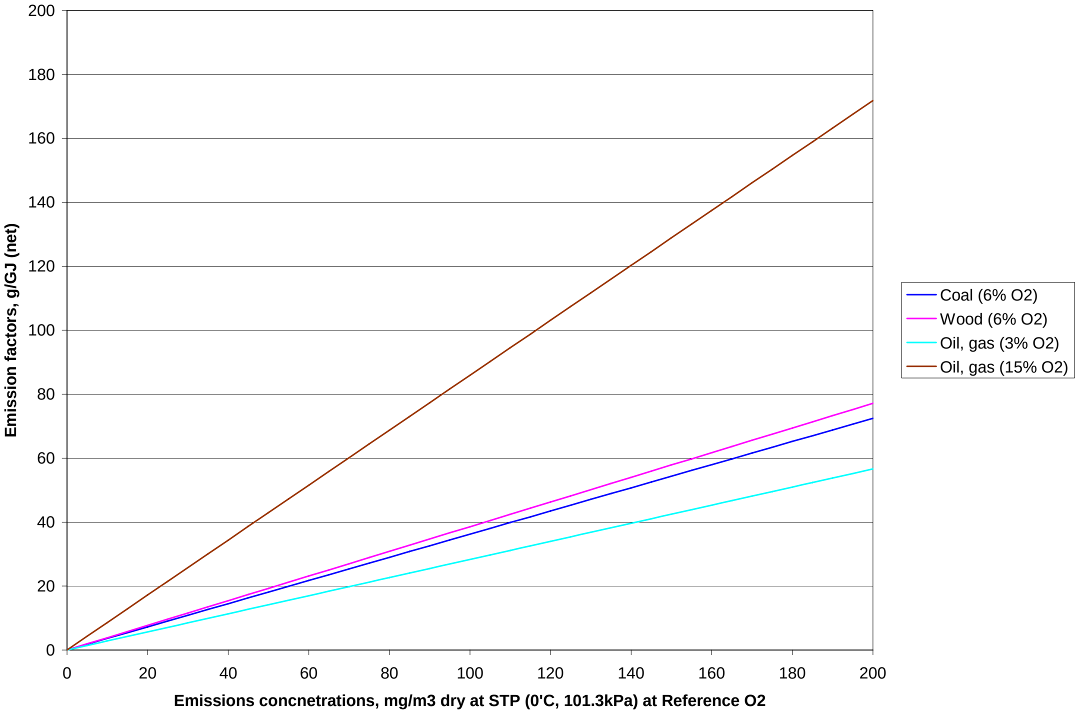


Figure E2 Emission factors — selected fuels and standardised concentrations up to 200 mg.m^{-3}

Appendix F Emission factors from older versions of the Guidebook

Chapter B111

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

Type of fuel				NAPFUE code	Thermal boiler capacity [MW]				
					>= 300[32)]			>= 50 and < 300[32)]	
					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]													no specification CORINAIR $90^{44)}$
> 50 and < $300^{32)}$			< $50^{32)}$										
Type of boiler			Type of boiler						Gas turbine		Stationary engine		
FBC		GF	DBB/$boiler^{27)}$	WBB	FBC			GF					
PFBC	CFBC				PFBC	CFBC	AFBC		SC	CC	CI	SI	
$150^{1)}$	$70^{1)}$	$150^{1)}$	$180^{1),31)}$, $230^{1),29)}$	X		$70^{1)}$		$150^{1)}$	X	X	X	X	$545^{44)}$
$150^{1)}$	$70^{1)}$	$150^{1)}$	$180^{1),31)}$, $230^{1),29)}$			$70^{1)}$		$150^{1)}$					36.5 - $761^{44)}$
$150^{1)}$	$70^{1)}$	$150^{1)}$	$180^{1),31)}$, $230^{1),29)}$			$70^{1)}$		$150^{1)}$					20.5 - $1,683^{44)}$
$150^{1)}$	$70^{1)}$	$150^{1)}$	$180^{1),31)}$, $230^{1),29)}$			$70^{1)}$		$150^{1)}$					180 - $380^{44)}$
													33.3 - $175^{44)}$
			$300^{1)}$		$300^{1)}$	$300^{1)}$							
		$200^{1)}$, 33 - 115^{1}	$200^{1)}$, 33 - $115^{15)}$					$200^{1),15)}$					50 - $200^{44)}$
$160^{1)}$	$100^{1)}$	$230^{1)}$	$280^{1)}$		$160^{1)}$	$100^{1)}$							150 - $240^{44)}$
		90 - $463^{16),17)}$						90 - $463^{16),17)}$					$220^{44)}$
		139 - $140^{18)}$						139 - $140^{18)}$					
													80 - $200^{44)}$
		$88^{6)}$											$160^{44)}$
X	X	X	$140^{1),29)}$, $180^{1),30)}$	X	X	X		X	$250^{45)}$		1,090-$1,200^{45)}$		24 - $370^{44)}$
			$80^{1)}$, $100^{1)}$						120 $^{1),35)}$, $350^{1),33)}$, $380^{1),34)}$, $780^{1),}$		100 - $1,200^{45)}$		50 - $269^{44)}$
									100 - $700^{45)}$, $300^{46)}$		$600^{1),37),42)}$, $1,200^{1),38)}$	$1,000^{1),40),42)}$, $1,800^{1),39),42)}$	
													$180^{44)}$
													20 - $440^{44)}$
X	X	X	$100^{1)}$, 48 - $333^{22),23),24)}$	X	X	X		X	150 - $360^{45)}$		$600^{1),37),42)}$, $1,200^{1),38),4}$	$1,000^{1),40),42)}$, $1,800^{1),39),}$	22 - $350^{44)}$
									$188^{4),41)}$	$187^{4),41)}$			
			88 - $333^{23),24)}$										35 - $100^{44)}$
			$90^{1),23),24)}$										70 - $571^{44)}$
			88 - $333^{23),24)}$										6.7 - $330^{44)}$
			88 - $333^{23),24)}$										
			88 - $333^{23),24)}$										35 - $327^{44)}$
			$140^{1),23),24)}$						150-$151^{45)}$				35 - $140^{44)}$
			88 - $333^{23),24)}$										$60^{44)}$

[1] CORINAIR 1992 /80/, without primary measures

[2] Ratajczak 1987 /103/, Kolar 1990 /17/

[3] Lim 1982 /91/, Kolar 1990 /17/

[4] Mobley 1985 /96/, Kolar 1990 /17/

[5] LIS 1977 /92/

[6] Radian 1990 /102/, IPCC 1994 /88/, without primary measues

[7] UBA 1985 /111/, Kolar 1990 /17/

[8] Kolar 1990 /17/

[9] Bartok 1970 /75/, Kolar 1990 /17/

[10] Kremer 1979 /90/, Kolar 1990 /17/

[11] UBA 1981 /110/, Kolar 1990 /17/

[12] LIS 1987 /93/

[13] Davids 1984 /81/, Kolar 1990 /17/

[14] Ministry 1980 /95/, Kolar 1990 /17/

[15] utility boiler: 112[6], commercial boiler: 33[6], industrial boiler: 115[6]

[16] utility boiler (GF): 140[6], commercial boiler: 463[6], commercial open burning: 3[6] kg/Mg waste

[17] GF: 90 - 180[8]

[18] industrial combustion (mass burn.): 140[6], industrial combustion (small burner): 139[6]

[19] DBB (power plants): 240[11], 245[10], 296[9], 270[10]

[20] utility boiler: 201[6], commercial boiler: 155[6], industrial boiler: 161[6]

[21] utility boiler: 68[6], commercial boiler: 64[6]

[22] utility boiler: 267[6], commercial boiler: 48[6], industrial boiler: 67[6]

[23] power plant: 160[9], 170[10], 185[10], 190[11], 215[10], 333[13]

[24] industry: 88[9], 100[11]

[25] 50 - 100 MW thermal

[26] 100 - 300 MW thermal

[27] DBB for coal combustion; boiler for other fuel combustion

[28] wall firing

[29] tangential firing

[30] wall/bottom firing

[31] wall/tangential firing

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

[33] no specification

[34] with diffusion burner

[35] modern with pre-mixer

[36] derived from aero engines

[37] prechamber injection

[38] direct injection

[39] 4 stroke engines

[40] 2 stroke engines

[41] 80[1,35], 250[1,33], 160 - 480[1,34], 650[1,36]

[42] 1000[1,33]

[43] The formation of thermal-NO is much more influenced by the combustion temperature than by the burner arrangement within the boiler /64/. Therefore, no emission factors are given for different burner arrangements (e.g. tangential firing).

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

[45] CORINAIR90 data of combustion plants as point sources

[46] AP42 /115/

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
						$\eta = 0$	$\eta = 0.20$	$\eta = 0.45$	$\eta = 0.45$	$\eta = 0.60$	$\eta = 0$	$\eta = 0.20$	$\eta = 0.45$	$\eta = 0.40$	$\eta = 0.60$
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
						$\eta = 0$	$\eta = 0.20$	$\eta = 0.45$	$\eta = 0.40$	$\eta = 0.60$					
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	Thermal boiler capacity [MW]					no specification
					>= 50		< 50			
				code	boiler	GF	boiler	Gas turbine	Stationary engine	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 combustion									
					Utility combustion			Commercial comb.		Industrial combustion				
			Type of fuel	NAPFUE code	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 8.2a Emission factors for combustion processes burning hard coal

Fuel	**NAPFUE**	**NFR Codes**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
Hard coal					**TSP**	**PM_{10}**	**$PM_{2.5}$**	
Bit. coal	101	Various	Electricity, CHP, heat	FF < 20 mg.Nm^{-3}	6	6	5	CEPMEIP ‘BAT’
				ESP (or FF) < 50 mg.Nm^{-3}	15	12	6	Scaled from CEPMEIP ESP factor. TSP scaled to a nominal 100 mg.Nm^{-3} limit
				ESP < 100 mg.Nm^{-3}	30	25	12	From CEPMEIP sub-bit coal ‘high efficiency ESP’, TSP scaled to a nominal 100 mg.Nm^{-3} limit
				ESP Old/conventional < 500 mg.Nm^{-3}	140	70	17	CEPMEIP
				Unit with multicyclone	100	60	35	CEPMEIP
				Unit, uncontrolled or cyclone	500	250	100	CEPMEIP (N.B. such a high emission concentration would apply to few if any plant)
Sub-bituminous coal	103	Various	Electricity, CHP, heat plant	FF < 20 mg.Nm^{-3}	6	6	5	CEPMEIP ‘BAT’
				ESP (or FF) < 50 mg.Nm^{-3}	15	12	6	Scaled from CEPMEIP ESP factor (TSP scaled to a nominal 100 mg.Nm^{-3} limit)
				ESP	30	25	12	From CEPMEIP sub-bit coal

Fuel	NAPFUE	NFR Codes	Activity description	Activity detail	Emission factor			Notes
				< 100 $mg.Nm^{-3}$				‘high efficiency ESP’, TSP scaled to a nominal 100 $mg.Nm^{-3}$ limit
				ESP Old/conventional < 500 $mg.Nm^{-3}$	140	70	17	CEPMEIP
				Unit with multicyclone	100	60	35	CEPMEIP
				Unit, uncontrolled or cyclone	500	250	100	CEPMEIP (the lower of the two TSP factors, the 800 g GJ-1 for small uncontrolled plant is such a high emission concentration that would apply to few if any plant)
Coke	107	1.A.1.b	Oil refineries	Uncontrolled	500	250	100	Coke is unlikely to be burned as primary fuel, when co-fired use the factor for the principal fuel

Table 8.2b 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 8.2c 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

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
								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 8.2d 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 8.2e 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 8.2f 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 8.2g 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

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
					TSP	PM_{10}	$PM_{2.5}$	
								750 mg.N Nm^{-3})

Table 8.2h 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)

Chapter B111(S2)PMv2

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	

---

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

Fuel	**Technology**	**Emission factor, g GJ^{-1}**			**Notes** ([4])
		TSP	**PM_{10}**	**$PM_{2.5}$**	
Heavy fuel oil (3 % S)	No control	64	45	33	Assumes 3 % sulphur (maximum permitted in EU countries)
	FGD	3.8	3.8	3.7	
Other liquid fuels	LPG	2.0	2.0	2.0	
Biomass	FF	51	38	33	AP-42 wood waste
	ESP	28	21	18	

Table 8.2a Emission factors for combustion processes burning hard coal

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

---

(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)
				ESP old/conventional < 500 mg.Nm^{-3}	140	70	17	CEPMEIP
				Conventional large unit with multicyclone	100	60	35	CEPMEIP
				Conventional unit, uncontrolled or cyclone	500	250	100	CEPMEIP (N.B. such a high emission concentration would apply to few, if any, plant)
Coke	107							Coke is unlikely to be burned as primary fuel, when co-fired use the factor for the principal fuel.

Table 8.2b **Emission factors for combustion processes burning brown coal**

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference/Comments
					TSP	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 8.2c 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

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference
								burning is often controlled under national/international regulation to a more stringent specification)

Table 8.2d Emission factors for combustion processes burning natural gas

Fuel (IPCC Cat)	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference
					TSP	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 8.2e 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 8.2f 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 8.2g 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 8.2h 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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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 gGJ^{-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 8.2a 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 8.2b Emission factors for compression ignition combustion processes

Fuel (IPCC Cat)	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor g GJ^{-1}			Reference/Comments
					TSP	PM_{10}	$PM_{2.5}$	
Natural gas			Dual fuel engine, gas with HFO		11	11	11	LCP BREF, assumed all PM2.5
Heavy fuel oil			Diesel engine		50	41	39	LCP BREF, 'BAT' US EPA profile applied
			Diesel engine		< 64	53	50	LCP BREF, US EPA profile applied, applicable to older equipment
Gas oil			Diesel engine	< 0.02 % S	< 26	21	20	LCP BREF, US EPA profile
			Diesel engine		< 17	14	14	Smaller unit with diesel particulate filter, US EPA profile

SO_2: rapporto stechiometrico

NO_x: report 1/09 CONCAWE – Air pollutant emission estimation methods for E-PRTR reporting by refineries

CO: EPA AP 42, fifth edition, section 1.4 ,section 1.3

PM_{10} e PTS: European Environment Agency – technical report n° 9/2009; EPA AP 42, fifth edition, section 5

Air pollutant emission estimation methods for E-PRTR reporting by refineries

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Prepared by the CONCAWE Air Quality Management Group's Special Task Force on Emission Reporting Methodologies (STF-69)

D. Withinshaw (Chairman)

E. de Vries
N. Karnavos
F. Leotoing
P. Martinez Conesa
N. Ribeiro
B. Smithers

P. Roberts (Technical Coordinator)

Brussels
January 2009

ABSTRACT

This report is the first revision of CONCAWE Report 3/07, which itself replaced Report No. 9/05R *Air Pollutant Emission Estimation Methods for EPER and PRTR Reporting by Refineries*. It provides algorithms to permit emission estimates to be made by refineries to meet the reporting requirements of the European Pollutant Release and Transfer Register (E-PRTR) regarding pollutant emissions to air.

KEYWORDS

Air pollution, refineries, E-PRTR, emission factors, sources.

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SUMMARY

With the introduction of the public domain databases of pollutant releases - EPER (European Pollutant Emission Register) and its successor E-PRTR (European Pollutant Release and Transfer Register) - there is a need for reliable and consistent emissions data in the oil industry sector.

The E-PRTR Regulation requires that annual emissions of key species are reported where those emissions exceed a minimum threshold.

This Report provides the estimation algorithms and emission factors for uncontrolled releases of air pollutants from stationary sources at oil refineries which CONCAWE recommends for E-PRTR reporting purposes, where measurements have not been undertaken. The emission estimation algorithms are fully referenced and the emission factors provided in a consistent metric unit base.

CONCAWE has previously published Report No. 9/05 (and a revised version 9/05R) *Air Pollutant Emission Estimation Methods for EPER and PRTR Reporting by Refineries.*

Report No. 9/05R was submitted to the European Commission and the European Environment Agency and is referenced as a source of sector specific calculation methods in the EU (2006) *Guidance Document for the Implementation of the European PRTR.*

It was updated in 2007 by Report No. 3/07 *Air Pollutant Emission Estimation Methods E-PRTR Reporting by Refineries.* This provided new and revised factors and algorithms and focused on the reporting requirements of the E-PRTR Regulations.

This current report updates Report No. 3/07 and contains some additional algorithms and new and updated emission factors. A change log is presented in Appendix 2.

It is expected that future refinements to the emission factor database will be made. This document is therefore a "snapshot" of the present knowledge. Before using this report, the version number should be compared with the control copy which is posted as an electronic document on the CONCAWE web-site (www.concawe.org).

1. INTRODUCTION

The European Directive 96/61/EC on integrated pollution prevention and control (IPPC) [1] mandated the publication of a regularly updated pollutant inventory. The European Pollutant Emission Register (EPER) required the reporting of a number of pollutants, both to air and water, from all facilities listed in Annex 1 of the IPPC Directive.

The EPER requirements have been succeeded by those of the European Pollutant Release and Transfer Register (E-PRTR) Regulation [2]. This implements at EU level the UNECE PRTR Protocol which was signed in 2003 in Kiev [3]. The first report of the E-PRTR will be for the year 2007 and reporting will be annually thereafter. The E-PRTR is more extensive than EPER in a number of respects. For example, the list of pollutants is enlarged and the amount of information required to be reported concerning emissions and transfers of pollutants has increased. Guidance on the implementation of the E-PRTR has been provided by the European Commission [4]. The list of air pollutants and their threshold values above which emissions must be reported are given in **Appendix 1**.

With regard to the data submissions for these Registers, CONCAWE identified three issues that require attention by the oil refining sector:

1. The data submitted should be reliable, in the sense that they represent as accurately as possible the actual pollutant emissions. Over-estimation of emissions is clearly to be avoided. Moreover, under-estimation can give a false impression of what pollution emissions levels can be reached under realistic circumstances.
2. Data should be consistent between comparable sources within the industry.
3. The sharing of best practices in terms of emission factors is important in order to improve the quality of the reporting.

To address these issues the CONCAWE Air Quality Management Group initiated a review of the published emission factors for those air pollutants which may be emitted in excess of the reporting threshold values from stationary sources found at the majority of European refineries.

It was noted that there were no emission estimation guidelines for each and every one of the pollutants to air from refineries which may possibly require reporting under the regulations. Although guidance is provided in the European Environment Agency Emission Inventory Guidebook [5] for the major air pollutants, estimation methodologies are not available for all of the E-PRTR listed pollutants.

On the other hand, for some pollutants such as non-methane volatile organic compounds (NMVOCs) there are a number of different estimation methodologies being used by European refineries e.g. protocols produced by the US EPA [6] and a number of nationally agreed methods such as that published by the UK Energy Institute [7].

CONCAWE, therefore, published Report No. 9/05 and its first revision No. 9/05R [8] which comprised a compendium of emission factors, with associated references, for the uncontrolled release of air pollutants. The compendium could not be fully comprehensive as emission factors are not available in the public domain for all sources and/or pollutants. CONCAWE, however, considered this to be the most appropriate set of emissions factors for the refining sector.

Report No. 9/05R was replaced by Report No. 3/07 [9], which focused on the requirements of the E-PRTR and contained additional algorithms and updated emission factors.

This current report is the first revision of Report No. 3/07. It provides the estimation algorithms which CONCAWE recommends for E-PRTR reporting purposes where measurements have not been undertaken.

The report does not consider the estimation of accidental or non-routine (e.g. due to maintenance) releases to air. Guidance in reference [4] recommends that emissions from such releases should be estimated by sites on an ad-hoc basis using whatever data are available and the most appropriate methods considered for the circumstances. Nor does it provide guidance on estimating emissions from mobile sources.

The emission factors provided are for uncontrolled releases. Reported emissions must take account of any abatement equipment installed e.g. wet gas scrubbers, electrostatic precipitators, etc.

Where emission factors are available, algorithms are provided for sources found in the majority of European refineries. There are some emission sources for which estimation algorithms are not provided in this report e.g. coke calciners. Refineries should review all of the sources of air pollutants on-site and establish if there are any additional sources from those listed in this report which may require emission estimates to be made for E-PRTR reports.

CONCAWE has previously published reports on non-methane volatile organic compound (NMVOC) emissions from refineries and other downstream oil industry sources. However Report No. 85/54 [10] which was widely used by Industry is now out of date and is no longer available. Although marketing terminals and service stations are not subject to E-PRTR reporting requirements, for completeness this current report provides NMVOC emission estimation algorithms which are applicable to gasoline storage and handling at these facilities.

A summary of the changes to the algorithms and emission factors given in Report No. 3/07 is provided in **Appendix 2**.

2. EMISSION ESTIMATION METHODOLOGIES

There are a number of sources of emission estimation methodologies:

- Oil industry associations e.g. CONCAWE, API, etc.
- Oil companies that have published methods in the professional press
- National and international environmental authorities e.g. US EPA, European Environment Agency, etc.
- International organisations e.g. IPCC, etc.
- European Commission.

Methodologies published by the national and international organisations may be non oil-industry sector specific.

Only those estimation methods which are currently in the public domain were considered for inclusion in this report. The methodologies were considered in the following order of preference to determine those most representative for oil industry sources:

- Methods published by the oil industry
- Sector specific methods published by national and international authorities
- Non-sector specific methods.

Reported E-PRTR emission data must include a code to identify the type of estimation methodology used. The classification codes are simple letters:

> Class M: emission data are based on measurements. Additional calculations are needed to convert the results of measurements into annual emission data. Emissions can be derived from continuous or discontinuous measurements of pollutant concentrations. Alternatively, they can be determined based on the results of short term or spot measurements.
>
> Class C: emission data are based on calculations using activity data (e.g. fuel used, production rate) and emission factors or mass balances.
>
> Class E: emission data are based on non-standardised estimations derived from best assumptions or expert guesses that are not based on publicly available references or good practice guidelines.

Where data are measured or calculated, the method of measurement and/or the calculation method must also be provided in the E-PRTR data submission.

The EU Guidance document [4] provides a list of the internationally approved or “equivalent” methodologies that should be used and the method names to be included in the E-PRTR submission. One of the accepted equivalent methodologies is a “European-wide sector specific calculation method, developed by industry experts, which has been delivered to the European Commission, to the European Environment Agency and the relevant international organisations”. The EU Guidance document [4] references CONCAWE Report No. 9/05R [8] which has been submitted to the EC and EEA. This current report is a replacement for Report No. 9/05R and hence use of the algorithms in this report can be considered to be an approved calculation methodology: data could then be reported using the letters “C” and method name acronym “SSC” (sector specific calculation).

3. POLLUTANTS

There are sixty air pollutants which must be reported under the E-PRTR requirements if their respective annual emission threshold values are exceeded at a facility. All of these are shown in **Appendix 1,** with their threshold values.

The EU Guidance Document on E-PRTR Implementation [4] provides indicative lists of the pollutants likely to be emitted on a sector specific “activity” basis. In addition to having its own specific sectoral activity of “mineral oil and gas refineries”, the Oil Industry also uses combustion units with ratings in excess of 50 MW. These are included in the sectoral activity classified within the PRTR Regulation [2] as “thermal power stations and other combustion installations”.

Those pollutants on the sector specific indicative lists within the EU Guidance Document for these two activities are listed in **Appendix 1**.

Information was requested from the CONCAWE member companies in 2002 concerning the emissions of air pollutants from refineries reported either internally or externally. **Appendix 1** lists those pollutants which had been estimated, by at least one of the nine companies who responded, to exceed the E-PRTR reporting thresholds.

Appendix 1 indicates that the pollutants included on the two EU indicative lists are almost identical to those on the oil industry list. The difference is the addition of two pollutants on the combustion installation list: dioxins/furans and trichloroethylene.

Trichloroethylene (TRI) is not a product of combustion; its major use is as an organic solvent for industrial degreasing. The inclusion of this pollutant on the sector specific indicative list for combustion installations appears to be due to an anomaly in the EPER database. Only one facility classified as "Combustion installation > 50 MW" reported emissions of TRI, but these would appear to be from the process of manufacturing rubber tyres and tubing at the site and not as a by-product of combustion. This report, therefore, does not consider this pollutant further.

This report provides algorithms to estimate the emissions of all of the other pollutants on the indicative lists in the EU Guidance for refineries and combustion installations rated in excess of 50 MW.

Anthracene and naphthalene are two pollutants that are known to be emitted by refineries, but are not on the sector specific indicative lists. A review of the emissions of these pollutants is provided in **Appendix 3.** It is shown that, even for the largest refineries, neither anthracene nor naphthalene emissions are likely to exceed their E-PRTR reporting threshold values.

Sites should review their processes and emission sources to establish if there is the potential for any of the other E-PRTR air pollutants to be released in excess of their reporting thresholds.

4. EMISSION SOURCES

4.1. REFINERIES

This report divides the sources found within the majority of refineries, for which emission factors are available in the public domain, into the following categories:

- Combustion
- Process vents
- Storage
- Loading
- Miscellaneous

Combustion sources considered comprise:

- Boilers
- Furnaces
- Fired waste heat boilers
- CO boilers
- Gas turbines
- Gas engines
- Diesel engines
- Incinerators
- Flares

Process sources included are:

- Hydrogen plants
- Fluid coking units
- Fluidised catalytic cracking units
- Catalytic reforming units

Miscellaneous sources included are:

- Process drains
- Oil-water separators
- Fugitive emissions from pressurised pipe work and components
- Refrigeration systems
- Use of SF_6

There are some sources which are only found in a limited number of refineries for which algorithms are not given in this report. One example for which emission factors are available [11] is coke calcining.

4.2. GASOLINE MARKETING FACILITIES

Neither marketing distribution terminals nor service stations are regulated under the terms of the IPPC Directive [1] and hence are not required to submit E-PRTR reports.

Emission estimates for distribution terminals and service stations may, however, be made by oil companies for their own environmental reporting purposes.

Emissions from distribution terminals are primarily NMVOCs due to the storage and loading of refined products, in particular gasolines. Emission estimation methods for sources of NMVOCs at terminals are provided in **Appendix 4.1**.

Some terminals have small steam raising boilers e.g. to heat heavy oil storage tanks. The algorithms provided in this report can be used to estimate combustion emissions from these facilities.

Unlike refineries and terminals, storage at service stations is in underground horizontal tanks. Emissions occur from these due to the displacement of vapours during filling and the evaporation of the stored gasoline. Emissions also occur due to the filling of automobile fuel tanks and from minor drips and spills during those operations. Estimation methods for NMVOC emissions from these sources are provided in **Appendix 4.2**.

5. EMISSION ESTIMATION ALGORITHMS

5.1. INTRODUCTION

Algorithms are provided for the E-PRTR air pollutants which may exceed their emissions reporting thresholds. The level of emissions depends upon the refinery crude throughput, the process units installed, fuels consumed, type of equipment in use, procedures in place, etc.

Algorithms are given on a pollutant by pollutant basis in **Sections 7** to **30**, in the order of the pollutant list in **Appendix 1**.

Algorithms are also provided in **Appendix 3** for two additional pollutants (anthracene and naphthalene). It is demonstrated that the emissions of neither of these pollutants are likely to exceed their E-PRTR reporting thresholds.

Estimation algorithms are given for the sources of each pollutant. A reference is provided for each method, with additional details where considered appropriate.

If no pollutant algorithm is provided for a source, it is because:

- emissions of the pollutant do not occur from that source;
- emissions are considered negligible; or
- no published algorithm has been found or considered appropriate for sources at refineries.

Table 1 indicates those sources for which pollutant algorithms are provided in this report.

Emission factors are given in scientific units to 3 significant figures i.e. 5.67E+03 is equivalent to 5670.

It should be noted that data submitted in E-PRTR reports should be expressed in kg/year and with three significant digits, e.g. 123 000, 17.9, 2.10.

Table 1 Sources for which pollutant emission estimation methodologies are provided in this report

	CH_4	CO	CO_2	HFC	N_2O	NH_3	NMVOC	NO_X	SF_6	SO_X	HCFC	As	Cd	Cr	Cu	Hg	Ni	Pb	Zn	Dioxins	C_6H_6	PAH	Cl	PM_{10}
Boiler	×	×	×		×		×	×		×		×	×	×	×	×	×	×	×	×	×	×		×
Furnace	×	×	×		×		×	×		×		×	×	×	×	×	×	×	×	×	×	×		×
Gas turbine	×	×	×		×		×	×		×		×	×	×	×	×	×	×	×		×	×		×
Gas engine	×	×	×		×		×	×		×											×	×		×
Diesel engine	×	×	×		×		×	×		×											×	×		×
Pilot or support fuel	×	×	×		×		×	×		×		×	×	×	×	×	×	×	×		×	×		×
Incinerator	×	×	×		×		×	×		×		×	×	×	×	×	×	×	×		×	×		×
Flare	×	×	×				×	×		×											×			×
Hydrogen plant			×				×																	
Fluid coking unit			×				×					×			×	×	×	×	×		×			×
Catalytic cracking unit		×	×			×	×	×		×		×	×		×	×	×	×	×		×	×		×
Catalytic reforming unit		×	×							×										×			×	
Process drainage							×																	
Oil-water separator							×																	
Process fugitives	×						×														×			
Loading							×																	
Storage							×																	
SCR/SNCR						×																		
Refrigeration				×		×					×													
Lab/test/HV switch gear									×															

5.2. EMISSION FACTORS DERIVED FROM MEASUREMENTS WITH DATA BELOW THE LIMIT OF DETECTION

A few emission factors were originally derived from measurements where, if the values measured were all below the limit of detection, those data points were set at the limit of detection level. Where possible, in this report these factors have been identified and the following rule used to adjust them:

- Where all data points were below the measurement detection limit, the emissions factor has been set to zero (i.e. it is considered that the source is not proven).

Where both the averages of data points above and below the limit of detection (the ‘detect’ and ‘non-detect’ values) are provided in a reference, along with the number of data points used to derive these, a weighted value as calculated below has been used in this report.

- Weighted factor = [(average detect value × number of detect samples) + (average non-detect value × number of non-detect samples × detect ratio)] / total number of samples

where detect ratio = number of detect samples / total number of samples.

Reference: [12], Section 7.4.7

Where only the average of the detect and non-detect values and the detect ratio is provided in a reference, a weighted value as calculated below has been used in this report.

- Weighted factor = [(average value × detect ratio) + {(average value / 2) × (1 - detect ratio)}]

All algorithms where these adjustments have been made are identified in the text.

5.3. TREATMENT OF DATA WHERE MEAN AND MEDIAN VALUES AVAILABLE

In references [11], [13] and [14], both the mean and median values of pollutant emission data sets are provided. A small number of the data sets used to determine emission factors are highly skewed, resulting in mean values dominated by a few very high values that are not representative of the majority of readings. Where the mean value exceeds the median value by more than a factor of ten, the median has been considered a more realistic value and has been used in this report. In all other cases the mean value has been used.

All algorithms where the median value has been used are identified in the text.

5.4. OVERVIEW OF COMBUSTION ALGORITHMS

For many of the pollutants arising from combustion sources the published emission factors are one of the following types:

a) Mass per unit volume combusted (EF_{VOL})
b) Mass per energy consumed (EF_{NCV})

To provide a consistent approach within this report, algorithms using emissions factors based on EF_{NCV} are provided. This type of factor enables emissions to be calculated for fuels which are widely different in composition to those for which EF_{VOL} was originally determined. Where published factors are only in the form of EF_{VOL}, the values of EF_{NCV} have been calculated using default values for the fuels. Where appropriate, this is noted within the text. Details, along with the default fuel heating values used in this report, are provided in **Appendix 5**.

5.4.1. Heating Values

In the USA, the norm is to use Higher Heating Value (HHV) (or Gross Calorific Value) for a fuel, whilst in Europe the Net Calorific Value (NCV) (or Lower Heating Value - LHV) is usually quoted. In this report all heating values quoted are NCVs and all emission factors involving heat energy require the use of the corresponding fuel NCV, unless otherwise quoted.

NCV = HHV x Correction Factor for heat of vaporisation of water in the fuel

For liquid fuels:

$$NCV = HHV \times 0.95$$

For gaseous fuels:

$$NCV = HHV \times 0.9$$

Reference: [15], Section 3.6.3

6. EMISSION CONTROLS

6.1. OVERVIEW

The algorithms provided in this report (with the exceptions identified in **Sections 6.2** and **6.3**) assume that no emission reduction control equipment (e.g. flue gas desulphurisation system, vapour recovery unit, etc.) is installed in vent lines, stacks or flues.

Calculated emissions must, therefore, take account of any emission controls. The algorithm to be used is:

Emissions reported = Uncontrolled emissions × (1 – [EFF x ONTIME] / 10 000)

where:
EFF = Average percentage efficiency of emission reduction control equipment over reporting period.
ONTIME = Percentage of the time that the emission reduction equipment is operational when required during the reporting period.

Where there are two or more emission control devices in series impacting a particular pollutant (e.g. for particulates: cyclone plus electrostatic precipitator) then the effect of each device on the pollutant emissions must be taken into account. For example, if two devices are installed, with respective efficiencies of EFF_1 and EFF_2 and operating times of $ONTIME_1$ and $ONTIME_2$, then the algorithm is:

$$\text{Emissions reported} = \text{Uncontrolled emissions} \times \{(1 - [EFF_1 \times ONTIME_1] / 10\,000) \times (1 - [EFF_2 \times ONTIME_2] / 10\,000)\}$$

For vapour recovery units (VRUs) designed to reduce NMVOC emissions from loading operations, algorithms are also provided where the average vent emission concentration is known but not the overall VRU efficiency.

6.2. PARTICULATE EMISSIONS FROM CATALYTIC CRACKING UNITS

The algorithms for particulate (PM_{10}) and metals emissions from these units assume that there are cyclone systems installed inside the regenerator vessel to separate the catalyst particles from the hydrocarbon vapours. If additional cyclones or other emission abatement devices such as electrostatic precipitators are installed external to the regenerator then the effect of these additional controls to reduce emissions must be taken into account in the reported emission level.

6.3. EMISSIONS FROM CATALYTIC REFORMING UNITS

There are limited references to emissions from catalytic reforming units (CRUs). The emission factors quoted in this report for CO and SO_X are from reference [14]. This paper uses combined emissions data from a number of units. As some of these units may have emission abatement controls installed, the factors may not truly represent uncontrolled emissions.

A review of the emissions for particulates and metals using the factors in reference [14] for a very high throughput CRU indicated that the estimated emissions were very small relative to other sources of these pollutants in a large refinery. No factors for these pollutants have therefore been provided.

7. METHANE (CH_4)

Estimation methods are provided for emissions due to:

- Combustion of fuels
- Destruction of gaseous streams in incinerators and flares
- Venting to atmosphere of uncontrolled blowdown systems

7.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 2**.

Table 2 CH_4 Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces < 10 MW (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	6.98E-01	[15] Section 4, Table 4.4a
	Refinery Fuel Oil	1.43E+00	[15] Section 4, Table 4.4a
	LPG	9.63E-01	[15] Section 4, Table 4.4a
	Natural Gas	1.08E+00	[15] Section 4, Table 4.4a
	Refinery Fuel Gas - hydrogen gas content < 65% v/v	3.26E-01	[15] Section 4, Table 4.4a
	Refinery Fuel Gas - hydrogen gas content ≥ 65% v/v	2.39E-01	[15] Section 4, Table 4.4a
Boilers and Furnaces 10 MW to 100 MW	Distillate (gas oil)	1.68E-01	[15] Section 4, Table 4.4a
	Refinery Fuel Oil	3.02E+00	[15] Section 4, Table 4.4a
	LPG	9.63E-01	[15] Section 4, Table 4.4a
	Natural Gas	1.08E+00	[15] Section 4, Table 4.4a

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces 10 MW to 100 MW	Refinery Fuel Gas - hydrogen gas content < 65% v/v	3.26E-01	[15] Section 4, Table 4.4a
	Refinery Fuel Gas - hydrogen gas content ≥ 65% v/v	2.39E-01	[15] Section 4, Table 4.4a
Boilers and Furnaces > 100 MW	Distillate (gas oil)	9.05E-01	[15] Section 4, Table 4.4a
	Refinery Fuel Oil	8.45E-01	[15] Section 4, Table 4.4a
	Natural Gas	1.08E+00	[15] Section 4, Table 4.4a
	Refinery Fuel Gas - hydrogen gas content < 65% v/v	3.26E-01	[15] Section 4, Table 4.4a
	Refinery Fuel Gas - hydrogen gas content ≥ 65% v/v	2.39E-01	[15] Section 4, Table 4.4a
Gas Turbine[1]	Natural Gas	4.11E+00	[15] Section 4, Table 4.5
Gas Engine 4-stroke, Lean Burn	Natural Gas	5.97E+02	[15] Section 4, Table 4.5
Diesel Engine[2] Large, Stationary	Diesel Fuel	3.67E+00	[15] Section 4, Table 4.5
Incinerator Support Fuel or Flare Pilot Fuel	LPG	9.63E-01	[15] Section 4, Table 4.4a
	Natural Gas	1.08E+00	[15] Section 4, Table 4.4a
	Refinery Fuel Gas - hydrogen gas content < 65% v/v	3.26E-01	[15] Section 4, Table 4.4a
	Refinery Fuel Gas - hydrogen gas content ≥ 65% v/v	2.39E-01	[15] Section 4, Table 4.4a

Notes:
1. Factor derived from turbines operating at high (≥ 80%) loads.
2. Factor is derived from data from one engine with 9% CH_4 by weight in the exhaust gas.

7.1.1. Other Fuels

In the absence of specific emission factors for other gaseous fuels (e.g. low joule gas) it is recommended to use the value of EF_{NCV} for natural gas from **Table 2**.

7.2. DESTRUCTION OF GASEOUS STREAMS

7.2.1. Flares

The following algorithms are for emissions from the combustion of the flare gas. For emissions from the combustion of the pilot gas fuel used to initiate flare combustion, use the algorithms in **Section 7.1**.

7.2.1.1. Flare Stream Details Known

If the mass and composition of the flare stream are known:

Mass emitted (kg) = 5.00E-00 × M × MF_{CH4}

where:
M = total mass of gas flared (in tonnes)
MF_{CH4} = mass fraction of methane in gas flared

This algorithm assumes that 0.5% of the hydrocarbons remain unburned in “well designed and operated flares, such as in refineries”.

Reference: [15], Section 4.4, Figure 4-2.

7.2.1.2. Flare Stream Details Unknown

If the mass and composition are not known and a flare gas recovery system is not installed, a conservative factor based on refinery feed can be used:

Mass emitted (kg) = 2.28E-05 × Refinery Feed (in m^3)

Reference: [15], Section 4.4, Table 4-7.

If a flare gas recovery system is installed it can be considered to be an emissions control device. The equation in **Section 6.1** can be used (with EFF = flare gas recovery system efficiency) to adjust the emissions estimate obtained from the algorithm above.

7.2.2. Incinerators

For all incinerator gas streams, use the algorithm in **Section 7.1** with an emission factor EF_{NCV} equal to that for natural gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 7.1**.

7.3. FUEL GAS SYSTEMS

Fugitive emissions can occur from the components e.g. valves, flanges, etc., in fuel gas lines containing methane. Emissions may be determined from leak monitoring surveys where CH_4 concentrations are measured, or calculated using equipment component counts (see **Section 13.5**). Where neither of these is available, a conservative emissions estimate can be obtained from:

Mass emitted (kg) = 3.00E-01 × M × MF_{CH4}

where:
M = total mass of fuel gas combusted (in tonnes)
MF_{CH4} = mass fraction of methane in fuel gas

Reference: [16], Appendix E.

7.4. UNCONTROLLED BLOWDOWN SYSTEMS

The gaseous emissions from blowdown systems in EU refineries are recovered and/or flared.

If these controls are not operational and all of the emissions are released to atmosphere, the total hydrocarbons emissions can be conservatively estimated using the factor provided in reference [6], Table 5.1-1. This reference states that methane comprises less than 1% by mass of the total hydrocarbon emissions.

8. CARBON MONOXIDE (CO)

Estimation methods are provided for emissions due to:

- Combustion of fuels
- Destruction of gaseous streams in incinerators and flares
- Partial burn regeneration of fluidised catalytic cracking units (FCCUs)
- Regeneration of catalytic reforming units

8.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 3**.

Table 3 CO Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces < 10 MW (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)[1]	1.62E+01	[17] Section 1.3, Table 1.3-1
	Refinery Fuel Oil[1]	1.51E+01	[17] Section 1.3, Table 1.3-1
	LPG[2]	3.71E+01	[17] Section 1.5, Table 1.5-1
	Natural Gas	3.93E+01	[17] Section 1.4, Table 1.4-1
Boilers and Furnaces 10 MW to 100 MW	Distillate (gas oil)[1]	1.62E+01	[17] Section 1.3, Table 1.3-1
	Refinery Fuel Oil[1]	1.51E+01	[17] Section 1.3, Table 1.3-1
	LPG[2]	3.71E+01	[17] Section 1.5, Table 1.5-1
	Natural Gas	3.93E+01	[17] Section 1.4, Table 1.4-1
Boilers and Furnaces > 100 MW	Distillate (gas oil)[1]	1.62E+01	[17] Section 1.3, Table 1.3-1
	Refinery Fuel Oil[1]	1.51E+01	[17] Section 1.3, Table 1.3-1
	LPG[2]	3.47E+01	[18] SCC 10101002
	Natural Gas	3.93E+01	[17] Section 1.4, Table 1.4-1

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Gas Turbine[3]	Distillate (gas oil)[4]	1.49E+00	[19] Section 3.1, Table 3.1-1
	Natural Gas	3.92E+01	[19] Section 3.1, Table 3.1-1
Gas Engine[5] 4-stroke, Lean Burn	Natural Gas	2.66E+02	[19] Section 3.2, Table 3.2-2
Diesel Engine Large, Stationary	Diesel Fuel	3.85E+02	[19] Section 3.4, Table 3.4-1
Incinerator Support Fuel or Flare Pilot Fuel	LPG[2]	3.71E+01	[17] Section 1.5, Table 1.5-1
	Natural Gas	3.93E+01	[17] Section 1.4, Table 1.4-1

Notes:

1. Reference [17], Table 1.3-1, note *e* states that CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.
2. Factor is for propane combustion.
3. Factor derived from turbines operating at high (≥ 80%) loads.
4. Factor provided in reference [19] was derived using HHV of 139 MBtu/10^3 US gal.
5. Factor derived from engines operating at < 90% load.

8.1.1. Other Fuels

In the absence of specific emission factors for other gaseous fuels (e.g. refinery fuel gas, low joule gas) it is recommended to use the value of EF_{NCV} for natural gas from **Table 3**.

8.2. DESTRUCTION OF GASEOUS STREAMS

8.2.1. Flares

The following algorithms are for emissions from the combustion of the flare gas. For emissions from the combustion of the pilot gas fuel used to initiate flare combustion, use the algorithms in **Section 8.1**.

8.2.1.1. Flare Stream Details Known

If the mass and composition of the flare stream are known:

Mass emitted (kg) = 1.77E-01 × M × NCV

where:
M = mass of flare gas combusted (in tonnes)
NCV = net calorific value of the flare gas combusted (in MJ/kg)

Reference: [20], Section 4.2.1, Table 8.

8.2.1.2. Flare Stream Details Unknown

If the mass and composition are not known and a flare gas recovery system is not installed, a conservative factor based on refinery feed can be used:

Mass emitted (kg) = 1.20E-02 × Refinery Feed (in m^3)

Reference: [21], Activity 090203, Section 8, Table 2.

If a flare gas recovery system is installed it can be considered to be an emissions control device. The equation in **Section 6.1** can be used (with EFF = flare gas recovery system efficiency) to adjust the emissions estimate obtained from the algorithm above.

8.2.2. Incinerators

For all incinerator gas streams, use the algorithm in **Section 8.1** with an emission factor EF_{NCV} equal to that for natural gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 8.1**.

8.3. CATALYTIC CRACKING UNIT REGENERATORS

CO is produced during the regeneration process and depends upon its severity. Emissions from partial burn regeneration are normally controlled with a CO boiler.

It is anticipated that EU refineries will estimate CO_2 emissions from FCCUs using the algorithm in **Section 9.3**. In this case, the CO emissions will be determined from measurements of flue gas flow and CO concentration.

Where the method in **Section 9.3** is not used, CO emissions can be estimated using the following:

8.3.1. Full Burn Regeneration

CO emissions are deemed to be negligible.

8.3.2. Partial Burn with CO Boiler

CO emissions are deemed to be negligible.

Reference: [6], Table 5.1-1.

8.3.3. Partial Burn without CO Boiler

If there is no CO boiler in operation:

Mass emitted (kg) = 3.92E+01 × Volume of fresh feed to unit (in m^3)

Reference: [6], Table 5.1-1.

8.4. CATALYTIC REFORMING UNITS

Mass emitted (kg) = 4.16E-02 × Volume of feed to unit (in m^3)

Reference: [14], Table 1. This reference uses data from a number of units with varying degrees of abatement equipment installed – see **Section 6.3**. It also provides data on the number of data points both above and below the limit of detection. The emission factor is a weighted value using both sets of data – see **Section 5.2** of this report.

9. CARBON DIOXIDE (CO_2)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators and flares
- Catalytic cracking unit regenerators
- Other catalyst regeneration e.g. in catalytic reforming units
- Fluid and Flexi-cokers
- Hydrogen plants

European refineries must estimate their CO_2 emissions under the terms of the EU greenhouse gas emission allowance trading scheme [22]. Reference [23] sets out detailed guidelines for the monitoring and reporting of CO_2 emissions.

9.1. COMBUSTION

Reference [23] specifies that CO_2 emissions from combustion installations be calculated by multiplying the energy content of each fuel used by an emission factor and an oxidation factor (default value equal to one). This requires the NCV of each fuel to be determined along with activity-specific emission factors.

The algorithm provided below applies the fundamental principle of complete stoichiometric combustion using the value of carbon content of the fuel. This approach reduces the emission calculation uncertainty as only carbon content has to be determined instead of values for both NCV and emission factor,

$$\text{Mass emitted (kg)} = 1000 \times M \times MF_{CARBON} \times CFC_{MW}$$

where:
M = mass of fuel burnt (in tonnes)
MF_{CARBON} = mass fraction of carbon in fuel
CFC_{MW} = Molecular weight conversion from C to CO_2 = (44.01/12.01) = 3.664

Thus for refinery oil and gaseous fuels:

$$\textbf{Mass emitted (kg)} = \mathbf{3.664E{+}03 \times M \times MF_{CARBON}}$$

9.2. DESTRUCTION OF GASEOUS STREAMS

9.2.1. Flares

The following algorithms are for emissions from the combustion of the flare gas. For emissions from the combustion of the pilot gas fuel used to initiate flare combustion, use the algorithm in **Section 9.1**.

9.2.1.1. Flare Stream Details Known

If the mass and composition of the flare stream are known, use algorithm in **Section 9.1**, where:
M = mass of flare gas burnt (in tonnes)
MF_{CARBON} = mass fraction of carbon in flare gas

[23] specifies this methodology for CO_2 reporting purposes by European refineries.

9.2.1.2. Flare Stream Composition Unknown

If the composition of the flare gas stream is not known, a conservative factor based on the combustion of ethane can be used:

Mass emitted (kg) = 3.93E+00 × Volume of gas flared (in m^3)

Reference: [23], Annex II, Section 2.1.1.3 (b).

9.2.1.3. Flare Stream Details Unknown

If both the mass and the composition of the flare gas stream are not known and a flare gas recovery system is not installed, a conservative factor based on refinery feed can be used:

Mass emitted (kg) = 3.14E+00 × Refinery Feed (in tonne)

Reference: [24], Section 3, Table 5.

If a flare gas recovery system is installed it can be considered to be an emissions control device. The equation in **Section 6.1** can be used (with EFF = flare gas recovery system efficiency) to adjust the emissions estimate obtained from the algorithm above.

9.2.2. Incinerators

Use algorithm in **Section 9.1**, where:
M = mass of gas incinerated (in tonnes)
MF_{CARBON} = mass fraction of carbon in gas incinerated

9.3. CATALYTIC CRACKING UNIT REGENERATORS

Reference [23] requires that emissions shall be calculated by a material balance approach, taking into account the state of the input air and the flue gas. Note that for CO_2 reporting, all CO in the flue gas shall be reported as CO_2.

[25] provides the following algorithm:

Mass emitted (kg) = $(AR + SR) \times (VF_{CO2} + VF_{CO}) \times CON_{VOL} \times TIME$

where:

AR = Air blower capacity (in m^3/minute)
SR = Supplemental oxygen addition rate (in m^3/minute)
VF_{CO2} = Volume fraction of CO_2 in flue gas
VF_{CO} = Volume fraction of CO in flue gas (prior to CO boiler if installed)
CON_{VOL} = Volume conversion factor at 15 C = 44 / MCF
MCF = Molar conversion factor at 15 C = (22.4 × 288 / 273) = 23.631 m^3/kgmole
TIME = time blower operated (in minutes)

Thus:

Mass emitted (kg) = 1.86E+00 × (AR + SR) × (VF_{CO2} + VF_{CO}) × TIME

Reference: [15], Section 5.2.1, equation 5-4.

9.3.1. FCCU With CO Boiler

Mass emitted (kg) = 1.86E+00 × (AR + SR) × (VF_{CO2} + VF_{CO}) × TIME

9.3.2. FCCU Without CO Boiler

Mass emitted (kg) = 1.86E+00 × (AR + SR) × VF_{CO2} × TIME

9.4. OTHER CATALYST REGENERATION

CO_2 is produced during the catalyst regeneration in reforming and hydro-processing units.

9.4.1. Flue Gas Flow and Composition Known

Reference [23] specifies that the method provided in **Section 9.3** should be used.

9.4.2. Flue Gas Details Unknown

The following algorithm conservatively assumes complete stoichiometric combustion of the carbon in the coke deposited on the catalyst. In practice there will be small emissions of CO (see **Section 8.4**).

Mass emitted (in kg) = 3.66E+03 × CR × MF_{CARB} × Feed

where:
CR = Mass ratio of coke produced per feed
MF_{CARB} = Mass fraction of carbon in coke
Feed = Feed to unit (in tonnes)

Reference: [15], Section 5.2.4.

9.5. COKERS

There are several varieties of cokers in use in refineries, including delayed cokers, fluid cokers, and flexi-cokers.

Delayed cokers will not have CO_2 emissions, other than from their process heaters [15]. These should be calculated using the fuel combustion algorithm in **Section 9.1**.

Fluid cokers and flexi-cokers may have a CO_2 vent resulting from the coke burner.

Reference [23] specifies that the method provided in **Section 9.3** should be used for flexi-cokers.

For cokers where flue gas flow and composition are unknown:

Mass emitted (in kg) = 3.66E+03 × CR × MF_{CARB} × Feed

where:
CR = Mass ratio of coke produced per feed
MF_{CARB} = Mass fraction of carbon in coke
Feed = Feed to unit (in tonnes)

Reference: [15], Section 5.2.3.

If the burner off-gas is burned as a low joule gas fuel, the subsequent emissions should be calculated using the fuel combustion algorithm in **Section 9.1**.

9.6. HYDROGEN PLANTS

CO_2 is produced during the hydrogen production process.

9.6.1. Feed Composition Data Known

Reference [23] specifies that emissions should be calculated from the carbon content of the feed gas.

Mass emitted (kg) = 3.66E+03 × MF_{CARB} × Feed

where:
MF_{CARB} = mass fraction of carbon in feed gas
Feed = Feed to unit (in tonnes)

9.6.2. Feed Composition Data Unknown

If the composition of the feed gas is not known, a conservative factor based on an ethane feed can be used:

Mass emitted (kg) = 2.90E+03 × Feed to unit (in tonnes)

Reference: [23], Annex III, Section 2.1.2.2 (b).

10. HYDROFLUOROCARBONS (HFC)

Hydrofluorocarbons (HFCs) may be used as refrigerants in refinery thermal exchange equipment.

Emissions are assumed to equal the amount used during the reporting period to top-up systems to replenish losses due to uncontrolled leakage.

Mass emitted (kg) = Mass used to top-up refrigerant systems (in kg)

Usage where the systems have been fully or partially drained and refrigerants collected for recycling or destruction should not be reported.

11. NITROUS OXIDE (N_2O)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators

11.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 4**.

Table 4 N_2O Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	8.40E-01	[15] Section 4, Table 4.4a
	Refinery Fuel Oil	1.60E+00	[15] Section 4, Table 4.4a
	LPG	4.33E+00	[15] Section 4, Table 4.4a
	Natural Gas	1.03E+00	[15] Section 4, Table 4.4a
	Natural Gas (where low NO_X burners fitted)	3.00E-01	[15] Section 4, Table 4.4a
Gas Turbine[1]	Natural Gas	1.43E+00	[15] Section 4, Table 4.5
Gas Engine 4-stroke, Lean Burn	Natural Gas	Not Detected[2]	[15] Section 4, Table 4.5
Diesel Engine Large, Stationary	Diesel Fuel	2.21E+00	[15] Section 4, Table 4.5
Incinerator Support Fuel or Flare Pilot Fuel	LPG	4.33E+00	[15] Section 4, Table 4.4a
	Natural Gas	1.03E+00	[15] Section 4, Table 4.4a

Notes:

1. Factor based on limited source tests on a single turbine with water-steam injection and operating at high (≥ 80%) loads.

2. Compound was not detected. The emission factor stated in reference [15] represents the detection limit. For the purposes of this report the emission factor is considered to be zero as source not proven (See **Section 5.2** of this report).

11.1.1. Other Fuels

In the absence of specific emission factors for other gaseous fuels (e.g. refinery fuel gas, low joule gas) it is recommended to use the value of EF_{NCV} for natural gas from **Table 4**.

11.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 11.1** with an emission factor EF_{NCV} equal to that for natural gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 11.1**.

12. AMMONIA (NH_3)

Estimation methods are provided for emissions from:

- Selective Non-Catalytic NO_X Reduction (SNCR) systems
- Selective Catalytic NO_X Reduction (SCR) systems
- Refrigeration systems
- Catalytic Cracking Unit Regenerators

12.1. NO_X REDUCTION SYSTEMS

Ammonia is produced as a by-product by SCR and SNCR systems installed in flues to reduce NO_X emissions.

12.1.1. SNCR

The emission algorithms are:

Mass emitted (kg) = 3.50E-01 × V_{OIL}

or

Mass emitted (kg) = 2.88E+02 x V_{GAS}

where:
V_{OIL} = Volume of oil combusted in device connected to SNCR (in m^3)
V_{GAS} = Volume of gas combusted in device connected to SNCR (in million m^3)

Reference: [26], Section 5.4, Table 5-5.

12.1.2. SCR

The emission algorithms are:

Mass emitted (kg) = 1.70E-01 × V_{OIL}

or

Mass emitted (kg) = 1.46E+02 x V_{GAS}

where:
V_{OIL} = Volume of oil combusted in device connected to SCR (in m^3)
V_{GAS} = Volume of gas combusted in device connected to SCR (in million m^3)

Reference: [26], Section 5.4, Table 5-5.

12.2. REFRIGERATION SYSTEMS

Ammonia may be used as a refrigerant in refinery thermal exchange equipment.

Emissions are assumed to equal the amount used during the reporting period to top-up systems to replenish losses due to uncontrolled leakage.

Mass emitted (kg) = Mass used to top-up refrigerant systems (in kg)

Usage where the systems have been fully or partially drained and refrigerants collected for recycling or destruction should not be reported.

12.3. CATALYTIC CRACKING UNIT REGENERATORS

NH_3 is produced during the regeneration process and depends upon its severity. Emissions from partial burn regeneration are normally controlled by a CO boiler.

12.3.1. Full Burn Regeneration

Emissions are deemed to be negligible

Reference: [27], Section 9.3.4.

12.3.2. Partial Burn with CO Boiler

Emissions are deemed to be negligible

Reference: [27], Section 9.3.4.

12.3.3. Partial Burn without CO Boiler

If there is no CO boiler in operation:

Mass emitted (kg) = 1.55E-01 × Volume of fresh feed to unit (in m^3)

Reference: [26], Section 4, Table 4.1.

13. NON-METHANE VOLATILE ORGANIC COMPOUNDS (NMVOC)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators and flares
- Catalytic cracking unit regenerators
- Fluid cokers
- Components under pressure e.g. pumps and valves (“fugitives”)
- Process drains
- Oil-water separators
- Loading of mobile containers (rail-cars, road tankers, ships and barges)
- Storage tanks
- Venting to atmosphere of uncontrolled blowdown systems
- Uncontrolled bitumen blowing

The driver for reporting VOC emissions is photochemical production of ozone. Methane has a negligible photochemical reactivity. In Europe this compound is therefore excluded from the “basket” of reactive VOCs which are collectively referred to as non-methane volatile organic compounds (NMVOC). The US EPA also considers ethane to have a significantly low reactivity. A number of emission factors developed by the EPA, therefore, are for non-(methane and ethane) VOCs. Those NMVOC emission factors provided in this section which exclude ethane emissions are identified.

13.1. COMBUSTION OF FUELS

Mass emitted (kg) = $(EF_{NCV} \times M \times NCV) / 1000$

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 5**.

Table 5 NMVOC Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces < 10 MW (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	1.10E+00	[17] Section 1.3, Table 1.3-3
	Refinery Fuel Oil	3.41E+00	[17] Section 1.3, Table 1.3-3
	LPG[1]	3.96E+00	[17] Section 1.5, Table 1.5-1
	Natural Gas[2]	2.58E+00	[17] Section 1.4, Table 1.4-2

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces 10 MW to 100 MW	Distillate (gas oil)	6.47E-01	[17] Section 1.3, Table 1.3-3
	Refinery Fuel Oil	8.45E-01	[17] Section 1.3, Table 1.3-3
	LPG[1]	3.96E+00	[17] Section 1.5, Table 1.5-1
	Natural Gas[2]	2.58E+00	[17] Section 1.4, Table 1.4-2
Boilers and Furnaces > 100 MW	Distillate (gas oil)	2.46E+00	[17] Section 1.3, Table 1.3-3
	Refinery Fuel Oil	2.29E+00	[17] Section 1.3, Table 1.3-3
	LPG[2]	2.27E+00	[18] SCC 10101002
	Natural Gas[2]	2.58E+00	[17] Section 1.4, Table 1.4-2
Gas Turbine[2, 3]	Distillate (gas oil)[4]	1.86E-01	[19] Section 3.1, Table 3.1-2a
	Natural Gas	1.00E+00	[19] Section 3.1, Table 3.1-2a
Gas Engine[2] 4-stroke, Lean Burn	Natural Gas	5.64E+01	[19] Section 3.2, Table 3.2-2
Diesel Engine[5] Large, Stationary	Diesel Fuel	3.71E+01	[19] Section 3.4, Table 3.4-1
Incinerator Support Fuel or Flare Pilot Fuel	LPG[1]	3.96E+00	[17] Section 1.5, Table 1.5-1
	Natural Gas[2]	2.58E+00	[17] Section 1.4, Table 1.4-2

Notes:
1. Factor is for propane combustion. Derived by subtracting the emissions factor for methane from that for total organic compounds.
2. Factor excludes ethane emissions.
3. Factor derived from turbines operating at high (≥ 80%) loads
4. Factor provided in reference [19] was derived using HHV of 139 MBtu/10^3 US gal.
5. Based on data from one engine with exhaust gas TOC composition by weight of 91% NMVOCs.

13.1.1. Other Fuels

In the absence of specific emission factors for other gaseous fuels (e.g. refinery fuel gas, low joule gas) it is recommended to use the value of EF_{NCV} for natural gas from **Table 5**.

13.2. DESTRUCTION OF GASEOUS STREAMS

13.2.1. Flares

The following algorithms are for emissions from the combustion of the flare gas. For emissions from the combustion of the pilot gas fuel used to initiate flare combustion, use the algorithm in **Section 13.1**.

13.2.1.1. Flare Stream Details Known

If the mass and composition of the flare stream are known:

Mass emitted (kg) = 5.00E-00 × M × MF_{NMVOC}

where:
M = total mass of gas flared (in tonnes)
MF_{NMVOC} = mass fraction of NMVOC in gas flared

This algorithm assumes that 0.5% of the hydrocarbons remain unburned in “well designed and operated flares, such as in refineries”.

Reference: [15], Section 4.4.

13.2.1.2. Flare Stream Details Unknown

If the mass and composition are not known and a flare gas recovery system is not installed, a conservative factor based on refinery feed can be used:

Mass emitted (kg) = 2.00E-03 × Refinery Feed (in m^3)

This factor is for total unburned hydrocarbons. Comparison with the emission factor for methane (**Section 7.2.1.2**) indicates that methane is assumed to constitute about 1% by mass of the total unburned hydrocarbons.

Reference: [21], Activity 090203, Section 8, Table 2.

If a flare gas recovery system is installed it can be considered to be an emissions control device. The equation in **Section 6.1** can be used (with EFF = flare gas recovery system efficiency) to adjust the emissions estimate obtained from the algorithm above.

13.2.2. Incinerators

For all incinerator gas streams, use the algorithm in **Section 13.1** with an emission factor EF_{NCV} equal to that for natural gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 13.1**.

13.3. CATALYTIC CRACKING UNIT REGENERATORS

NMVOCs are produced during the regeneration process. Emissions from units operating with partial burn regeneration are normally controlled with a CO boiler.

13.3.1. Full Burn Regeneration

Emissions are deemed to be negligible

13.3.2. Partial Burn with CO Boiler

Emissions are deemed to be negligible

Reference: [6], Table 5.1-1.

13.3.3. Partial Burn without CO Boiler

If there is no CO boiler in operation:

Mass emitted (kg) = 6.30E-01 × Volume of fresh feed to unit (in m^3)

This factor is for total hydrocarbons (THC). Reference [6] states that, overall, less than 1% by mass of THC emissions is methane.

Reference: [6], Table 5.1-1.

13.4. FLUID COKERS

If the off-gas is not fed to a CO boiler, or it is not in operation:

Mass emitted (kg) = 4.60E-02 × Feed to unit (in m^3)

Reference: [20], Section 4.2.1, Table 8.

13.5. FUGITIVE EMISSIONS FROM PRESSURISED COMPONENTS

Emissions can occur due to leakage past seals on components installed in pressurised pipework or process plant e.g. valves, pumps, flanges, etc.

Emission estimates can be made by:

- Measuring the VOC concentration adjacent to potential leak points and estimating the emission flux using correlation equations or emission factors.
- Detecting leaks using optical gas imaging.
- Using average emission factors for individual types of components and their process service, where the number of components is known.
- Using a conservative overall emission factor based on refinery throughput.

Note that this Section does not deal with emissions from low pressure equipment such as drains, oil-water separators, loading systems and product storage tanks. Emission estimation methodologies for these sources are provided separately – see **Sections 13.6**, **13.8** and **13.9**.

13.5.1. Leak Detection Surveys Undertaken

Leaking components can be identified either using a conventional hydrocarbon monitor to measure the VOC concentration adjacent to potential leak points or an optical gas imaging (OGI) camera can be used to visualise gas leaks remotely.

This report does not provide details of the measurement methods. A CONCAWE Report [28] provides a comparative review of conventional and OGI techniques for leak detection.

13.5.1.1. Conventional Hydrocarbon Monitor

This method requires the “screening” of leak sources by measuring the concentration of VOCs at the surface of each potential source using a conventional hydrocarbon monitor. The local VOC concentration (“screening value”) at the surface of a leak source is converted into an emission flux using a correlation equation or emission factors.

Details of the methodologies and the calculation of emissions are provided by the US EPA [29] and in the European CEN Standard on fugitive emission estimation [30].

13.5.1.2. Optical Gas Imaging Camera

In this method emissions are estimated using a “leak” / “no-leak” criterion where the emission factor used depends on the "leak" detection sensitivity of the camera. The emission factors for each equipment type for specified camera detection limits are provided in **Table 6.**

The emissions can be calculated for each equipment type and service using:

$$\textbf{Mass emitted (kg)} = [(F_{LEAK} \times N_{LEAK}) + (F_{NO\text{-}LEAK} \times N_{NO\text{-}LEAK})] \times \textbf{TIME}$$

where:
F_{LEAK} = Emission factor for leaking components according to the detection limit of the camera
N_{LEAK} = Number of components identified as leaking
$F_{NO\text{-}LEAK}$ = Emission factor for non-leaking components according to the detection limit of the camera
$N_{NO\text{-}LEAK}$ = Number of components identified as not leaking
TIME = Time that the equipment is in operation and pressurised (in hours).

Details of the methodology and the calculation of emissions are provided in Concawe report 6/08 [28] and in reference [31].

Table 6 Leak/No-Leak Emission Factors where optical gas imaging (OGI) is used to detect leaks

Equipment Type	Factor Type	Emission Factor for Specified OGI Leak Definition for different camera sensitivity settings kg/hr/source			
		3 g/hr	6 g/hr	30 g/hr	60 g/hr
Valves	Leak	5.50E-02	7.30E-02	1.40E-01	2.00E-01
	No-Leak	1.90E-05	4.30E-05	1.70E-04	2.70E-04
Pumps	Leak	1.40E-01	1.60E-01	3.10E-01	3.50E-01
	No-Leak	9.60E-05	1.30E-04	5.90E-04	7.50E-04
Flanges	Leak	2.90E-02	4.50E-02	8.80E-02	1.20E-01
	No-Leak	2.60E-06	4.10E-06	1.00E-05	1.40E-05
All other components	Leak	5.60E-02	7.50E-02	1.50E-01	2.10E-01
	No-Leak	7.00E-06	1.40E-05	5.10E-05	8.10E-05

Reference: [31]

Definitions of "Service"

Reference [30] provides the following definitions for "service":

- Gas service: equipment which in use contains process fluid that is in the gaseous state at operating conditions.
- Light liquid service: equipment which in use contains hydrocarbon streams of which at least 20% wt has a vapour pressure in excess of 0.3 kPa at 20ºC. For example, this includes automotive and aviation gasolines and crude oil. It excludes products such as kerosenes and gasoils.

13.5.2. Leak Detection Surveys Not Undertaken

13.5.2.1. Component Data Available

Where no monitoring (or only a partial survey) has been undertaken, the emissions from un-surveyed equipment can be calculated using:

Mass emitted (kg) = $\mathbf{F_{COMP} \times N \times TIME}$

where:
F_{COMP} = Average emission factor for the particular equipment type as in **Table 7**.
N = Number of pieces of equipment grouped in the relevant category according to the equipment type, service and operation.
TIME = Time that the equipment group is in operation and pressurised (in hours).

This algorithm is conservatively high as it assumes that the product contained within the equipment components wholly comprises NMVOCs i.e. it does not account for non-NMVOC components contained within the fugitive emission. However, the non-

NMVOC emissions will mainly be methane e.g. from fuel gas, and this has the lowest density of the hydrocarbons emitted. For fuel gas systems this can be compensated for; see **Section 7.3** for methane emission estimation. Moreover, the number of equipment components in pipelines containing low concentration NMVOC streams (e.g. low joule gas) is generally a very small percentage of the total components on a refinery.

Table 7 Average Emission Factors for Components

Equipment Type	**Service**	**Emission Factor kg/hr/source**
Valves	Gas	2.68E-02
	Light Liquid	1.09E-02
Pump seals	Light Liquid	1.14E-01
Compressor seals	Gas	6.36E-01
Pressure relief valves	Gas	1.60E-01
Flanges and non-flanged connectors	All	2.50E-04
Open-ended lines	All	2.30E-03
Sampling connections	All	1.50E-02

Reference: [30]

<u>Component counts</u>

The count can be based on up-to-date piping and instrumentation diagrams, equipment lists, operating manuals or physical component counts. The count should include spare components if these are filled with process fluid and are pressurised.

If actual counts are not available, an extrapolation can be made from published information. Reference [32] cites an example of a US refinery of 52 500 m^3/day capacity having 11 500 valves, 46 500 flanges, 350 pump seals, 70 compressor seals and 100 relief valves.

Alternatively, reference [27], Section 3.4.1, Table 3-1, provides the following “average” refinery data:

Emission Source Component	**Gas**	**Liquid**
Valves per pump or compressor	133	41
Flanges per valve	4.1	4.1
Mixer seals per mixer	-	1
Pump seals per pump	-	1.35
Compressor seals per compressor	2	-

13.5.2.2. No Component Data Available

A conservative emission factor can be used if no data on components are available:

Mass emitted (kg) = 2.00E-01 × Refinery feed (in tonnes)

Reference: [5], Chapter 1.B.2.a.iv, Table 3-6.

13.6. OILY-WATER COLLECTION AND TREATMENT SYSTEMS

Contaminated waste water systems principally comprise process drains and a water treatment facility, such as a gravity separator. The emissions from oily-water systems vary significantly with time, depending, for example, on the amount and volatility of the entrained oil, waste water temperature, flow, etc.

Emissions can be estimated for the entire system using complex models available as software packages (see **Section 13.6.1**).

Alternatively, the emissions from the process drains and the separator systems can be estimated separately (see **Sections 13.6.2** and **13.6.3**).

13.6.1. Emission Estimation Models For Entire System

There are a number of complex estimation models available to calculate emissions from waste water systems. They aim to estimate average emission rates of individual species for each of the system components, collectively permitting the determination of the overall emissions from a refinery wastewater collection and treatment system.

The US EPA has developed a freely available computer program model called WATER9 [33]. This is Windows based and consists of analytical expressions for estimating air emissions of individual waste constituents in waste water collection, storage, treatment, and disposal facilities. Reference [34] provides the mathematical equations used in this model.

It should be noted that the input data demands of the model are large and require considerable sampling and analyses to be undertaken. However, it is likely that the increased level of characterisation of the hydrocarbons present in the refinery's waste water will lead to more accurate estimation of emissions than the more simple emission factor approach.

13.6.2. Process Drains

The following algorithm provides an estimate for emissions from the entire refinery process drain system in oily-water service. Note that drain systems on clean water (with minimal potential for contact with oil) and storm water are excluded.

Process drains and junction boxes are normally fitted with an emission control device such as a water seal or sealed cover. An assessment needs to be made to establish how many of the drain covers are unsealed and vent directly to atmosphere.

Mass emitted (kg) = 3.20E-02 × N × TIME

where:
N = number of <u>unsealed</u> drain openings in the refinery process drain system.
TIME = period of emission estimate in hours (for E-PRTR annual reports = 8760)

This factor excludes ethane emissions.

Reference: [27], Section 7.5, Table 7-3.

13.6.3. Oil-Water Separators

Emissions from separators can be determined using simple emission factors which are known to give conservatively high estimates. Alternatively, an algorithm can be used for uncovered gravity separators which requires, as a minimum, data on separator inlet flow and entrained oil concentration. Sampling and analysis thus have to be undertaken and due to the temporal variability of the input parameters the estimation accuracy will depend on the frequency of testing.

13.6.3.1. Gravity Separator - where separator inlet monitoring data available

An estimate for the emissions from uncovered API type separators is provided by:

Mass emitted (kg) = $1.00E\text{-}04 \times D \times V \times (5.74 \times T_{AMB} - 5.15 \times T_{DP} + 38.6 \times T_{WW} + 33.6) \times TIME$

where:
D = liquid density of evaporated hydrocarbons (kg/m^3). If unknown, [36] provides a default average value of 660 kg/m^3
V = flow rate of hydrocarbons entering the separator (m^3/h). Calculated from data on waste water flow and concentration of hydrocarbons in the waste water.
T_{AMB} = ambient water temperature (°C)
T_{DP} = 10% distillation point (°C). If unknown, [36] provides a default average value of 150°C
T_{WW} = Waste water temperature (°C)
TIME = period of emission estimate in hours (for E-PRTR annual reports = 8760)

Reference: [35], developed in reference [36], Section 5.2.

Where a cover is fitted to a gravity separator, the emissions abatement efficiency can be assumed to be 97% [27].

13.6.3.2. Simple Algorithms

These algorithms assume emissions to be dependent solely on the type of separator installed.

Mass emitted (kg) = $EF_{SEP} \times VOL_{WATER}$

where:
EF_{SEP} = Emission factor for the type of separator given in **Table 8**.
VOL_{WATER} = Volume of waste water treated by the separator (in m^3).

Table 8 Emission Factors for Oil-Water Separators

SEPARATOR TYPE	EMISSION FACTOR (EF_{SEP})[1] kg/m^3 waste water treated
Gravity type – uncovered[2]	1.11E-01
Gravity type – covered	3.30E-03
Gravity type – covered and connected to flare	0
DAF[3] or IAF[4] – uncovered[5]	4.00E-03
DAF or IAF – covered[5]	1.20E-04
DAF or IAF – covered and connected to flare	0

Notes:

1. These factors exclude ethane emissions
2. Measurements on uncovered gravity type waste water treatment plants at two Canadian refineries varied by two orders of magnitude [27]. The factor provided here was confirmed by the greater of these measurements
3. DAF = Dissolved air floatation type
4. IAF = Induced air floatation type
5. The emission factors for these types of separator apply where they are installed as secondary treatment systems.

Reference: [27], Section 7.5, Table 7-3.

Emissions from basins and ponds that handle clean water or storm water are considered negligible.

For ponds temporarily storing oily-water, use the emission factor for an uncovered, gravity type separator from **Table 8**.

13.7. COOLING WATER TOWERS

Emissions from cooling water towers are considered negligible as sound refinery engineering practice ensures that oil is prevented from entering these systems.

Guidance on estimating emissions if a heat exchanger oil leak has occurred and monitoring data are unavailable is provided in reference [27], Section 7.7.5.

13.8. LOADING OF MOBILE CONTAINERS

Emissions from the loading of mobile containers (i.e. road tankers, rail tank cars, barges and marine tankers) depend upon the type of container being loaded and the degree of saturation of the vapour in the cargo tank. For example, uncontrolled emissions from road tankers depend upon the mode of loading (i.e. top loading with a drop pipe through an open hatch or bottom loading through pipework connected on the tanker) and if the tanker delivers product to a facility with a “vapour balancing” system installed. In this type of system, the vapours displaced from the storage tank being filled by the tanker are fed back into the tanker compartment to “balance” the off-loaded product. The tanker thus returns to the loading facility with the compartments filled with vapour.

Emissions from loading can be controlled with a vapour recovery unit (VRU) or thermal oxidiser. Algorithms for VRUs are given below. Emissions from thermal oxidisers can be calculated using the algorithms listed in this report for incinerators.

13.8.1. Uncontrolled Emissions

$$\textbf{Mass emitted (kg)} = EF_{LOAD} \times VOL_{LOAD} \times TVP$$

where:
EF_{LOAD} = Emission Factor from **Table 9**, depending on loading mode.
VOL_{LOAD} = Volume of product loaded (in m^3).
TVP = True Vapour Pressure of product at loading temperature (in kPa).

Reference: [7], Section 3.

For gasolines, TVP can be calculated from:

$$TVP = RVP \times 10^{[(7.047E\text{-}06 \times RVP + 1.392E\text{-}02) \times TEMP + (2.311E\text{-}04 \times RVP - 5.236E\text{-}01)]}$$

where:
RVP = Reid Vapour Pressure (in kPa)
TEMP = product loading temperature (in degrees Centigrade)

Reference: [7], Appendix 1.

Table 9 NMVOC Emission Factors for Loading of Mobile Containers

LOADING MODE	EMISSION FACTOR EF_{LOAD} $kg/m^3/kPa$
Road Tanker, Bottom Loading No Vapour Balancing during Previous Off-Loading	8.60E-03
Road Tanker, Top Loading No Vapour Balancing during Previous Off-Loading	9.40E-03
Road Tanker, Bottom or Top Loading Vapour Balancing during Previous Off-Loading	2.28E-02
Rail Tanker, Top Loading	1.08E-02
Rail Tanker, Bottom Loading[1]	1.05E-02
Marine tanker - typical cargo tank condition[2,3]	3.91E-03
Barge - typical cargo tank condition[2,3]	7.45E-03

Notes:

1. During the top loading of rail tankers emissions occur from the open loading hatch both before and after loading [7]. As there is no open hatch during bottom loading of a rail tanker, this factor assumes no pre- or post-loading emissions.
2. Value corrected from that published in [7].
3. These factors are for typical cargo tank vapour conditions. For other situations (e.g. tank gas freed or ballasted, previous cargo non-volatile, etc.) specific emission factors are provided in reference [6], Table 5.2-2 for the loading of gasoline with a TVP of 55 kPa. These factors should be prorated for the value of the TVP of the product loaded.

13.8.2. Emissions Controlled with a Vapour Recovery Unit (VRU)

VRUs may be fitted with a continuous emissions monitor (CEM) or the recovery efficiency may be known from tests.

13.8.2.1. VRU Fitted with a CEM

$$\textbf{Mass emitted (kg)} = 1.00E\text{-}03 \times MEAS_{CONC} \times VOL_{LOAD} \times (1 - TVP / 100)$$

where:
$MEAS_{CONC}$ = Measured VRU vent concentration (in g/m^3)
VOL_{LOAD} = Volume of product loaded (in m^3)
TVP = True Vapour Pressure of product at loading temperature (in kPa)

Reference: [7], Section 3.2.

13.8.2.2. VRU Efficiency Known

Emissions should be calculated using the algorithm in **Section 6.1**.

13.9. STORAGE TANKS

Emissions from storage tanks comprise two components:

- Working loss; emissions due to the tank being filled (displacing vapours above the product stored) or emptied (evaporation of product “clingage” on tank internal walls)
- Standing losses: emissions due to the expansion of the vapour space in fixed roof tanks due to vapour temperature or pressure changes and leakage past equipment (e.g. seals, still wells, etc.) fitted to floating roofs.

13.9.1. Floating Roof Tanks

Floating roof tanks can be of the following types:

- External floating roof (EFR)
- EFR fitted with domed cover
- Internal floating roof (IFR)
  - fitted with open vents in the fixed roof
  - fitted with vents in the fixed roof which can be closed e.g. pressure/vacuum valves, connected to a vapour recovery unit, etc.

For all of these tank types except IFR tanks which are not freely vented, use the latest edition of reference [37]. For IFR tanks fitted with vents which can be closed, guidance is provided in reference [38] which shows that emissions from closed-vent internal floating roof tanks are approximately 5% less than emissions from internal floating roof tanks with open vents determined in accordance with [37].

Methodologies to estimate the emissions when the roof has landed on its legs and is no longer floating on the product are provided in reference [39].

13.9.2. Vertical Fixed Roof Tanks (VFRT)

For these tanks in normal service, use the latest edition of reference [40].

13.9.2.1. VFRTs Connected to a Vapour Holding Tank (VHT)

A vapour holding tank comprises a fixed roof tank containing a flexible diaphragm. Where connected to a storage tank, a correctly sized VHT stores any emissions from the tank due to the rise in vapour temperature during the day, and then releases these vapours back to the tank as it cools at night. The VHT, therefore, controls the "standing losses".

Emissions, therefore, can be assumed to equal only the "working losses".

13.9.3. Aboveground Horizontal Tanks

For these tanks, use the latest edition of reference [41], Section 7.1.3.1.

13.9.4. Underground Tanks

Use the algorithms for service station storage tanks provided in **Appendix 4.2**.

13.9.5. Tank Cleaning

Guidance on the estimation of evaporative emissions during tank cleaning is provided in reference [42].

13.9.6. Storage Tanks - General Comments

Reference [41] normally contains the latest versions of references [37], [39] and [40]. Emission calculation software utilising the algorithms in reference [41] is available from the US EPA via their website, http://www.epa.gov, or on a CD-ROM [43]. This CD also contains the EPA publication AP-42 *Compilation of Air Pollutant Emission Factors* and references [29], [34].

It should be noted that some options are provided in the algorithms in references [37] to [41] to cover the state of equipment; e.g. degrees of rust on tank internal shells, tightness of floating roof seals, etc. Users of the algorithms, therefore, must ensure that the factors utilised to derive emissions for a particular tank are appropriate. In particular, the API states that the algorithms are only 'applicable to properly maintained equipment under normal working conditions'

13.10. UNCONTROLLED BLOWDOWN SYSTEMS

The gaseous emissions from blowdown systems in EU refineries are recovered and/or flared.

If these controls are not operational and all of the emissions are released to atmosphere, the total hydrocarbons emissions can be conservatively estimated using the factor provided in reference [6], Table 5.1-1.

13.11. UNCONTROLLED BITUMEN BLOWING

The gaseous emissions from bitumen blowing in EU refineries are controlled, for example using scrubbers and incinerators.

Where these controls are not operational and all of the emissions are emitted to atmosphere, the emissions can be estimated using the factor in reference [21], Activities 040101 & 040102, Section 8.2.1, Table 8.2.

14. NITROGEN OXIDES (NO_X)

Estimation methods are provided for emissions of NO_X from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators and flares
- Catalytic cracking unit regenerators

14.1. COMBUSTION IN BOILERS AND FURNACES

NO_X emissions from combustion comprise two components:

- Thermal NO_X; this is the thermal fixation of molecular nitrogen and is generally a function of flame temperature, residence time and oxygen concentration in the flame zone
- Fuel NO_X; this is the result of the direct oxidation of the nitrogen in liquid fuels or the non-inert nitrogen containing species in gaseous fuels.

The following methodology is outlined in more detail, with an example, in reference [44].

Total NO_X Emissions = Thermal NO_X + Fuel NO_X

<u>Thermal NO_X</u>

Thermal NO_X Mass emitted (kg) = 1.00E-03 × TNF × M × HHV

where:
TNF = Thermal NO_X factor (in g/GJ)
M = Mass of fuel combusted (in tonnes)
HHV = Higher heating value of the fuel combusted (in MJ/kg)
For liquid fuels
HHV = 1.05 × NCV
For gaseous fuels
HHV = 1.11 × NCV
where NCV = Net calorific value (in MJ/kg)

$$TNF = F_{BASE} \times F_{H2} \times F_{CONTROL} \times F_{PREHEAT} \times F_{H_2O} \times F_{LOAD} \times F_{BURN}$$

F_{BASE} is the base fuel factor. This accounts for differences in flame temperature due to fuel composition and is therefore dependent on the type of fuel burnt. Values for different fuels are given in **Table 10**.

Table 10 Values for F_{BASE}

FUEL	F_{BASE} (g/GJ) (HHV)
Methane, Natural Gas, LPG	56
Refinery Fuel Gas	69
Low Joule Gas	30
Refinery Fuel Oil, Distillates	56

F_{H2} is the adjustment factor for the amount of hydrogen gas in the fuel.

For all liquid fuels, methane, natural gas and LPG: F_{H2} = 1.0

For other refinery gaseous fuels, values for F_{H2} are given for some hydrogen concentrations in **Table 11**. These can be used to extrapolate for other compositions.

Table 11 Values for F_{H2}

FUEL	H_2 CONCENTRATION % v/v	F_{H2}
Refinery Fuel Gas	0 - 23	1.00
	33	1.04
	43	1.09
	63	1.25
	83	1.46
Low Joule Gas	0 - 14.7	1.00
	24.7	1.04
	34.7	1.09
	54.7	1.25
	74.7	1.46

$F_{CONTROL}$ is the adjustment factor for at-the-source control technologies, including burner type. Values are given in **Table 12**.

Table 12 Values for $F_{CONTROL}$

CONTROL TECHNOLOGY		$F_{CONTROL}$
None		1.00
Low NOX burner, staged fuel		0.33
Low NOX burner, staged air		0.60
Ultra-low NOx burner		0.30
Flue Gas Recirculation	0%	1.00
	5%	0.60
	10%	0.40
	15%	0.30
	20%	0.20

$F_{PREHEAT}$ is the adjustment factor for the average air preheat temperature. Values are given in **Table 13**.

Table 13 Values of $F_{PREHEAT}$

AIR PREHEAT TEMPERATURE Degrees C	$F_{PREHEAT}$
< 38	1.00
38	1.00
93	1.10
149	1.32
204	1.60
260	1.86

F_{H_2O} is the adjustment factor for the moisture content of the combustion air. Values are given in **Table 14**.

Table 14 Values of F_{H_2O}

MOISTURE CONTENT kg H_2O / kg dry air	F_{H_2O}
0	1.00
0.01	0.79
0.02	0.67
0.03	0.53
0.04	0.41
0.05	0.29

F_{LOAD} is the adjustment factor for the loading of the combustion unit. For dual fuel firing, the load is calculated using the total thermal input. Values are given in **Table 15**.

Table 15 Values of F_{LOAD}

LOAD (% of design)	F_{LOAD}
40	0.55
60	0.70
80	0.85
100	1.00

F_{BURN} is the adjustment factor for the burner intensity, a measure of the heat release per volume of burner space. There is no precise measure for burner intensity. Where no combustion unit information on intensity is available, in general high intensity burners are used for packaged boilers and pyrolysis furnaces and low intensity burners are used for all other fired heaters and boilers. Where furnace (radiant cell) volume is known, then the classification can be ascertained from:

- High intensity is > 700 KW/m^3
- Low intensity is < 30 kW/m^3

Values for F_{BURN} are given in **Table 16**.

Table 16 Values for F_{BURN}

BURNER INTENSITY	F_{BURN}
High	1.8
Low	1.0

<u>Fuel NO_X</u>

Fuel NO_X Mass emitted (kg) = 1.00E-03 × FNF × M × HHV

where:
FNF = Fuel NO_X factor (in g/GJ)
M = Mass of fuel combusted (in tonnes)
HHV = Higher Heating Value of the fuel combusted (in MJ/kg)

FNF = (1.00E+04 × $MP_{NITROGEN}$ × CFN_{MW} × $F_{N2CONTENT}$) / HHV

where:
$MP_{NITROGEN}$ = Mass Percentage of Nitrogen in the fuel combusted
CFN_{MW} = Molecular weight conversion from N to NO_2 = 46 / 14 = 3.286
$F_{N2CONTENT}$ = Adjustment factor for nitrogen content. Values are given in **Table 17.**

Table 17 Values for $F_{N2CONTENT}$

FUEL NITROGEN % m/m	$F_{N2CONTENT}$	
	Uncontrolled Burner	Low-NOx burner with staged air
< 0.05	1.00	1.00
0.05	0.87	0.86
0.1	0.78	0.75
0.3	0.53	0.43
0.5	0.38	0.30
1.0	0.32	0.25[1]

Notes:
1. Reference: [45] - value corrected from that published in reference [44].

Combining the above equations:

Fuel NO_X Mass emitted (kg) = 32.86 × $MP_{NITROGEN}$ × $F_{N2CONTENT}$ × M

where:
$MP_{NITROGEN}$ = Mass Percentage of Nitrogen in the fuel combusted (see note below).
$F_{N2CONTENT}$ = Adjustment factor for nitrogen content. Values are given in **Table 17**.
M = Mass of fuel combusted (in tonnes)

Note: the mass percentage of nitrogen in gaseous fuels only relates to the nitrogen bound in the combustible components in the fuel (e.g. ammonia) and does not apply to molecular nitrogen (N_2) where present as a gaseous fuel component.

Reference: [44].

14.2. GAS TURBINES

14.2.1. Natural Gas Combustion

Mass emitted (kg) = 1.53E-01 × M × NCV

where:
M = mass of fuel gas burnt (in tonnes)
NCV = net calorific value of the fuel burnt (in MJ/kg)

Reference: [19], Table 3.1-1. Factor derived from turbines operating at high loads (≥ 80%).

14.2.2. Distillate Oil Combustion

Mass emitted (kg) = 3.98E-01 × M × NCV

where:
M = mass of distillate oil burnt (in tonnes)
NCV = net calorific value of the fuel burnt (in MJ/kg)

Reference: [19], Table 3.1-1. Factor derived from turbines operating at high loads (≥ 80%).

14.3. GAS ENGINES (4 STROKE, LEAN BURN)

Mass emitted (kg) = 4.05E-01 × M × NCV

where:
M = mass of fuel gas burnt (in tonnes)
NCV = net calorific value of the fuel burnt (in MJ/kg)

Reference: [19], Table 3.2-2. Factor derived from engines operating at < 90% load.

14.4. DIESEL ENGINES (LARGE, STATIONARY)

Mass emitted (kg) = 1.45E+00 × M × NCV

where:
M = mass of diesel fuel burnt (in tonnes)
NCV = net calorific value of the fuel burnt (in MJ/kg)

Reference: [19], Table 3.4-1.

14.5. COMBUSTION OF AUXILIARY AND PILOT FUELS

Auxiliary fuels are used to support combustion in, for example, CO boilers and incinerators. Pilots are used to initiate combustion in flares.

Mass emitted (kg) = 6.22E-02 × M × NCV

where:
M = mass of auxiliary/pilot fuel burnt (in tonnes)
NCV = net calorific value of the fuel burnt (in MJ/kg)

This assumes emissions are equivalent to burning natural gas with dry combustion air in an uncontrolled furnace – see **Section 14.1**.

Reference: [44].

14.6. DESTRUCTION OF GASEOUS STREAMS

14.6.1. Flares

The following algorithms are for emissions from the combustion of the flare gas. For emissions from the combustion of the pilot gas fuel used to initiate flare combustion, use the algorithm in **Section 14.5**.

14.6.1.1. Flare Stream Details Known

If the mass and composition of the flare stream are known:

Mass emitted (kg) = 3.22E-02 × M × NCV

where:
M = mass of flare gas burnt (in tonnes)
NCV = net calorific value of the flare gas burnt (in MJ/kg)

Reference: [20], Section 4.2.1, Table 8.

14.6.1.2. Flare Stream Details Unknown

If the mass and composition are not known and a flare gas recovery system is not installed, a conservative factor based on refinery feed can be used:

Mass emitted (kg) = 5.40E-02 × Refinery Feed (in m^3)

Reference: [21], Activity 090203, Section 8, Table 2.

If a flare gas recovery system is installed it can be considered to be an emissions control device. The equation in **Section 6.1** can be used (with EFF = flare gas recovery system efficiency) to adjust the emissions estimate obtained from the algorithm above.

14.6.2. Incinerators

For all incinerator streams use the algorithms in **Section 14.1**, assuming that the 'fuel' is low joule gas and that $F_{CONTROL}$, $F_{PREHEAT}$, F_{LOAD} and F_{BURN} all have a value of 1.00

For emissions from the combustion of the auxiliary gas fuel used to support incinerator combustion, use the algorithm in **Section 14.5**.

14.7. CATALYTIC CRACKING UNIT REGENERATORS

For CCU regenerators, both with and without CO boilers:

Mass emitted (kg) = 2.04E-01 × Volume of fresh feed to unit (in m^3)

Reference: [6], Section 5.1, Table 5.1-1.

15. SULPHUR HEXAFLUORIDE (SF_6)

Emissions of sulphur hexafluoride (SF_6) may occur due to its use as a tracer gas or from leaks from high voltage electrical equipment where this gas is used as an insulator.

Emissions are assumed to equal the amount used and not recovered during test procedures and/or the mass used to top-up or refill equipment.

Mass emitted (kg) = Mass used (in kg)

16. OXIDES OF SULPHUR (SO_X)

The E-PRTR requires estimates of the total oxides of sulphur (SO_2 and SO_3) reported as SO_2.

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators and flares
- Catalytic cracking unit regenerators
- Catalytic reforming units

16.1. COMBUSTION

For all fuel combustion, the following algorithm applies:

Mass emitted (kg) = $1000 \times M \times MF_S \times SF_{MW}$

where:
M = mass of fuel burnt (in tonnes)
MF_S = mass fraction of sulphur in fuel
SF_{MW} = Molecular weight conversion from S to SO_2 = 64/32

This assumes that all the sulphur in the fuel is converted to SO_2.

For refinery oil and gaseous fuels:

Mass emitted (kg) = $2.00E+03 \times M \times MF_S$

Reference: [20], Section 4.1.1.1.

16.2. DESTRUCTION OF GASEOUS STREAMS

16.2.1. Flares

The following algorithms are for emissions from the combustion of the flare gas. For emissions from the combustion of the pilot gas fuel used to initiate flare combustion, use the algorithm in **Section 16.1**.

16.2.1.1. Flare Stream Details Known

If the mass and composition of the flare stream are known, use algorithm in **Section 16.1**, where:
M = mass of flare gas burnt (in tonnes)
MF_S = mass fraction of sulphur in flare gas

16.2.1.2. Flare Stream Details Unknown

If the mass and composition are not known, a conservative factor based on refinery feed can be used. This assumes that a flare gas recovery system is not installed:

Mass emitted (kg) = 7.70E-02 × Refinery Feed (in m^3)

Reference: [21], Activity 090203, Section 8, Table 2.

If a flare gas recovery system is installed it can be considered to be an emissions control device. The equation in **Section 6.1** can be used (with EFF = flare gas recovery system efficiency) to adjust the emissions estimate obtained from the algorithm above.

16.2.2. Incinerators

For all incinerator gas streams, including that from a sulphur plant if the gas composition is known, use the algorithm in **Section 16.1**, where:
M = mass of gas incinerated
MF_S = mass fraction of sulphur in gas incinerated

For emissions from the combustion of the auxiliary gas fuel used to support incinerator combustion, also use the algorithm in **Section 16.1**.

16.2.2.1. Sulphur Plant Tail Gas Incinerator

For a sulphur plant, if the composition of the gas stream is unknown, emissions can be determined from the sulphur balance across the plant.

Mass emitted (kg) = $[(100 - ERC_{EFF}) / ERC_{EFF}] \times PROD \times SF_{MW} \times 1000$

where:
ERC_{EFF} = recovery efficiency (in %)
PROD = sulphur production (in tonnes)
SF_{MW} = Molecular weight conversion from S to SO_2 = 64/32

Reference: [46], Section 8.13, Table 8.13-1.

16.3. CATALYTIC CRACKING UNIT REGENERATORS

For CCU regenerators, the emissions can be determined using coke sulphur content data. If these are not available, a less accurate emission factor can be used.

Where $DeSO_X$ catalyst additive is used, the abatement effect of this on the emissions should be taken into account using the algorithm in **Section 6.1** with the value of EFF being the SO_X percentage removal efficiency.

The following emission estimation algorithms are applicable both with and without CO boilers.

16.3.1. Sulphur retention on coke known

Mass emitted (kg) = 2.00E+03 × M × MF_{SFEED} × MF_{SCOKE}

where:
M = mass of feed to unit (in tonnes)
MF_{SFEED} = mass fraction of sulphur in feed
MF_{SCOKE} = mass fraction of MF_{SFEED} contained in coke

Reference: [27], Section 15.3.1.4.

16.3.2. Sulphur retention on coke not known

Mass emitted (kg) = 1.41E+00 × Volume of fresh feed to unit (in m^3)

Reference: [6], Section 5.1, Table 5.1-1.

16.4. CATALYTIC REFORMING UNITS

Mass emitted (kg) = 3.63E-03 × Volume of feed to unit (in m^3)

Reference: [14], Table 1. This reference uses data from a number of units with varying degrees of abatement equipment installed – see **Section 6.3**.

17. HYDROCHLOROFLUOROCARBONS (HCFC)

Hydrochlorofluorocarbons (HCFCs) may be used as refrigerants in refinery thermal exchange equipment.

Emissions are assumed to equal the amount used during the reporting period to top-up systems to replenish losses due to uncontrolled leakage.

Mass emitted (kg) = Mass used to top-up refrigerant systems (in kg)

Usage where the systems have been fully or partially drained and refrigerants collected for recycling or destruction should not be reported.

18. ARSENIC (As)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators
- Catalytic cracking unit regenerators
- Fluid cokers

18.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 18.**

Table 18 As Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	1.81E-03	[17] Section 1.3, Table 1.3-10
	Refinery Fuel Oil	3.98E-03	[17] Section 1.3, Table 1.3-11
	Natural Gas	9.37E-05	[17] Section 1.4, Table 1.4-4
	Refinery Fuel Gas	3.43E-04	[11], [47][1]
Gas Turbine	Distillate (gas oil)	Not detected[2]	[19] Section 3.1, Table 3.1-5
Incinerator Support Fuel or Flare Pilot Fuel	Natural Gas	9.37E-05	[17] Section 1.4, Table 1.4-4

Notes:
1. Reference [11] is base document, but reference [47] provides the same emission factors to more significant figures.
2. Compound was not detected. The emission factor stated in reference [19] is based on one half of the detection limit. For the purposes of this report the emission factor is considered to be zero as source not proven (See **Section 5.2** of this report).

18.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 18.1** with an emission factor EF_{NCV} equal to that for fuel gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 18.1**.

18.3. CATALYTIC CRACKING UNIT REGENERATORS

Mass emitted (kg) = 1.39E-05 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in CCU vents. It is for a unit with cyclone systems installed inside the regenerator vessel – see **Section 6.2.**

Reference: [20], Section 4.2.3, Tables 10 and 11.

18.4. FLUID COKERS

Mass emitted (kg) = 2.16E-03 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in fluid coker vents.

Reference: [20], Section 4.2.3, Tables 10 and 11.

19. CADMIUM (Cd)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators
- Catalytic cracking unit regenerators

19.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 19**.

Table 19 Cd Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	1.36E-03	[17] Section 1.3, Table 1.3-10
	Refinery Fuel Oil	1.20E-03	[17] Section 1.3, Table 1.3-11
	Natural Gas	5.16E-04	[17] Section 1.4, Table 1.4-4
	Refinery Fuel Gas	7.12E-04	[11], [47][1]
Gas Turbine	Distillate (gas oil)[2]	2.17E-03	[19] Section 3.1, Table 3.1-5
	Natural Gas[3]	3.31E-03	[18] SCC 20200201
	Refinery Fuel Gas[4]	2.52E-03	[11], [47][1]
Incinerator Support Fuel or Flare Pilot Fuel	Natural Gas	5.16E-04	[17] Section 1.4, Table 1.4-4

Notes:
1. Reference [11] is base document, but reference [47] provides the same emission factors to more significant figures.
2. Factor derived from turbines operating at high (≥ 80%) loads.
Factor provided in reference [19] derived using HHV of 139 MBtu/10^3 US gal.
3. Factor has an EPA quality rating of “U” (unrated).
4. Factor derived from gas turbines without duct burners.

19.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 19.1**, with an emission factor EF_{NCV} equal to that for fuel gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 19.1**.

19.3. CATALYTIC CRACKING UNIT REGENERATORS

Mass emitted (kg) = 6.25E-05 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in CCU vents. It is for a unit with cyclone systems installed inside the regenerator vessel – see **Section 6.2.**

Reference: [20], Section 4.2.3, Tables 10 and 11.

20. CHROMIUM (Cr)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators

20.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 20**.

Table 20 Cr Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	1.36E-03	[17] Section 1.3, Table 1.3-10
	Refinery Fuel Oil	1.48E-02	[11], [47][1]
	Natural Gas	6.55E-04	[17] Section 1.4, Table 1.4-4
	Refinery Fuel Gas	2.74E-03	[11], [47][1,2]
Gas Turbine	Distillate (gas oil)[3]	4.98E-03	[19] Section 3.1, Table 3.1-5
	Natural Gas[4]	6.35E-03	[18] SCC 20200201
	Refinery Fuel Gas[5]	6.26E-03	[11], [47][1,2]
Incinerator Support Fuel or Flare Pilot Fuel	Natural Gas	6.55E-04	[17] Section 1.4, Table 1.4-4

Notes:

1. Reference [11] is base document, but reference [47] provides the same emission factors to more significant figures.
2. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.
3. Factor derived from turbines operating at high (≥ 80%) loads.
   Factor provided in reference [19] derived using HHV of 139 MBtu/10^3 US gal.
4. Factor has an EPA quality rating of "U" (unrated).
5. Factor derived from gas turbines without duct burners.

20.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 20.1** with an emission factor EF_{NCV} equal to that for fuel gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 20.1**.

21. COPPER (Cu)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators
- Catalytic cracking unit regenerators
- Fluid cokers

21.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 21**.

Table 21 Cu Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	2.72E-03	[17] Section 1.3, Table 1.3-10
	Refinery Fuel Oil	1.19E-02	[11], [47][1]
	Natural Gas	3.98E-04	[17] Section 1.4, Table 1.4-4
	Refinery Fuel Gas	2.22E-03	[11], [47][1]
Gas Turbine	Natural Gas[2]	3.31E-02	[18] SCC 20200201
	Refinery Fuel Gas[3]	1.97E-02	[11], [47][1]
Incinerator Support Fuel or Flare Pilot Fuel	Natural Gas	3.98E-04	[17] Section 1.4, Table 1.4-4

Notes:
1. Reference [11] is base document, but reference [47] provides the same emission factors to more significant figures.
2. Factor has an EPA quality rating of “U” (unrated).
3. Factor derived from gas turbines without duct burners.

21.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 21.1** with an emission factor EF_{NCV} equal to that for fuel gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 21.1**.

21.3. CATALYTIC CRACKING UNIT REGENERATORS

Mass emitted (kg) = 1.39E-04 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in CCU vents. It is for a unit with cyclone systems installed inside the regenerator vessel – see **Section 6.2.**

Reference: [20], Section 4.2.3, Tables 10 and 11.

21.4. FLUID COKERS

Mass emitted (kg) = 1.50E-05 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in fluid coker vents.

Reference: [20], Section 4.2.3, Tables 10 and 11.

22. MERCURY (Hg)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators
- Catalytic cracking unit regenerators
- Fluid cokers

22.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 22**.

Table 22 Hg Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	1.36E-03	[17] Section 1.3, Table 1.3-10
	Refinery Fuel Oil	Not Detected[1]	[11], [47][2]
	Natural Gas	1.22E-04	[17] Section 1.4, Table 1.4-4
	Refinery Fuel Gas	8.60E-05	[11], [47][2,3]
Gas Turbine	Distillate (gas oil)[4]	5.43E-04	[19] Section 3.1, Table 3.1-5
	Natural Gas[5]	3.17E-03	[18] SCC 20200201
	Refinery Fuel Gas[6]	7.31E-03	[11], [47][2]
Incinerator Support Fuel or Flare Pilot Fuel	Natural Gas	1.22E-04	[17] Section 1.4, Table 1.4-4

Notes:

1. Compound was not detected. Emission factor stated in reference [11] represents the detection limit. For the purposes of this report the emission factor is considered to be zero as the source is not proven (See **Section 5.2** of this report).
2. Reference [11] is base document, but reference [47] provides the same emission factors to more significant figures.
3. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.
4. Factor derived from turbines operating at high (≥ 80%) loads.
   Factor provided in reference [19] derived using HHV of 139 MBtu/10^3 US gal.
5. Factor has an EPA quality rating of “U” (unrated).
6. Factor derived from gas turbines without duct burners

22.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 22.1** with an emission factor EF_{NCV} equal to that for fuel gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 22.1**.

22.3. CATALYTIC CRACKING UNIT REGENERATORS

Mass emitted (kg) = 6.95E-05 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in CCU vents. It is for a unit with cyclone systems installed inside the regenerator vessel – see **Section 6.2.**

Reference: [20], Section 4.2.3, Tables 10 and 11.

22.4. FLUID COKERS

Mass emitted (kg) = 3.00E-05 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in fluid coker vents.

Reference: [20], Section 4.2.3, Tables 10 and 11.

23. NICKEL (Ni)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators
- Catalytic cracking unit regenerators
- Fluid cokers

23.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 23**.

Table 23 Ni Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	1.36E-03	[17] Section 1.3, Table 1.3-10
	Refinery Fuel Oil	1,03E+00	[11], [47][1]
	Natural Gas	9.85E-04	[17] Section 1.4, Table 1.4-4
	Refinery Fuel Gas	3.60E-03	[11], [47][1,2]
Gas Turbine	Distillate (gas oil)	Not detected[3]	[19] Section 3.1, Table 3.1-5
	Natural Gas[4]	5.48E-02	[18] SCC 20200201
	Refinery Fuel Gas[5]	7.93E-02	[11], [47][1]
Incinerator Support Fuel or Flare Pilot Fuel	Natural Gas	9.85E-04	[17] Section 1.4, Table 1.4-4

Notes:

1. Reference [11] is base document, but reference [47] provides the same emission factors to more significant figures.
2. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.
3. Compound was not detected. The emission factor stated in reference [19] is based on one half of the detection limit. For the purposes of this report the emission factor is considered to be zero as the source is not proven (See **Section 5.2** of this report).
4. Factor has an EPA quality rating of "U" (unrated).
5. Factor derived from gas turbines without duct burners.

23.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 23.1** with an emission factor EF_{NCV} equal to that for fuel gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 23.1**.

23.3. CATALYTIC CRACKING UNIT REGENERATORS

Mass emitted (kg) = 6.12E-04 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in CCU vents. It is for a unit with cyclone systems installed inside the regenerator vessel – see **Section 6.2.**

Reference: [20], Section 4.2.3, Tables 10 and 11.

23.4. FLUID COKERS

Mass emitted (kg) = 5.70E-04 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in fluid coker vents.

Reference: [20], Section 4.2.3, Tables 10 and 11.

24. LEAD (Pb)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators
- Catalytic cracking unit regenerators
- Fluid cokers

24.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 24**.

Table 24 Pb Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	4.07E-03	[17] Section 1.3, Table 1.3-10
	Refinery Fuel Oil	4.56E-03	[17] Section 1.3, Table 1.3-11
	Natural Gas	2.34E-04	[17] Section 1.4, Table 1.4-4
	Refinery Fuel Gas	1.79E-03	[11], [47][1]
Gas Turbine	Distillate (gas oil)[2]	6.34E-03	[19] Section 3.1, Table 3.1-5
	Refinery Fuel Gas[3]	1.36E-02	[11], [47][1,4]
Incinerator Support Fuel or Flare Pilot Fuel	Natural Gas	2.34E-04	[17] Section 1.4, Table 1.4-4

Notes:

1. Reference [11] is base document, but reference [47] provides the same emission factors to more significant figures.
2. Factor derived from turbines operating at high (≥ 80%) loads. Factor provided in reference [19] derived using HHV of 139 MBtu/10^3 US gal.
3. Factor derived from gas turbines without duct burners.
4. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.

24.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 24.1** with an emission factor EF_{NCV} equal to that for fuel gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 24.1**.

24.3. CATALYTIC CRACKING UNIT REGENERATORS

Mass emitted (kg) = 3.20E-04 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in CCU vents. It is for a unit with cyclone systems installed inside the regenerator vessel – see **Section 6.2.**

Reference: [20], Section 4.2.3, Tables 10 and 11.

24.4. FLUID COKERS

Mass emitted (kg) = 4.50E-05 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in fluid coker vents.

Reference: [20], Section 4.2.3, Tables 10 and 11.

25. ZINC (Zn)

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators
- Catalytic cracking unit regenerators
- Fluid cokers

25.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 25**.

Table 25 Zn Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	1.81E-03	[17] Section 1.3, Table 1.3-10
	Refinery Fuel Oil	4.93E-02	[11], [47][1]
	Natural Gas	1.36E-02	[17] Section 1.4, Table 1.4-4
	Refinery Fuel Gas[2]	2.55E-02	[11]
Gas Turbine	Refinery Fuel Gas[3]	2.38E+00	[11], [47][1]
Incinerator Support Fuel or Flare Pilot Fuel	Natural Gas	1.36E-02	[17] Section 1.4, Table 1.4-4

Notes:

1. Reference [11] is base document, but reference [47] provides the same emission factors to more significant figures.
2. Factor represents median value as the ratio of mean to median value > 10. See **Section 5.3**.
3. Factor derived from gas turbines without duct burners.

25.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 25.1** with an emission factor EF_{NCV} equal to that for fuel gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 25.1**.

25.3. CATALYTIC CRACKING UNIT REGENERATORS

Mass emitted (kg) = 1.18E-04 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in CCU vents. It is for a unit with cyclone systems installed inside the regenerator vessel – see **Section 6.2.**

Reference: [20], Section 4.2.3, Tables 10 and 11.

25.4. FLUID COKERS

Mass emitted (kg) = 4.50E-05 × Volume of fresh feed to unit (in m^3)

This algorithm has been derived from speciation data for total particulate matter in fluid coker vents.

Reference: [20], Section 4.2.3, Tables 10 and 11.

26. DIOXINS AND FURANS (PCDD AND PCDF)

Dioxins and furans are only produced during combustion processes under specific conditions and where chlorine is present. Estimation methods are provided for emissions from:

- Combustion of fuel oil
- Catalytic reforming units

The emission factors for each of the 17 isomers of PCDD and PCDF have been multiplied by the Toxic Equivalence Factor (TEF) in **Table 26** to give the emission factor in g I-TEQ (Toxic Equivalent to the most toxic isomer 2,3,7,8-CDD).

26.1. COMBUSTION OF FUEL OIL

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g I-TEQ/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 26**

Table 26 Emission Factors for PCDD and PCDF from Fuel Oil Combustion

ISOMER	I-TEF	Emission Factor lb/MMBtu (HHV)	Emission Factor g I-TEQ/GJ (NCV)
Dioxin 4D 2378	1	Not detected	0[1]
Dioxin 5D 12378	0.5	Not detected	0[1]
Dioxin 6D 123478	0.1	Not detected	0[1]
Dioxin 6D 123678	0.1	2.50E-12	1.13E-10
Dioxin 6D 123789	0.1	2.50E-12	1.13E-10
Dioxin 7D 1234678	0.01	2.12E-11	9.59E-11
Dioxin 8D	0.001	5.10E-10	2.31E-10
Furan 4F 2378	0.1	5.54E-12	2.51E-10
Furan 5F 12378	0.05	Not detected	0[1]
Furan 5F 23478	0.5	Not detected	0[1]
Furan 6F 123478	0.1	2.48E-12	1.12E-10
Furan 6F 123678	0.1	1.86E-12	8.42E-11
Furan 6F 123789	0.1	Not detected	0[1]
Furan 6F 234678	0.1	3.74E-12	1.69E-10
Furan 7F 1234678	0.01	9.79E-12	4.43E-11
Furan 7F 1234789	0.01	Not detected	0[1]
Furan 8F	0.001	4.86E-11	2.20E-11
TOTAL			**1.24E-09**

Notes:

1. Compound was not detected. The emission factor stated in reference [11] is based on the detection limit. For the purposes of this report, the emission factor is considered to be zero as the source was not proven (See **Section 5.2** of this report).

Reference: [11].

26.2. CATALYTIC REFORMING UNIT REGENERATORS

There are very few data available for the emissions from these units. The US EPA [48] provides emission factors derived from tests on two units with different modes of catalyst regeneration – continuous and semi-regenerative.

Continuous Regeneration Mode

Mass emitted (kg I-TEQ) = 1.91E-11 × Volume of feed to unit (in m^3)

Semi-Regenerative Mode

Mass emitted (kg I-TEQ) = 6.35E-15 × Volume of feed to unit (in m^3)

Reference: [48], Section 5.4.

27. BENZENE (C_6H_6)

Benzene is emitted as a constituent of VOC evaporative or leakage (fugitive) emissions and from the combustion of flare streams, fuels e.g. in boilers and furnaces, and coke in FCCU regenerators and cokers.

Combustion emissions are typically negligible compared to fugitive emissions.

Fugitive emissions are diffuse in a large facility like a refinery. Although those from pressurised equipment can be determined from speciation data for each stream in the refinery and leak monitoring surveys, this requires considerable effort and does not cover emissions from systems such as tanks, drains, oil-water separators, etc. One measurement technique is to monitor occasionally the composition of NMVOCs in the ambient air at the fence line to determine the average benzene mass fraction.

Where this technique is not undertaken, an estimation method for fugitives is provided using a default value for the mass fraction of benzene. For completeness, algorithms are also provided for the minor sources.

27.1. SPECIATED FENCELINE NMVOC DATA AVAILABLE

In general, VOC fugitive sources are numerous but individually small e.g. from valves, drain systems, etc. To determine the benzene emitted by a facility, one approach is to take occasional ambient air samples at regular points around the boundary fence and establish the average benzene mass fraction of the NMVOCs measured. Care must be taken in the positioning of the samplers to ensure that they are not located near to local emission sources that may skew the results. Full details of a methodology are given in reference [49].

The mass of benzene emitted by the facility is then calculated from:

Mass emitted (kg) = $SUMCALC_{NMVOC} \times MF_{BENZENE}$

where:
$SUMCALC_{NMVOC}$ = sum of the individual calculated masses of NMVOCs emitted (in kg) within the facility, as per **Section 13**.
$MF_{BENZENE}$ = Mass fraction of benzene (from fence line monitoring survey).

27.2. NO SPECIATED FENCELINE NMVOC DATA AVAILABLE

Where fence line monitoring is not undertaken, a value of $MF_{BENZENE}$ = 1.72% mass can be used.

Mass emitted (kg) = $1.72E\text{-}02 \times SUMCALC_{NMVOC}$

where:
$SUMCALC_{NMVOC}$ = sum of the individual calculated masses of NMVOCs emitted (in kg) within the facility, as per **Section 13**.

Reference: [27], Section 15.5.3, Table 15-7.

27.3. ESTIMATION BY SOURCE

For completeness, algorithms are provided below for combustion sources and uncontrolled blowdown systems. The emission from the following combustion sources are typically negligible compared to fugitive sources:

- Combustion of fuels
- Destruction of gaseous streams in flares
- Catalytic cracking unit regenerators
- Fluid cokers

If some or all of the following algorithms are used, then the emissions are:

Mass emitted (kg) = Sum of emissions using algorithms below + Sum of emissions from all other sources using algorithms in Section 27.1 or 27.2

27.3.1. Combustion of Fuels

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 27**.

Table 27 Benzene Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Refinery Fuel Oil	6.47E-04	[17] Section 1.3, Table 1.3-9
	Natural Gas	9.84E-04	[17] Section 1.3, Table 1.3-9
	Refinery Fuel Gas	2.13E-03	[11][1,2]
Gas Turbine[3]	Distillate (Gas Oil)[4]	2.49E-02	[19] Section 3.1, Table 3.1-4
	Natural Gas	5.73E-03	[19] Section 3.1, Table 3.1-3
Gas Engine 4-stroke, Lean Burn	Natural Gas	2.10E-01	[19] Section 3.2, Table 3.2-2
	Refinery Fuel Gas	6.21E-01	[11], [47][5]
Diesel Engine Large, Stationary	Distillate (Gas Oil)	3.22E-01	[11], [47][5]
Incinerator Support Fuel or Flare Pilot Fuel	Natural Gas	9.84E-04	[17] Section 1.3, Table 1.3-9

Notes:
1. Factor represents the median value as the ratio of mean to median value > 10. See **Section 5.3**.

2. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.
3. Factor derived from turbines operating at high (≥ 80%) loads.
4. Factor provided in reference [19] derived using HHV of 139 MBtu/10^3 US gal.
5. Reference [11] is base document, but reference [47] provides the same emission factors to more significant figures

27.3.2. Destruction of Flare Streams

The following algorithms are for emissions from the combustion of the flare gas. For emissions from the combustion of the pilot gas fuel used to initiate flare combustion, use the algorithm in **Section 27.3.1**.

27.3.2.1. Flare Stream Details Known

If the mass and composition of the flare stream are known:

Mass emitted (kg) = 5.00E-00 × M × MF_{BENZ}

where:
M = total mass of gas flared (in tonnes)
MF_{BENZ}= mass fraction of benzene in gas flared

This algorithm assumes that 0.5% of the hydrocarbons remain unburned in “well designed and operated flares, such as in refineries”.

Reference: [15], Section 4.4.

27.3.2.2. Flare Stream Details Unknown

If the mass and composition are not known and a flare gas recovery system is not installed, a conservative factor based on refinery feed can be used:

Mass emitted (kg) = 1.66E-06 × Refinery Feed (in m^3)

Reference: Derived from [21], Activity 090203, Section 8, Table 2, and [20], Section 4.22, Table 9.

If a flare gas recovery system is installed it can be considered to be an emissions control device. The equation in **Section 6.1** can be used (with EFF = flare gas recovery system efficiency) to adjust the emissions estimate obtained from the algorithm above.

27.3.3. Catalytic Cracking Unit Regenerators

27.3.3.1. Full Burn Regeneration

Emissions of NMVOCs, and hence benzene, are considered negligible.

27.3.3.2. Partial Burn with CO Boiler

Emissions of NMVOCs, and hence benzene, are considered negligible.

Reference: [6], Table 5.1-1.

27.3.3.3. Partial Burn without CO Boiler

If the off-gas is not fed to a CO boiler, or it is not in operation:

Mass emitted (in kg) = 8.04E-04 × Mass of coke burnt (in tonnes)

Reference: [13], Table 1. This reference provides data on the number of data points both above and below the limit of detection. The emission factor is a weighted value using both sets of data – see **Section 5.2** of this report.

27.3.4. Fluid Cokers

27.3.4.1. Emissions Controlled with CO or Fired Waste Heat Boiler

Emissions of NMVOCs, and hence benzene, are considered negligible.

Reference: [6], Table 5.1-1.

27.3.4.2. Non-Controlled Emissions

If the off-gas is not fed to a CO or fired waste heat boiler, or it is not in operation:

Mass emitted (in kg) = 1.75E-04 × Feed to unit (in m^3)

This assumes that benzene makes up 0.38% by mass of the VOCs in the vented gas.

Reference: [20], Section 4.2.1, Table 8 and Section 4.2.2, Table 9.

27.3.5. Uncontrolled Blowdown System

The gaseous emissions from blowdown systems in EU refineries are recovered and/or flared.

If these controls are not operational and all of the emissions are released to atmosphere, the benzene emissions can be conservatively estimated using the factor provided in reference [6], Table 5.1-1 to determine total hydrocarbon (THC) emissions and assuming that benzene makes up 0.38% by mass of the THCs in the blowdown gas (reference [20], Section 4.2.2, Table 9).

28. POLYCYCLIC AROMATIC HYDROCARBONS (PAH)

The E-PRTR requires the total emissions of the four PAHs listed below:

- Benzo(a)pyrene
- Benzo(b)fluoranthene
- Benzo(k)fluoranthene
- Indeno(1,2,3-cd)pyrene

Estimation methods are provided for emissions from:

- Combustion of fuels
- Destruction of gaseous streams in incinerators
- Catalytic cracking unit regenerators

Speciated values are provided for the four individual PAHs in addition to the summation of the emission factors.

Emission factors for total PAH emissions are available for the combustion of distillate fuel in gas turbines (reference [19], Section 3.1, Table 3.1-15) and for flare gas (reference [20], Section 4.2.2, Table 9). These factors are not reproduced in this report as E-PRTR requires the emissions to be reported of only a limited number of the total PAH compounds.

28.1. COMBUSTION OF FUELS

Mass emitted (kg) = $(EF_{NCV} \times M \times NCV) / 1000$

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Sections 28.1.1** to **28.1.5**.

28.1.1. Refinery Fuel Oil Combustion in Boilers and Furnaces

Table 28 PAH Emission Factors for Fuel Oil Combustion

PAH	EF_{NCV} g/GJ
Benzo(a)pyrene	0[1]
Benzo(b)fluoranthene	3.670E-06[2]
Benzo(k)fluoranthene	0[1]
Indeno(1,2,3-cd)pyrene	0[1]
Total	3.67E-06

Notes:

1. Compound was not detected. The emission factor stated in reference [11] represents the detection limit. The emission factor is thus considered to be zero as the source is not proven (See **Section 5.2** of this report).

2. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.

For CO boilers and fired waste heat boilers, the algorithm should only be applied to the support fuel fired.

Reference: [11], [47].

28.1.2. Gas Combustion in Boilers and Furnaces

28.1.2.1. Natural Gas

The emission factors for all four of the PAHs stated in reference [17], Table 1.4-3 represent detection limit values. The emission factors are thus considered to be zero as the source is not proven (See **Section 5.2** of this report).

28.1.2.2. Refinery Fuel Gas

Table 29 PAH Emission Factors for Refinery Fuel Gas Combustion in Boilers and Furnaces

PAH	**EF_{NCV} g/GJ**
Benzo(a)pyrene	6.688E-07[1,2]
Benzo(b)fluoranthene	1.137E-06[1,2]
Benzo(k)fluoranthene	6.306E-07[1,2]
Indeno(1,2,3-cd)pyrene	6.306E-07[1,2]
Total	3.07E-06

Notes:
1. Ratio of mean to median value > 10. Median value used. See **Section 5.3**.
2. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.

For CO boilers and fired waste heat boilers, the algorithm should only be applied to the support fuel fired.

Reference: [11], [47].

28.1.3. Gas Combustion in Gas Turbines

Table 30 PAH Emission Factors for Gas Combustion in Gas Turbines

PAH	**EF_{NCV} g/GJ**[1]
Benzo(a)pyrene	0[2]
Benzo(b)fluoranthene	1.576E-06[3]
Benzo(k)fluoranthene	1.113E-06[3]
Indeno(1,2,3-cd)pyrene	8.360E-07[3]
Total	3.53E-06

Notes:

1. Emission factors for gas turbine without duct burners.
2. No data available.
3. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.

Reference: [11], [47].

28.1.4. Gas Combustion in Gas Engines

Table 31 PAH Emission Factors for Gas Combustion in Gas Engines

PAH	**EF_{NCV} g/GJ**[1]
Benzo(a)pyrene	1.615E-05[2]
Benzo(b)fluoranthene	1.486E-04[2]
Benzo(k)fluoranthene	2.408E-04[2]
Indeno(1,2,3-cd)pyrene	5.446E-05
Total	4.60E-04

Notes:

1. Emission factors for 4-stroke, lean-burn gas engine.
2. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.

Reference: [11], [47].

28.1.5. Distillate Oil Combustion in Diesel Engines

Table 32 PAH Emission Factors for Distillate Oil Combustion in Diesel Engines

PAH	**EF_{NCV} g/GJ**[1]
Benzo(a)pyrene	1.127E-04[2]
Benzo(b)fluoranthene	4.888E-04[2]
Benzo(k)fluoranthene	9.640E-05[2]
Indeno(1,2,3-cd)pyrene	1.815E-04[2]
Total	8.79E-04

Notes:
1. Emission factors for large stationary engine with stack gas oxygen concentration < 13%.
2. The detect ratio reported in [11] is < 1.0. This emission factor is a weighted value using the value of the detect ratio – see **Section 5.2** of this report.

Reference: [11], [47].

28.1.6. Incinerator Support Fuel and Flare Pilot Fuel

Use values of EF_{NCV} provided in **Section 28.1.2**.

28.2. DESTRUCTION OF GASEOUS STREAMS IN INCINERATORS

For all incinerator gas streams, use the algorithm in **Section 28.1**, with values of EF_{NCV} provided in **Section 28.1.2.2**.

28.3. CATALYTIC CRACKING UNIT REGENERATORS

Mass emitted (kg) = EF_{FCC} × Mass of coke burned (in tonnes)

where:
EF_{FCC} = emission factor from **Table 33**

Table 33 PAH Emission Factors for CCU Regenerators

PAH	**EF_{FCC}**
Benzo(a)pyrene	7.072E-07
Benzo(b)fluoranthene	1.223E-06
Benzo(k)fluoranthene	8.212E-07
Indeno(1,2,3-cd)pyrene	6.238E-07
Total	3.38E-06

Reference: [13], Table 1. This reference provides data on the number of data points both above and below the limit of detection. The emission factor is a weighted value using both sets of data – see **Section 5.2** of this report.

29. CHLORINE AND INORGANIC CHLORINE COMPOUNDS

The E-PRTR requires estimates of the emissions of chlorine and inorganic chlorine compounds reported as HCl.

The major source of these pollutants is the catalytic reforming unit.

29.1. CATALYTIC REFORMING UNITS

The source of these compounds is the reactivation of the catalyst in the catalytic reforming unit. The catalyst is reactivated, following the burning off of coke deposits, using chlorine, chlorinated compounds or a chlorinated solvent. The emissions can be abated, for example using a caustic or water wash system, chloride trap or driers where HCl is present in water vapour.

A review of data from units without flue gas abatement systems installed indicate that for very high throughput units the emissions may be greater than the E-PRTR reporting threshold of 10 000 kg/year. For units with abatement systems the emissions were below the threshold value.

There are emission factors related to reformer feed rate for both chlorine and HCl available in reference [14], Table 1. This reference uses combined data from reformer units both with and without flue gas abatement systems installed. Due to the corresponding very wide scatter of emissions data, the emission factor for HCl has a variance between the median and average values of four orders of magnitude.

It is not possible, therefore, to provide reliable emission factors for uncontrolled emissions from the reformer catalyst reactivation process.

The uncontrolled emissions could be estimated from knowledge of the mass of chlorine or chlorinated compound injected, the efficiency of the reactivation process and any conversion of the compound that takes place during the activation process.

For reporting purposes, the calculated mass emitted needs to be converted to equivalent mass of HCl. This is obtained by multiplying the mass of chlorinated compound emitted by the ratio of the molecular weight of HCl to the molecular weight of the compound.

30. PARTICULATE MATTER WITH DIAMETER <10 µm (PM_{10})

Estimation methods are provided for emissions of PM_{10} due to:

- Combustion of fuels
- Destruction of gaseous streams in incinerators and flares
- Catalytic cracking unit regenerators
- Fluid cokers

PM_{10} is defined by the UNECE Task Force on Emission Inventories and Projections as particulate matter which is measured after passing through a size selective inlet with a 50% efficiency cut-off at 10 µm aerodynamic diameter. Emission factors derived from US EPA reference sources are for 'filterable' particulate matter i.e. collected on or prior to a filter of an EPA Method 5 (or equivalent) sampling train.

30.1. COMBUSTION OF FUELS

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table 34**.

Table 34 PM_{10} Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces < 10 MW (for CO Boilers and Fired Waste Heat Boilers only applies to the support fuel firing)	Distillate (gas oil)	3.49E+00	[17] Section 1.3, Table 1.3-7
	Refinery Fuel Oil	Alg. A - see below	[17] Section 1.3, Table 1.3-7
	LPG[1]	9.89E-01	[17] Section 1.5, Table 1.5-1
	Natural Gas	8.90E-01	[17] Section 1.4, Table 1.4-2
Boilers and Furnaces 10 MW to 100 MW	Distillate (gas oil)	3.23E+00	[17] Section 1.3, Table 1.3-6
	Refinery Fuel Oil	Alg. B - see below	[17] Section 1.3, Table 1.3-5
	LPG[1]	9.89E-01	[17] Section 1.5, Table 1.5-1
	Natural Gas	8.90E-01	[17] Section 1.4, Table 1.4-2

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Boilers and Furnaces > 100 MW	Distillate (gas oil)	3.23E+00	[18] SCC 10100501
	Refinery Fuel Oil	Alg. C - see below	[17] Section 1.3, Table 1.3-4
	LPG[2]	7.84E-01	[18] SCC 10101002
	Natural Gas	8.90E-01	[17] Section 1.4, Table 1.4-2
Gas Turbine[3]	Distillate (gas oil)[4]	1.95E+00	[19] Section 3.1, Table 3.1-2a
	Natural Gas	9.08E-01	[19] Section 3.1, Table 3.1-2a
Gas Engine 4-stroke, Lean Burn	Natural Gas	3.68E-02	[19] Section 3.2, Table 3.2-2
Diesel Engine Large, Stationary	Diesel Fuel	2.24E+01	[19] Section 3.4, Table 3.4-2
Incinerator Support Fuel or Flare Pilot Fuel	LPG[1]	9.89E-01	[17] Section 1.5, Table 1.5-1
	Natural Gas	8.90E-01	[17] Section 1.4 Table 1.4-2

Notes:
1. Factor is for both butane and propane combustion
2. Factor is for propane combustion
3. Factors based on combustion turbines using water-steam injection.
4. Factor provided in reference [19] derived using HHV of 139 MBtu/10^3 US gal.

Algorithms for refinery fuel oil

A. $EF_{NCV} = (17.47 \times MASS\%S) + 5.772$

B. $EF_{NCV} = (24.229 \times MASS\%S) + 8.004$

C. $EF_{NCV} = (19.937 \times MASS\%S) + 6.586$

where:

MASS%S = Percentage mass of sulphur in fuel oil (%)

(i.e. if the fuel contains 1.2% sulphur, then MASS%S = 1.2)

30.1.1. Other Fuels

In the absence of specific emission factors for other gaseous fuels (e.g. refinery fuel gas, low joule gas) it is recommended to use the value of EF_{NCV} for natural gas from **Table 34**.

30.2. DESTRUCTION OF GASEOUS STREAMS

30.2.1. Flares

For a non-smoking flare, the emissions of PM_{10} can be assumed to be negligible.

Reference: [20], Section 4.2.1, Table 8.

30.2.2. Incinerators

For all incinerator gas streams, use the algorithm in **Section 30.1** with an emission factor EF_{NCV} equal to that for natural gas combustion in a furnace.

For emissions from the combustion of the auxiliary fuel used to support incineration, also use the algorithm in **Section 30.1**.

30.3. CATALYTIC CRACKING UNIT REGENERATORS

Mass emitted (in kg) = 5.49E-01 × Feed to unit (in m^3)

Reference: [20], Section 4.2.1, Table 8.

This algorithm is for a unit with cyclone systems installed inside the regenerator vessel – see **Section 6.2.**

30.4. FLUID COKERS

Mass emitted (in kg) = 7.65E-01 × Feed to unit (in m^3)

Reference: [20], Section 4.2.1, Table 8.

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APPENDIX 1 E-PRTR AIR POLLUTANTS

Table A1.1 lists the air pollutants that must be reported under the E-PRTR Regulation if annual emissions exceed the threshold values shown. It indicates those pollutants on the sector specific indicative lists in the EU Guidance Document [4] which are considered “likely” to be emitted by refineries and combustion installations (> 50 MW). It also shows those pollutants which have been estimated by at least one refinery to exceed the E-PRTR reporting threshold.

Table A1.1 List of E-PRTR Air Pollutants

POLLUTANT	REPORTING THRESHOLD kg/year	POLLUTANT ON INDICATIVE LIST Ref [4], Appendix 5		POLLUTANTS ESTIMATED BY OIL INDUSTRY THAT MAY EXCEED PRTR THRESHOLDS
		Mineral Oil and Gas Refineries	Combustion Installations (> 50 MW)	
Methane (CH_4)	100 000	X	X	X
Carbon monoxide (CO)	500 000	X	X	X
Carbon dioxide (CO_2)	100 000 000	X	X	X
Hydrofluorocarbons (HFCs)	100	X	X	X
Nitrous oxide (N_2O)	10 000	X	X	X
Ammonia (NH_3)	10 000	X	X	X
Non-methane volatile organic compounds (NMVOCs)	100,000	X	X	X
Nitrogen oxides (NO_X)	100 000	X	X	X
Perfluorocarbons (PFCs)	100	-	-	-
Sulphur hexafluoride (SF_6)	50	-	X	X
Sulphur oxides (SO_X)	150 000	X	X	X
Hydrochlorofluorocarbons (HCFCs)	1	X	X	X
Chlorofluorocarbons (CFCs)	1	-	-	-[1]
Halons	1	-	-	-[1]
Arsenic + compounds	20	X	X	X
Cadmium + compounds	10	X	X	X
Chromium + compounds	100	X	X	X
Copper + compounds	100	X	X	X
Mercury + compounds	10	X	X	X
Nickel + compounds	50	X	X	X
Lead + compounds	200	X	X	X
Zinc + compounds	200	X	X	X

POLLUTANT	REPORTING THRESHOLD kg/year	POLLUTANT ON INDICATIVE LIST Ref [4], Appendix 5		POLLUTANTS ESTIMATED BY OIL INDUSTRY THAT MAY EXCEED PRTR THRESHOLDS
		Mineral Oil and Gas Refineries	Combustion Installations (> 50 MW)	
Aldrin	1	-	-	-
Chlordane	1	-	-	-
Chlordecone	1	-	-	-
DDT	1	-	-	-
1,2-dichloroethane	1000	-	-	-
Dichloromethane	1000	-	-	-
Dieldrin	1	-	-	-
Endrin	1	-	-	-
Heptachlor	1	-	-	-
Hexachlorobenzene	10	-	-	-
1,2,3,4,5,6-hexachlorocyclohexane	10			
Lindane	1	-	-	-
Mirex	1	-	-	-
PCDD + PCDF (dioxins and furans) (as TEQ)	0.0001	-	X	-
Pentachlorobenzene	1	-	-	-
Pentachlorophenol	10	-	-	-
Polychlorinated biphenyls (PCBs)	0.1	-	-	-
Tetrachloroethylene	2000	-	-	-
Tetrachloromethane	100	-	-	-
Trichlorobenzenes	10	-	-	-
1,1,1-trichloroethane	100	-	-	-
1,1,2,2-tetrachloroethane	50	-	-	-
Trichloroethylene	2000	-	X [2]	-
Trichloromethane	500	-	-	-
Toxaphene	1	-	-	-
Vinyl chloride	1000	-	-	-
Anthracene	50	-	-	- [3]
Benzene	1000	X	X	X
Ethylene oxide	1000	-	-	-
Naphthalene	100	-	-	- [3]

POLLUTANT	REPORTING THRESHOLD kg/year	POLLUTANT ON INDICATIVE LIST Ref [4], Appendix 5		POLLUTANTS ESTIMATED BY OIL INDUSTRY THAT MAY EXCEED PRTR THRESHOLDS
		Mineral Oil and Gas Refineries	Combustion Installations (> 50 MW)	
Di-(2-ethyly hexyl) phthalate	10	-	-	-
Polycyclic aromatic hydrocarbons (PAHs) [4]	50	X	X	X
Chlorine + inorganic compounds (as HCl)	10 000	X	X	X
Asbestos	1	-	-	-
Fluorine + inorganic compounds (as HF)	5000	-	-	-
Hydrogen cyanide (HCN)	200	-	-	-
Particulate matter < 10 micron diameter (PM_{10})	50 000	X	X	X
Hexabromobiphenyl	0.1	-	-	-
TOTALS of 60 E-PRTR air pollutants		*22*	*25*	*23*

Notes:

1. These halocarbons have been banned under EU Regulations [50] and would not be used to top-up existing equipment.
2. Trichloroethylene is not a product of combustion. The inclusion of this pollutant in the indicative sector specific list of air pollutants for thermal power stations and other combustion installations in reference [4] appears to be due to an anomaly in the EPER database.
3. The possible magnitude of emissions of anthracene and naphthalene are reviewed in **Appendix 3**.
4. Benzo(a)pyrene, benzo(b)fluoranthene, benzo(k)fluoranthene and indeno(1,2,3-cd)pyrene.

APPENDIX 2 UPDATES IN EMISSION ALGORITHMS AND FACTORS

The following changes in emission algorithms and factors have been made from the predecessor CONCAWE report No. 3/07 [9].

Carbon Monoxide

Updated emission factors:
- LPG combustion in boilers and furnaces rated < 10 MW and between 10 and 100 MW.

Carbon Dioxide

Updated oxidation factor:
- All fuel combustion.

New algorithms:
- Flare gas combustion where stream composition is unknown.
- Hydrogen plant where composition of feed is known.

Revised algorithm:
- Hydrogen plant where composition of feed is unknown.

Non-Methane Volatile Organic Compounds

New emission factors
- for optical gas imaging systems used for detection of leaks from pressurised components.

Updated emission factors:
- LPG combustion in boilers and furnaces rated < 10 MW and between 10 and 100 MW.
- fugitive emissions from pressurised components where component counts are not available.
- loading of marine tankers and barges.

New algorithms:
- emissions from pressurised components using optical gas imaging.
- emissions from uncovered gravity separators.

References to new methodologies:
- emissions from waste water treatment systems.
- emissions from internal floating roof tanks with vents that can be closed.
- emissions from tank cleaning.

Nitrogen Oxides

Updated emission factors:
- adjustment factor for amount of hydrogen in the fuel.

Oxides of Sulphur

New algorithm:
- catalytic cracking unit regenerators where the sulphur content in the coke is known.

Arsenic

Updated emission factor:
- natural gas combustion in all sizes of boilers and furnaces.

Cadmium

Updated emission factors:
- natural gas combustion in all sizes of boilers and furnaces.
- natural gas combustion in gas turbines.

Chromium

Updated emission factors:
- natural gas combustion in all sizes of boilers and furnaces.
- natural gas combustion in gas turbines.

Copper

Updated emission factors:
- natural gas combustion in all sizes of boilers and furnaces.
- natural gas combustion in gas turbines.

Mercury

Updated emission factors:
- natural gas combustion in all sizes of boilers and furnaces.
- natural gas combustion in gas turbines.

Nickel

Updated emission factors:
- natural gas combustion in all sizes of boilers and furnaces.
- natural gas combustion in gas turbines.

Lead

Updated emission factor:
- natural gas combustion in all sizes of boilers and furnaces.

Amended emission factor (deleted):
- natural gas combustion in gas turbines.

Zinc

Updated emission factor:
- natural gas combustion in all sizes of boilers and furnaces.

Amended emission factor (deleted):
- natural gas combustion in gas turbines.

Benzene

Updated emission factors:
- natural gas combustion in all sizes of boilers and furnaces.
- natural gas combustion in gas engines.
- catalytic cracking unit regenerators: partial burn without CO boiler.

PAHs

Updated emission factors:
- natural gas combustion in all sizes of boilers and furnaces.
- catalytic cracking unit regenerators.

Particulate Matter

New emission factors:
- LPG combustion in all sizes of boilers and furnaces.

Anthracene (Appendix 3)

Updated emission factors:
- catalytic cracking unit regenerators.

Naphthalene (Appendix 3)

Updated emission factors:
- catalytic cracking unit regenerators.

APPENDIX 3 ANTHRACENE AND NAPHTHALENE

Anthracene and naphthalene are pollutants known to be emitted by refineries, but neither is included on the sector specific indicative lists in the EU E-PRTR Guidance [4]. Emission estimation methods for these two pollutants are provided in this Appendix. It is demonstrated that emissions of neither pollutant are likely to exceed their respective E-PRTR reporting threshold, even at the largest of refineries.

A3.1 ANTHRACENE

Estimation methods are provided for emissions from:

- Combustion of fuels
- Fluidised catalytic cracking units

A3.1.1 Combustion of Fuels

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table A3.1**.

Reference: [11].

Table A3.1 Anthracene Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Furnaces and Boilers	Refinery Fuel Oil	9.37E-07	[11], [47][1]
	Gas	2.26E-06	[11], [47][1]
Gas Turbine[2]	Gas	1.64E-05	[11], [47][1]
Gas Engine 4-Stroke, Lean-Burn	Refinery Fuel Gas	1.17E-04	[11], [47][1]
Diesel Engine Large, Stationary[3]	Distillate (Gas Oil)	5.43E-04	[11], [47][1]

Notes:

1. Reference [11] is base document, but reference [47] provides emission factors to more significant figures.
2. Factor derived from gas turbines without duct burners.
3. Factor for stack oxygen concentration < 13%

A3.1.2 Catalytic Cracking Unit Regenerator

Mass emitted (kg) = 3.06E-06 × Mass of coke burned (in tonnes)

Reference: [13], Table 1. This reference provides data on the number of data points both above and below the limit of detection. The emission factor is a weighted value using both sets of data – see **Section 5.2** of this report.

A3.1.3 Emissions from a Very Large Refinery

To establish if anthracene could be emitted in excess of the E-PRTR reporting threshold, emissions have been calculated for a very large refinery. A survey by CONCAWE identified that the most fuel consumed at a European refinery was 8.4E+07 GJ/year, of which 3.6E+07 GJ was due to fuel oil use. The same refinery has a FCCU with a capacity of 2.9E+06 m^3/year, with a resultant coke burn of about 140 000 t/year.

- Fuel oil combusted = 3.6E+07 GJ/year
- Fuel gas combusted = 4.8E+07 GJ/year
- FCCU coke combusted = 1.4E+05 tonnes/year

The emissions from this very large refinery would be:

Emissions from oil and gas combustion
= [(9.37E-07 × 3.6E+07) + (2.26E-06 × 4.8E+07)] × 1.0E-03 = 1.42E-01 kg
Emissions from coke burn = 3.06E-06 × 1.4E+05 = 4.28E-01 kg

Total emissions = 0.57 kg/year

These emissions are significantly less than the E-PRTR reporting threshold of 50 kg/year.

A3.2 NAPHTHALENE

Estimation methods are provided for emissions from:

- Combustion of fuels
- Fluidised catalytic cracking units

A3.2.1 Combustion of Fuels

Mass emitted (kg) = (EF_{NCV} × M × NCV) / 1000

where:
EF_{NCV} = Emission factor (in g/GJ)
M = mass of fuel combusted (in tonnes)
NCV = net calorific value of the fuel combusted (in MJ/kg)

Values for the emission factor EF_{NCV} are provided in **Table A3.2**.

Reference: [11].

Table A3.2 Naphthalene Emission Factors for Combustion Sources

SOURCE	FUEL	EF_{NCV} g/GJ	REF
Furnaces and Boilers	Refinery Fuel Oil	1.83E-04	[11], [47][1]
	Gas	1.86E-04	[11], [47][1]
Gas Turbine	Distillate (Gas Oil)[2]	1.58E-02	[19], Section 3.1, Table 3.1-4
	Gas[3]	3.48E-04	[11], [47][1]
Gas Engine 4-Stroke, Lean-Burn	Refinery Fuel Gas	5.54E-02	[11], [47][1]
Diesel Engine Large, Stationary[4]	Distillate (Gas Oil)	5.75E-02	[11], [47][1]

Notes:
1. Reference [11] is base document, but reference [47] provides emission factors to more significant figures.
2. Factor derived from turbines operating at high (≥ 80%) loads.
   Factor provided in reference [19] derived using HHV of 139 MBtu/10^3 US gal.
3. Factor derived from gas turbines without duct burners.
4. Factor for stack oxygen concentration < 13%

A3.2.2 Catalytic Cracking Unit Regenerator

Mass emitted (kg) = 5.59E-05 × Mass of coke burned (in tonnes)

Reference: [13]], Table 1. This reference provides data on the number of data points both above and below the limit of detection. The emission factor is a weighted value using both sets of data – see **Section 5.2** of this report.

A3.2.3 Emissions from a Very Large Refinery

To establish if naphthalene could be emitted in excess of the E-PRTR reporting threshold, emissions have been estimated for the very large refinery described in **Section A3.1.3**.

- Fuel oil combusted = 3.6E+07 GJ/year
- Fuel gas combusted = 4.8E+07 GJ/year
- FCCU coke combusted = 1.4E+05 tonnes/year

The emissions from this very large refinery would be:

Emissions from combustion
= [(1.83E-04 × 3.6E+07) + (1.86E-04 × 4.8E+07)] × 1.0E-03 = 1.55E+01 kg
Emissions from FCCU coke burn = 5.59E-05 × 1.4E+05 = 7.83E+00 kg

Total emissions = 23.3 kg/year

These emissions are less than the E-PRTR reporting threshold of 100 kg/year.

APPENDIX 4 NMVOC EMISSIONS FROM GASOLINE MARKETING FACILITIES

Neither marketing distribution terminals (i.e. road tanker gasoline loading facilities which are not located on a refinery site) nor service stations are regulated under the terms of the IPPC Directive [1] and hence are not required to submit E-PRTR reports.

Algorithms are provided in this Appendix, however, as emission estimates for distribution terminals and service stations may be made by oil companies for their own environmental reporting purposes.

A 4.1 DISTRIBUTION TERMINALS

The major sources of emissions at terminals are the storage and loading of gasolines. As there is negligible methane in refined transport fuels, it can be assumed that there are no emissions of CH_4.

A 4.1.1 Storage Tanks

Use the methodologies provided in **Section 13.9**.

A 4.1.2 Loading of Mobile Containers

Use the methodologies provided in **Section 13.8**.

A 4.1.3 Fugitive Emissions from Components

Emissions can occur due to leakage past seals, flanges, etc., on components installed in product pipelines and loading systems e.g. pump seals, connectors.

The emissions from fugitives at terminals are very much lower than at refineries because the systems do not operate at such high pressures. The emission factors provided in **Section 13.5**, which were derived from measurements on refinery process plants, should therefore not be used to estimate fugitive emissions at distribution terminals. Equivalent emission factors for terminal equipment are provided in reference [29], Table 2-3. Emissions from this source are typically less than 1 tonne/year for high throughput terminals.

A 4.1.4 Oil-Water Separators

The emission factors provided in **Section 13.6** have been derived from measurements on oil-water separators at refineries and are not appropriate for facilities at distribution terminals due to the differences in inlet conditions.

Emissions can be considered to be negligible if good maintenance and operating procedures are in place.

A 4.2 SERVICE STATIONS

Algorithms are provided for the following sources:

- Storage tanks
- Automobile refuelling

Gasoline vapour emissions at service stations can be controlled using “vapour balancing” techniques:-

> Storage tank filling: When the storage tank is filled the vapours normally vented to atmosphere can be fed back into the tanker cargo tank (compartment) from which the gasoline is being off-loaded. This technique is called “Stage 1b” vapour balancing.
>
> Automobile Refuelling: When an automobile is being refuelled, the vapours normally vented to atmosphere from the fuel tank can be fed back to the service station storage tank from which the gasoline was dispensed. This technique has been mandated in the majority of EU countries and is called “Stage 2” vapour balancing. An alternative, which has been mandated in the USA, is to enlarge the carbon canister fitted on the automobile to control fuel system hot-soak emissions so that refuelling emissions can also be captured.

Other emissions comprise storage tank “breathing” due to evaporation of the gasoline in the tank, and drips and minor spillage during automobile refuelling.

The emissions can be estimated from:

Mass emitted (kg) = EF × $\mathrm{VOL_{DISP}}$ × TVP

where:
EF = Emission Factor from **Table A4.3** depending on source and activity.
$\mathrm{VOL_{DISP}}$ = Volume of gasoline dispensed (in m^3).
TVP = True Vapour Pressure of gasoline at storage temperature (in kPa).

Reference: [7], Section 4.

Table A4.3 NMVOC Emission Factors for Service Stations

SOURCE / ACTIVITY		**EMISSION FACTOR (EF) kg/m^3/kPa**
Storage Tank	Filling without Stage 1b	2.44E-02
	Filling with Stage 1b in operation	1.10E-03
	Breathing	3.30E-03
Automobile Refuelling	Refuelling with no emission controls in operation	3.67E-02
	Refuelling with Stage 2 in operation	3.70E-03
	Drips and minor spillage	2.20E-03

Gasoline TVP can be calculated from:

$$\mathbf{TVP = RVP \times 10^{[(7.047E\text{-}06 \times RVP + 1.392E\text{-}02) \times TEMP + (2.311E\text{-}04 \times RVP - 5.236E\text{-}01)]}}$$

where:
RVP = Reid Vapour Pressure (in kPa)
TEMP = Gasoline storage temperature (in degrees Centigrade)

If the storage tank temperature is unknown, for the estimation of annual emissions TEMP can be assumed to equal the average annual ambient temperature.

Reference: [7], Appendix 1.

APPENDIX 5 CONVERSION FACTORS AND DEFAULT FUEL VALUES

To convert from Higher Heating Value (HHV) to Net Calorific Value (NCV), the following approach, as used in reference [15], was taken.

NCV = HHV x Correction Factor for heat of vaporisation of water in the fuel (CF_{H_2O})

For Liquid Fuels, Correction Factor (CF_{H_2O}) = 0.95
For Gaseous Fuels, Correction Factor (CF_{H_2O}) = 0.9

Reference: [15], Section 3.6.3, Table 3-5.

To convert Emission Factor from lb/MBtu$_{(HHV)}$ to g/GJ$_{(NCV)}$

$$\text{EF g/GJ}_{(NCV)} = (\text{EF lb/MBtu}_{(HHV)} / CF_{H_2O}) \times (\text{g / lb}) \times (\text{MBtu / GJ})$$

To convert Emission Factor from lb/10^3 gal to g/GJ$_{(NCV)}$

$$\text{EF g/GJ}_{(NCV)} = \text{EF lb/}10^3\text{ gal} \times (10^3\text{ gal / MBtu}_{(NCV)}) \times (\text{g / lb}) \times (\text{MBtu / GJ})$$

To convert Emission Factor from lb/10^6 scf to g/GJ$_{(NCV)}$

$$\text{EF g/GJ}_{(NCV)} = \text{EF lb/}10^6\text{ scf} \times (10^6\text{ scf / MBtu}_{(NCV)}) \times (\text{g / lb}) \times (\text{MBtu / GJ})$$

Unless otherwise stated, emission factors were calculated using the following heating values expressed in their original units.

FUEL	HIGHER HEATING VALUE (HHV)	REFERENCE
Distillate (gas oil)	140 MBtu / 10^3 gal	[51]
Diesel Fuel	137 MBtu / 10^3 gal	[51]
Refinery Fuel Oil	150 MBtu / 10^3 gal	[51]
LPG	94 MBtu / 10^3 gal	[51]
Propane	91.5 MBtu / 10^3 gal	[17] Section 1.5.3.1
Natural Gas	1020 MBtu / 10^6 scf	[17] Section 1.4.1

Some useful conversion factors

Refinery Fuel Oil

1 lb/10^3 US gal = 3.017 g/GJ$_{(NCV)}$
1 lb/10^6 Btu$_{(HHV)}$ = 453 g/GJ$_{(NCV)}$

Distillate (Gas Oil)

1 lb/10^3 US gal = 3.233 g/$GJ_{(NCV)}$
1 lb/10^6 $Btu_{(HHV)}$ = 453 g/$GJ_{(NCV)}$

LPG

1 lb/10^3 US gal = 4.815 g/$GJ_{(NCV)}$

Propane

1 lb/10^3 US gal = 4.946 g/$GJ_{(NCV)}$

Natural Gas

1 lb/10^6 scf = 0.468 g/$GJ_{(NCV)}$
1 lb/10^6 $Btu_{(HHV)}$ = 478 g/$GJ_{(NCV)}$

EPA AP42 FG CO. AP42

1.4 NATURAL GAS COMBUSTION

1.4.1 General[1,2]

Natural gas is one of the major fuels used throughout the country. It is used mainly for power generation, for industrial process steam and heat production, and for domestic and commercial space heating. The primary component of natural gas is methane, although varying amounts of ethane and smaller amounts of nitrogen, helium and carbon dioxide are also present. Gas processing plants are required for recovery of liquefiable constituents and removal of hydrogen sulfide (H_2S) before the gas is used (see Natural Gas Processing, Section 9.2). The average gross heating value of natural gas is approximately 9350 kilocalories per standard cubic meter (1050 British thermal units/standard cubic foot), usually varying from 8900 to 9800 kcal/scm (1000 to 1100 Btu/scf).

Because natural gas in its original state is a gaseous, homogenous fluid, its combustion is simple and can be precisely controlled. Common excess air rates range from 10 to 15 percent, but some large units operate at lower excess air rates to increase efficiency and reduce nitrogen oxide (NO_x) emissions.

1.4.2 Emissions and Controls[3-26]

Even though natural gas is considered to be a relatively clean fuel, some emissions can occur from the combustion reaction. For example, improper operating conditions, including poor mixing, insufficient air, etc., may cause large amounts of smoke, carbon monoxide and hydrocarbons to be produced. Moreover, because a sulfur containing mercaptan is added to natural gas for detection purposes, small amounts of sulfur oxides will also be produced in the combustion process.

Nitrogen oxides are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions are functions of combustion chamber temperature and combustion product cooling rate. Emission levels vary considerably with the type and size of unit and with operating conditions.

In some large boilers, several operating modifications may be employed for NO control. Staged combustion for example, including off-stoichiometric firing and/or two stage combustion, can reduce NO emissions by 5 to 50 percent.[26] In off-stoichiometric firing, also called "biased firing", some burners are operated fuel rich, some fuel lean, and others may supply air only. In two stage combustion, the burners are operated fuel rich (by introducing only 70 to 90 percent stoichiometric air), with combustion being completed by air injected above the flame zone through second stage "NO-ports". In staged combustion, NO_x emissions are reduced because the bulk of combustion occurs under fuel rich conditions.

Other NO_x reducing modifications include low excess air firing and flue gas recirculation. In low excess air firing, excess air levels are kept as low as possible without producing unacceptable levels of unburned combustibles (carbon monoxide, volatile organic compounds and smoke) and/or other operational problems. This technique can reduce NO_x emissions by 5 to 35 percent, primarily because of lack of oxygen during combustion. Flue gas recirculation into the primary combustion zone, because the flue gas is relatively cool and oxygen deficient, can also lower NO_x emissions by 4 to 85 percent, depending on the amount of gas recirculated. Flue gas recirculation is best suited for new boilers. Retrofit application would require extensive burner modifications. Initial studies indicate that low NO_x burners (20 to 50 percent reduction) and ammonia injection (40 to 70 percent reduction) also offer NO_x emission reductions.

Combinations of the above combustion modifications may also be employed to reduce NO_x emissions further. In some boilers, for instance, NO_x reductions as high as 70 to 90 percent have been produced by employing several of these techniques simultaneously. In general, however, because the net effect of any of these combinations varies greatly, it is difficult to predict what the reductions will be in any given unit.

Emission factors for natural gas combustion are presented in Table 1.4-1, and factor ratings in Table 1.4-2.

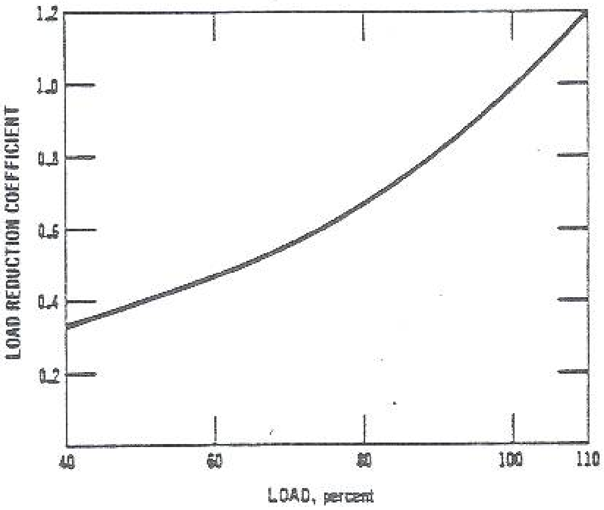

Figure 1.4-1. Load reduction coefficient as function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

TABLE 1.4-1. UNCONTROLLED EMISSION FACTORS FOR NATURAL GAS COMBUSTION[a]

Furnace Size & Type (10^6 Btu/hr heat input)	Particulates[b]		Sulfur Dioxide[c]		Nitrogen Oxide[d,e]		Carbon Monoxide[f,g]		Volatile Organics			
									Nonmethane		Methane	
	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$
Utility boilers (>100)	16-80	1-5	9.6	0.6	8800[h]	550[h]	640	40	23	1.4	4.8	0.3
Industrial boilers (10 - 100)	16-80	1-5	9.6	0.6	2240	140	560	35	44	2.8	48	3
Domestic and commercial boilers (<10)	16-80	1-5	9.6	0.6	1600	100	320	20	84	5.3	43	2.7

[a] All emission factors are expressed as weight per volume fuel fired.

[b] References 15-18.

[c] Reference 4 (based on an average sulfur content of natural gas of 4600 $g/10^6$ Nm^3 (2000 $gr/10^6$ scf).

[d] References 4-5,7-8,11,14,18-19,21.

[e] Expressed as NO_2. Test results indicate that about 95 weight % of NO_x is NO.

[f] References 4,7-8,16,18,22-25.

[g] References 16 and 18. May increase 10 to 100 times with improper operation or maintenance.

[h] Use 4400 $kg/10^6$ m^3 (275 $lb/10^6 ft^3$) for tangentially fired units. At reduced loads, multiply this factor by the load reduction coefficient given in Figure 1.4-1. See text for potential NO_x reductions by combustion modifications. Note that the NO_x reduction from these modifications will also occur at reduced load conditions.

TABLE 1.4-2. FACTOR RATINGS FOR NATURAL GAS COMBUSTION

Furnace Type	Particulates	Sulfur Oxides	Nitrogen Oxides	Carbon Monoxides	VOC	
					Nonmethane	Methane
Utility boiler	B	A	A	A	C	C
Industrial boiler	B	A	A	A	C	C
Commercial boiler	B	A	A	A	D	D
Residential furnace	B	A	A	A	D	D

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