COMBUSTION IN ENERGY AND TRANSFORMATION INDUSTRIES

SNAP CODES: **(See below)**

SOURCE ACTIVITY TITLE: COMBUSTION PLANTS AS POINT SOURCES

The following activities are taken into account, when treating combustion plants individually as point sources.

Combustion plants with a thermal capacity < 300 MW, gas turbines and stationary engines, which may also be considered collectively as area sources, are covered by chapter B112 “Combustion Plants as Area Sources” as well.

SNAP94 Codes	**Combustion plants as point sources** Boilers/Furnaces								
	Thermal capacity [MW]	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
01 01 01	ò 300	x							
01 02 01			x						
01 03 01				x					
01 04 01				x					
01 05 01				x					
02 01 01					x				
03 01 01				x					
01 01 02	ò 50 and < 300	x							
01 02 02			x						
01 03 02				x					
01 04 02				x					
01 05 02				x					
02 01 02					x				
02 02 01						x			
02 03 01							x		
03 01 02				x					
01 01 03	< 50	x							
01 02 03			x						
01 03 03				x					
01 04 03				x					
01 05 03				x					
02 01 03					x				
02 02 02						x			
02 03 02							x		
03 01 03				x					
01 01 04	not relevant							x	
01 02 04								x	
01 03 04								x	
01 04 04								x	
01 05 04								x	
02 01 04								x	
02 02 03								x	
02 03 03								x	
03 01 04								x	
01 01 05	not relevant								x
01 02 05									x
01 03 05									x
01 04 05									x
01 05 05									x
02 01 05									x
02 02 04									x
02 03 04									x
03 01 05									x

x = indicates relevant combination

1 ACTIVITIES INCLUDED

This chapter covers emissions from boilers, gas turbines and stationary engines as point sources. According to CORINAIR90, combustion plants with

– a thermal capacity ≥ 300 MW
  or
– emissions of SO_2 or NO_x or NMVOC > 1,000 Mg/a[1]

should be considered as point sources /41/. Within CORINAIR other combustion plants may also be considered as point sources on a voluntary basis. Different criteria are applied for the classification of combustion plants according to the Large Combustion Plant Directive (88/609/EEC)[2] /9, 42/.

Boilers, gas turbines and stationary engines need to be treated separately (see table at start of this chapter). With regard to boilers, a combustion plant may consist of one single boiler or may comprise a series of boilers of different sizes (joint plant). Therefore, whenever there is more than one boiler on a site, a decision on the aggregation of these facilities to plants has to be taken. Through this decision, an allocation to the respective SNAP categories is achieved. For aggregation criteria see Section 3.2 and Annex 1.

The subdivision of SNAP activities according to CORINAIR90 concerning combustion plants takes into account two criteria:

a) the economic sector concerning the use of energy
  - public power and co-generation,
  - district heating,
  - commercial and institutional combustion,
  - industrial combustion in boilers,
    (Note: Process furnaces are allocated separately.)

b) the technical characteristics
  - with respect to boilers, the installed thermal capacity,
    - ≥ 300 MW,
    - ≥ 50 to < 300 MW,
    - ≤ 50 MW,
  - other combustion technologies,
    - gas turbines,
    - stationary engines.

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[1] For CO_2 a further optional criterion for point sources is the emission of > 300 Gg/a.

[2] The Large Combustion Plant Directive covers combustion plants with a thermal capacity ≥ 50 MW in the EU. Gas turbines and stationary engines are excluded. Existing plants with a thermal capacity > 300 MW have to be reported as point sources on an individual basis.

Emissions considered in this section are released by a controlled combustion process (boiler emissions, emissions from the combustion chamber of gas turbines or stationary engines), taking into account primary reduction measures, such as furnace optimisation inside the boiler or the combustion chamber, and secondary reduction measures downstream of the boiler or the combustion chamber. Solid, liquid or gaseous fuels are used, where solid fuels comprise coal, coke, biomass and waste (as far as waste is used to generate heat or power). In addition, a non-combustion process can be a source of ammonia emissions, namely ammonia slip in connection with several NO_x abatement techniques.

2 CONTRIBUTION TO TOTAL EMISSIONS

This section covers emissions of SO_x, NO_x, CO, CO_2, NMVOC, CH_4, N_2O, NH_3 and heavy metals (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn, V). The contributions of point source emissions released by combustion plants to the total emissions in countries of the CORINAIR90 inventory are given as follows in Table 1:

Table 1: Contributions of emissions from combustion plants as point sources to total emissions of the CORINAIR90 inventory reported as point sources

		Contribution to total emissions [%]							
Source category	SNAP90 code	SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3
≥ 300 MW	01 01 01 01 02 01 03 01 01	85.6	81.4	10.2	5.5	16.8	79.0	35.7	2.4
50-300 MW	01 01 02 01 02 02 02 00 01 03 01 02	6.4	5.4	1.1	0.6	3.1	6.5	1.9	0.2
< 50 MW	01 01 03 01 02 03 02 00 02 03 01 03	0.2	0.3	0.1	0.05	0.1	0.2	0.1	0
Gas turbines[1)]	01 01 04 01 02 04 02 00 03 03 01 04	0	0.39	0.07	0.06	0.05	0.35	0.02	-
Stationary engines[1)]	01 01 05 01 02 05 02 00 04 03 01 05	0.04	0.10	0.04	0	0.01	0.02	0	-

- : no emissions are reported

0 : emissions are reported, but the precise number is under the rounding limit

[1)] Gas turbines and stationary engines may be reported either as point or as area sources.

In the literature concerning heavy metal emissions across Europe, point source emissions are not reported separately. Giving an order of magnitude of heavy metal emissions released from combustion plants emission data of coal-fired public power plants in Germany and Austria is presented here as an example, due to the availability of data:

Table 2: Contributions of heavy metal emissions from coal-fired public power plants to national total emissions of Germany[1] /36/

	Contribution in [wt.-%]	
Pollutant	1982	1990
As	38	27
Cd[2]	7	7
Cr	12	4
Cu	22	8
Hg[3]	11	14
Ni	5	4
Pb	8	1
Se	1	1
Zn	7	6

[1] Western part of Germany

[2] E.g. emissions of Cd in Austria in 1992 were 0,2 % /37/.

[3] E.g. emissions of Hg in Austria in 1992 were 6 % /37/.

By comparing the heavy metal emissions in 1982 (without flue gas desulphurisation (FGD) installed) to the emissions in 1990 (where most plants are equipped with FGD), it can be seen that the application of FGD technologies has lead to a significant decrease in heavy metal emissions within the last years.

3 GENERAL

3.1 Description

The emissions considered in this chapter are generated either by boilers or by gas turbines and stationary engines regardless of the allocation of plants to SNAP activities. Emissions from process furnaces (combustion with contact) and from waste incineration are not included here (therefore see SNAP code 090200).

3.2 Definitions

ar	as received, a reference state of coal which determines the conditions, when coal arrives at the plant /73/.
Availability (of an abatement technology)	ratio of full load operating hours with operating emission control technology to total full load operating hours of the power plant; the availability β normally amounts to 99 %; but extreme low values of β can occur down to 95 %. By taking into account the start-up behaviour of emission reduction technologies, the availability β can decrease further down to 92 %. Default values are proposed in Tables 7 and 11.
Boiler	any technical apparatus, in which fuels are oxidised in order to generate heat for locally separate use.
Coking coal (NAPFUE 101)	subcategory of hard coal with a quality that allows the production of a coke suitable for supporting a blast furnace charge /114/.
Co-generation plant	steam production in boilers (one or more boilers) for both, power generation (in a steam turbine) and heat supply.
Combined Cycle Gas Turbine (CCGT)	gas turbine combined with a steam turbine. The boiler can also be fuelled separately.
daf	dry and ash free, a reference state of coal which is calculated with reference to a theoretical base of no moisture or ash associated with the sample (equivalent to maf - moisture and ash free) /73/.
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[3] of vitrinite of at least 0.6. Hard coal comprises the subcategories coking coal and steam coal[4] /114/.

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[3] Mean random reflectance: characteristic value, which stands for a defined coal composition (modular component is e.g. vitrinite).

[4] The following coal classification codes cover those coals, which would fall into these subcategories /114/:

International classification codes (UN, Geneva, 19956)	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.

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 /114/.
maf	moisture and ash free, a reference state of coal (equivalent to daf - dry and ash free) /73/.
Plant/Joint Plant	classification with respect to boilers (one or more boilers) according to the respective boiler configuration on a given site and the applied concept of aggregation. The stack-by-stack principle considers all boilers linked to the same stack as a common plant. On the other hand, according to the virtual stack principle, all boilers which, for technical and economic reasons, could be connected to a common stack, are treated as one unit. It is also possible to carry out a still broader combination following e.g. administrative aspects. Gas turbines and stationary engines are allocated separately. A typical example of different allocation possibilities of boilers to the SNAP codes is given in Annex 1.
Power plant	steam generation in boilers (one or more boilers) for power generation.
Reduction efficiency (of an abatement technology)	difference between the pollutant concentration in the raw gas (c_{raw}) and the pollutant concentration in the clean gas (c_{clean}) divided by the pollutant concentration in the raw gas (referred to full load operating hours); default values for the reduction efficiency $\eta = (c_{raw} - c_{clean})/c_{raw}$ of different emission control technologies are recommended in Tables 7 and 11 (extreme low values of η can be up to ten percent below the values given).
Start-up emission	here start-up emissions have been considered for boilers equipped with secondary measures: For SO_2 and NO_2 from the time when burners switch on up to the time when the secondary abatement facility operates under optimum conditions; for CO up to the time when the boiler operates at minimum load.
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 /114/.

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 /114/
Sulphur retention in ash	difference between the sulphur dioxide concentration calculated from the total sulphur content of fuel (c_{max}) and the sulphur dioxide concentration of the flue gas (c_{eff}) divided by the sulphur dioxide concentration calculated from the total sulphur content of the fuel. Default values for the sulphur retention in ash $\alpha_s = (c_{max} - c_{eff})/c_{max}$ are proposed in Table 8.

3.3 Techniques

3.3.1 Combustion of coal

3.3.1.1 Dry bottom boiler (DBB)

The DBB is characterised by the dry ash discharge from the combustion chamber due to combustion temperatures from 900 up to 1,200 °C. This type of boiler is mainly used for the combustion of hard coal and lignite and is applied all over Europe.

3.3.1.2 Wet bottom boiler (WBB)

Typical combustion temperatures exceeding 1,400 °C lead 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.

3.3.1.3 Fluidised bed combustion (FBC)

The combustion of coal takes place by injection of combustion air through the bottom of the boiler into a turbulent bed. The typical relatively low emissions are achieved by air staging, limestone addition and low combustion temperatures of about 750 - 950 °C. FBC is in particular adapted to coals rich in ash. Only few large combustion plants are equipped with the FBC technique; in the category of thermal capacities ≥ 300 MW mostly Circulating Fluidised Bed Combustion (CFBC) is installed.

3.3.1.4 Grate Firing (GF)

The lump fuel (coal, waste) is charged on a stationary or slowly moving grate. The combustion temperatures are mainly between 1,000 and 1,300 °C.

3.3.2 Combustion of biomass

The combustion of biomass (peat, straw, wood) is only relevant for some countries (e.g. Finland, Denmark). FBC (mostly CFBC) and DBB facilities are installed.

3.3.3 Combustion of waste

For the combustion of waste, mostly grate firing installations are in use.

3.3.4 Combustion of gas/oil

3.3.4.1 Combustion in boilers (general aspects of the combustion techniques)

For both, gas and oil combustion, the fuel and oxidising agents are gaseous under combustion conditions. The main distinctions between gas/oil combustion and pulverised coal combustion are the operation designs of the individual burners of the boiler. With respect to emissions, a principal distinction can be made between burners with and without a pre-mix of fuel and combustion air: pre-mixing burners are characterised by a homogeneous short flame and a high conversion rate of fuel bound nitrogen; non-pre-mixing burners are characterised by inhomogeneous flames with understoichiometric reaction zones and a lower conversion rate of fuel bound nitrogen.

The importance of oil and gas combustion considered as point sources (see Section 1) is low compared to coal combustion, due to the smaller total capacity of these installations. The main parameters determining emissions from oil and gas fired plants are given in Table 3.

Table 3: Main parameters determining emissions from oil and gas fired boilers /40/

Pollutant	Fuel dependent	Process dependent
	Oil-fired boiler	
SO_2	x	-
NO_x	x	x
CO	-	x
	Gas-fired boiler	
SO_2	x$^{1)}$	-
NO_x	-	x
CO	-	x

$^{1)}$ trace amounts x : relevant - : not relevant

3.3.4.2 Gas turbines

Gas turbines are installed with a thermal capacity ranging from several hundred kW up to 500 MW. Gaseous fuels are mainly used, such as natural gas or the product of coal gasification (e.g. CCGT or IGCC installations) or other process gases. Also liquid fuels are used, such as light distillates (e.g. naphtha, kerosene or fuel oil) and in some cases other fuels (e.g. heavy fuel oil). Combustion temperatures of up to 1,300 °C in the combustion chambers may lead to considerable NO_X emissions.

Gas turbines are installed as a part of different types of combustion plants such as Combined Cycle Gas Turbine (CCGT) or Integrated Coal Gasification Combined Cycle Gas Turbine (IGCC) Plants (see also Section 3.2). For IGCC plants, the only emission relevant unit considered here is the gas turbine (combustion chamber). For CCGT, in addition to the gas turbine any installed fossil fuelled boiler should also be taken into account.

3.3.4.3 Stationary engines

Stationary engines are installed as spark-ignition engines and compression-ignition engines (2- and 4-stroke) with electrical outputs ranging from less than 100 kW to over 10 MW (e.g. in co-generation plants) /cf. 46/. Both types represent relevant emission sources.

3.4 Emissions

Relevant pollutants are sulphur oxides (SO_x), nitrogen oxides (NO_x), carbon dioxide (CO_2) and heavy metals (arsenic (As), cadmium (Cd), chromium (Cr), copper (Cu), mercury (Hg), nickel (Ni), lead (Pb), selenium (Se), zinc (Zn) and in the case of heavy oil also vanadium (V)). Emissions of volatile organic compounds (non-methane VOC and methane (CH_4)), nitrous oxide (N_2O), carbon monoxide (CO) and ammonia (NH_3) are of less importance. For species profiles of selected pollutants see section 9.

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.-% /15, 16/; usually, the sulphur content of gas is negligible. 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. The total sulphur content of coal is usually determined by wet chemical methods; by comparison with results from the X-ray method, it has been found that standard analytical procedures may overestimate the organic sulphur content of coal /30/. The uncertainty introduced by the analytical procedures should be determined by further research.

For nitric oxide (NO, together with NO_2 normally expressed as nitrogen oxides NO_x) three different formation mechanisms have to be distinguished (see also Section 9):

-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 "prompt6-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) /17/. 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.-% /17/. 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 (cf. /24/).

Carbon monoxide (CO) appears always as an intermediate product of the combustion process and in particular under understoichiometric combustion conditions. However, the relevance of CO released from combustion plants is not very high compared to CO_2. The formation mechanisms of CO, thermal-NO and VOC are similarly influenced by combustion conditions.

Carbon dioxide (CO_2) is a main product from the combustion of all fossil fuels. The CO_2 emission is directly related to the carbon content of fuels. The content of carbon varies for hard and brown coal between 61 and 87 wt.-% (maf), for wood it is about 50 wt.-% and for gas oil and heavy fuel oil about 85 wt.-% .

The formation mechanism of nitrous oxide (N_2O) has not yet been completely clarified. There is a possible formation mechanism based on intermediate products (HCN, NH_3), which is comparable to the formation of NO /55/. It has been found, that lower combustion temperatures, particularly below 1,000 °C, cause higher N_2O emissions /13/. At lower temperatures the N_2O molecule is relatively stable; at higher temperatures the N_2O formed is reduced to N_2 /55/. Compared to emissions from conventional stationary combustion units, nitrous oxides from either bubbling, circulating or pressurised fluidised bed combustion are relatively high /13, 14/. In laboratory experiments, it has been found that nitrous oxide is formed by Selective Catalytic Reduction (SCR) processes, passing a maximum at, or close to, the optimum temperature "window" of the SCR process /13/.

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, 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, an 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. The concentrations are reported to be in the range of 2 - 5 $\mu g/m^3$ for natural gas /35, 63/. 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). /10, 11, 12/

3.5 Controls

Relevant abatement technologies for SO_x, 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 7, 10, and 11. Due to the fact, that most published studies do not clearly distinguish between SO_x and SO_2, for the following chapters, it can be assumed that SO_2 includes SO_3, if not stated otherwise.

3.5.1 Sulphur oxides: Flue Gas Desulphurisation Processes (FGD) (Secondary measures) /cf. 18/

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 also SO_3, fluorides and chlorides are removed. In the case of the DESONOX process (see Section 3.5.4.2), the SO_2 is catalytically oxidised to SO_3 and reacts with water to form sulphuric acid. The Activated Carbon process (see Section 3.5.4.1) 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.

3.5.1.1 Lime/Limestone Wet Scrubbing (WS)

The pollutants are removed from the flue gas by chemical reactions with an alkaline liquid (suspension of calcium compounds in water). The main product is gypsum. The WS process represents about 90 % of the total FGD-equipped electrical capacity installed in European 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.-%. Other fossil fuels (such as peat) are presently rarely used at combustion plants with a thermal capacity ≥ 300 MW. The SO_2 reduction efficiency is > 90 %.

3.5.1.2 Spray Dryer Absorption (SDA)

The SDA process removes the pollutant components from flue gas of fossil fired combustion units by injection of $Ca(OH)_2$. The process forms a dry by-product ($CaSO_3 \cdot 1/2\ H_2O$). This technology covers about 8 % of the total FGD-equipped electrical capacity installed in the European OECD countries. The SDA process is mostly in use at hard coal fired combustion units (sulphur content of fuel up to 3 wt.-%). Recent pilot studies have shown that this technique is also operational with other fossil fuels (oil, lignite, peat). The SO_2 reduction efficiency is > 90 %.

3.5.1.3 Dry Sorbent Injection (DSI, LIFAC Process)

The DSI process is based on a gas/solid reaction of the flue gas and a dry sorbent (e.g. lime/limestone, sodium hydrogen carbonate $NaHCO_3$) inside the boiler. There are three different process types according to the injection point of the additive into the boiler (e.g. primary or secondary air, flame front). The by-products are a dry mixture of the respective salts (mostly $CaSO_4$). Only few power plants (some 5 % of the total FGD-equipped electrical capacity installed in European OECD countries) are equipped with this technology due to its low SO_2 reduction efficiency of 40 - 50 %, which is not sufficient to meet the emission standards of some countries. DSI processes are presently in use for hard coal, lignite, oil and coal/oil fired boilers. The optimum reduction efficiency is obtained for the sulphur contents of fuel between 0.5 and 1.7 wt.-% (max. 2 wt.-%).

The LIFAC process is an advanced dry sorbent injection process using additional water injection in a separate reactor downstream of the boiler, in order to raise the reduction efficiency. Generally, the SO_2 reduction efficiency is > 50 %. At present, the LIFAC process is used in one plant in Finland with a SO_2 reduction efficiency of already 70 %.

3.5.1.4 Wellman-Lord (WL)

The WL process is a regenerable FGD process, which uses the sodium sulphite (Na_2SO_3)/ sodium bisulphite ($NaHSO_3$) equilibrium in order to remove SO_2 from the flue gas. An SO_2-rich gas is obtained, which is used for the production of sulphuric acid. At present only three installations with a total thermal capacity of 3,300 MW are in use (in Germany), due to the complexity of the process and the resulting high investments and operating costs (this technology represents about 3 % of the total thermal capacity installed in the European OECD countries). The WL process is operational with various types of fuel (e.g. hard coal, oil), especially with high sulphur contents (of about 3.5 wt.-%). The SO_2 reduction efficiency is > 97 %.

3.5.1.5 Walther Process (WAP)

The WAP process uses ammonia water in order to remove SO_2 from the flue gas. The by-product is a dry salt mixture of the respective ammonia salts (mainly ammonium sulphate ($(NH_4)_2SO_4$). One reference installation is currently operating in Germany. This process is operational with all types of fuel. However, the maximum sulphur content should be limited to 2 wt.-% (due to the increasing formation of ammonia sulphate aerosols). The SO_2 reduction efficiency is > 88 %.

3.5.2 Nitrogen oxides: Primary measures - Denitrification techniques /cf. 17, 18, 19/

3.5.2.1 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 understoichiometric 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 overstoichiometric 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 % (see Table 10).

3.5.2.2 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 % (see Table 10).

3.5.2.3 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 % (see Table 10).

3.5.2.4 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 % (see Table 10).

3.5.2.5 Split Primary Flow (SPF)

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 understoichiometric 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, natural gas is the most appropriate reburning fuel. NO_x reduction efficiencies have not been yet reported.

3.5.3 Nitrogen oxides: Secondary measures - Denitrification Processes /cf. 18, 19/

3.5.3.1 Selective Non-Catalytic Reduction (SNCR)

The reduction of nitrogen oxides in the flue gas is based on the selective reaction of NO_x with injected ammonia, urea or caustic ammonia to form nitrogen and water. The SNCR process has been implemented at several installations (e.g. in Germany, in Austria and in Sweden) and has in principle proved to be operational with various types of fuels. The NO_x reduction efficiency is about 50 %, in some installations up to 80 %.

3.5.3.2 Selective Catalytic Reduction (SCR)

The reduction of nitrogen oxides is based on selective reactions with injected additives in the presence of a catalyst. The additives used are mostly gaseous ammonia, but also liquid caustic ammonia or urea. The SCR technology accounts for about 95 % of all denitrification processes. SCR is mostly used for hard coal. For brown coal, lower combustion temperatures lead to lower NO_x formation, so that primary measures fulfil the emission reduction requirements. Several heavy metals in the flue gas can cause rapid deactivation of the catalyst. The NO_x reduction efficiency varies between 70 and 90 %.

3.5.4 Nitrogen oxides and sulphur oxides: Simultaneous Processes /18, 19/

3.5.4.1 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 an 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 %.

3.5.4.2 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.

3.5.5 Heavy metals: Secondary measures /12, 20, 21, 22, 23/

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 SCR-unit 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.

3.5.6 Gas turbines /cf. 68, 69/

For gas turbines mainly NO_X emissions are of most relevance. Primary measures for NO_X reduction are the following: dry controls (e.g. overstoichiometric combustion in a dry low NO_X burner with $\eta = 0.6 - 0.8$, which is a relatively new development as a primary measure) and wet controls (injection of water and/or steam with $\eta \geq 0.6$ /114/) in order to regulate the combustion temperature. For large gas turbines secondary measures are also installed such as Selective Catalytic Reduction (SCR).

3.5.7 Stationary engines /cf. 70/

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 at this stage insufficient information is available /35/.

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 %. /cf. 114/

Secondary measures are installed, if the emission thresholds cannot be met by adjustments to the engine itself. The following methods are used depending on the air ratio λ:

$\lambda = 1$ Reduction of NO_X, CO and VOC by using a three-way catalytic converter (NSCR),

$\lambda > 1$ Reduction of NO_X by Selective Catalytic Reduction with NH_3 (SCR), Reduction of other emissions (CO, VOC) using oxidation catalytic converter (NSCR).

Typical conversion rates of NO_x range from 80 to 95 % with corresponding decreases in CO and VOC. Depending on the system design, NO_x removal of 80 up to 90 % is achievable. /114/

4 SIMPLER METHODOLOGY

4.1 General

4.1.1 General / specified emission factors

Here “simpler methodology“ refers to the calculation of emissions, based on emission factors and activities. The simpler methodology should only be used in cases where no measured data is available. The simpler methodology covers all relevant pollutants (SO_2, NO_x, NMVOC, CH_4, CO, CO_2, N_2O, NH_3, heavy metals). Special emphasis is put on the pollutants SO_x, NO_x and heavy metals, due to the significant contribution of combustion plants as point sources to the total emissions of these pollutants.

A combustion plant can be treated either as a whole (irrespective of kind/size of individual boilers) or on a boiler-by-boiler level. Differences in design and operation of boilers, in fuels used and/or controls installed require different emission factors. The same applies to gas turbines and stationary engines.

The annual emission E is derived from an activity A and a factor which determines their linear relation (see Equation (1)):

$$E_i = EF_i \cdot A \tag{1}$$

E_i	annual emission of pollutant i
EF_i	emission factor of pollutant i
A	activity rate

The activity rate A and the emission factor EF_i have to be determined on the same level of aggregation by using available data (e.g. fuel consumption) (see Section 6). For the activity rate A, the energy input in [GJ] should be used, but in principle other relations are also applicable.

Two different approaches in order to obtain the emission factor EF_i are proposed:

- General emission factor EF_{G_i}

The general emission factor is a mean value for defined categories of boilers taking into account abatement measures (primary and secondary). A general emission factor is only related to the type of fuel used and is applicable for all pollutants considered, except of SO_2[5]. It should only be used where no technique specific data are available (only as a makeshift).

- Specified emission factor EF_{R_i}

The specified emission factor is an individually determined value for boilers taking into account abatement measures (primary and secondary). A specified emission factor is related to individual fuel characteristics (e.g. sulphur content of fuel) and to technology specific parameters. The following sections provide determination procedures for suitable specified emission factors for the pollutants NO_x, SO_x and heavy metals.

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[5] For the appropriate determination of SO_2 emissions the sulphur content of fuel is required. Therefore, the specified emission factor approach has to be applied.

In principle, plant specific data should be used, if available, for the determination of emission factors. The following Sections 4.1 to 4.8 give recommendations for the estimation and the use of general and specified emission factors as given in Table 4.

Table 4: Applicability of general emission factors EF_{Gi} and specified emission factors EF_{R_i}

Pollutant	General emission factor EF_{Gi}	Specified emission factor EF_{R_i}
SO_x	-	+
NO_x	+	++[1)]
Heavy metals	+	++[2)]
NMVOC, CH_4, CO, CO_2, N_2O, NH_3	+	*

+ : possible, but not recommended methodology; ++ : possible and recommended methodology;

- : not appropriate; * : not available

1) detailed calculation schemes are given for pulverised coal combustion

2) detailed calculation schemes are given for coal combustion

An accurate determination of full load emissions can only be obtained by using specified emission factors. For the calculation of specified SO_x and NO_x emission factors for pulverised coal combustion, a computer programme has been developed (see Annexes 2 - 6 and Annex 14).

If not stated otherwise, the general and specified emission factors presented refer to full load conditions. Start-up emissions have to be considered separately (see Section 4.1.2).

4.1.2 Start-up dependence

Start-up emissions depend on the load design of the plant and on the type of start-up (see Tables 5 and 6). A plant can be designed for:

- peak load: to meet the short-term energy demand,
- middle load: to meet the energy demand on working days,
- base load: continuous operation.

Table 5: Load design and start-ups per year

Load design	Start-ups per year		Full load hours per year		Emission
	range	value	range	value	relevance[2)]
Peak load[1)]	150 - 500	200	1,000 - 2,500	2,000	x[1)]
Middle load	50 - 250	150	3,000 - 5,000	4,000	xxx
Base load	10 - 20	15	6,000 - 8,000	7,000	x

1) For peak load often high-quality fuels (e.g. gas, oil) and often gas turbines are used.

2) x: low; xxx: high.

Table 6: Status of the boiler at starting time for a conventional power plant

Type of start-up	Time of stand-still [h] /65/	Status of the boiler	Frequency[2)]	Emission relevance[2)]
Hot-start	< 8	hot	xxx	x
Warm-start	8 - ca. 50	warm	xx	xx
Cold-start	> 50	cold	x[1)]	xxx

[1)] normally once a year, only for maintenance.

[2)] x: low; xx: medium; xxx: high.

In order to take into consideration the relevance of start-up emissions, a detailed investigation has been carried out. There, start-up emissions and start-up emission factors have been determined for different types of boilers (DBB, WBB, gas-fired boiler, see Annex 15). Start-up emissions are only relevant if secondary measures are installed.

By taking into account boiler characteristics as given in Annex 15, the following general trends of start-up emissions of SO_x, NO_x and CO on the type of fuel and type of boiler are obtained (based on /116/).

- For the boilers considered in the detailed investigation it has been found that start-up emissions for the combustion of coal are significantly higher than for the combustion of gas.
- Start-up emissions are higher for dry bottom boilers than for wet bottom boilers and gas boilers.

In the following sections, start-up emissions and start-up emission factors derived from measured data are presented as ratios:

$$F^{EF} = EF^{A} / EF^{V} \qquad (2)$$

F^{EF} ratio of start-up and full load emission factors [ ]

EF^{A} emission factor at start-up period [g/GJ]

EF^{v} emission factor at full load conditions [g/GJ]

$$F^{E} = E^{A} / E^{V} \qquad (3)$$

F^{E} ratio of start-up and full load emissions [ ]

E^{A} emission during start-up period (see Section 3.2) [Mg]

E^{v} emission for full load conditions during start-up period [Mg]

Start-up emissions and full load emissions are related to comparable periods; the energy input (fuel consumption) during the start-up period is lower than during full load operation. The emission factor ratio F^{EF} is often higher than the emission ratio F^{E}. Increased specific emissions during the start-up period were found to be compensated to a high degree by the lower fuel consumption. Further pollutant specific results are given in the Sections 4.2 - 4.9.

If start-up emissions are taken into account the corresponding activity rates have to be determined as follows:

$$A = A_{\text{full load}} + A_{\text{cold}} + A_{\text{warm}} + A_{\text{hot}} \qquad (4a)$$

A	activity rate within the period considered [GJ]
$A_{\text{full load}}$	activity rate for full load operation periods [GJ]
A_{cold}	activity rate for cold start periods [GJ]
A_{warm}	activity rate for warm start periods [GJ]
A_{hot}	activity rate for hot start periods [GJ]

Each sub-activity (e.g. A_{cold}) has to be determined separately by totalling the thermal energy input for the respective periods e.g. cold start periods.

Accordingly, Equation (1) becomes:

$$E = EF^{V} \cdot (A_{\text{full load}} + F^{EF}_{\text{cold}} \cdot A_{\text{cold}} + F^{EF}_{\text{warm}} \cdot A_{\text{warm}} + F^{EF}_{\text{hot}} \cdot A_{\text{hot}}) \cdot 10^{-6} \qquad (4b)$$

E	emission within the period considered [Mg]
EF^{V}	emission factor at full load operation conditions [g/GJ]
$F^{EF}_{\text{cold/warm/hot}}$	ratio of start-up (cold/warm/hot start) to full load emission factor [ ]
$A_{\text{full load/cold/...}}$	activity rates at full load operation/cold start/... [GJ]

The emission factor at full load conditions EF^{V} can be approximated by using the emission factors given in Tables 24 and 25 (for NO_x) and Table 28 (for CO); SO_2 emission factors can be determined as given in Equation (5). A correction factor for the annual emission can be obtained by calculating the ratio of the annual emissions resulting from Equation (4b) to those determined without consideration of start-up emissions.

4.1.3 Load dependence

A load dependence of emissions has only been found for NO_x emissions released from older types of boiler (see Section 4.3).

4.2 SO_2 emission factors

For SO_2, only specified emission factors $EF_{R_{SO2}}$ are recommended here. For the determination of specified SO_2 emission factors the following general equation should be used (for emissions of SO_3 see Section 9):

$$EF_{R_{SO2}} = 2 \cdot C_{S_{fuel}} \cdot (1 - \alpha_S) \cdot \frac{1}{H_u} \cdot 10^6 \cdot (1 - \eta_{sec} \cdot \beta) \qquad (5)$$

$EF_{R_{SO2}}$	specified emission factor [g/GJ]
$C_{S_{fuel}}$	sulphur content in fuel [kg/kg]
α_s	sulphur retention in ash [ ]
H_u	lower heating value of fuel [MJ/kg]
η_{sec}	reduction efficiency of secondary measure [ ]
β	availability of secondary measure [ ]

Equation (5) can be used for all fuels, but not all parameters may be of relevance for certain fuels (e.g. α_s for gas). Default values for reduction efficiencies and availabilities of secondary measures installed are presented in Table 7. The technologies listed in Table 7 are mainly installed in the case of coal-fired boilers, but they can also be applied when burning other fuels.

Table 7: Default values for secondary measures for SO_2 reduction (all fuels) /18, 19/

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

4.2.1 Combustion of coal

SO_2 emission factors for coal fired boilers can be calculated by using Equation (5). If some input data are not available, provided default values based on literature data can be used:

- $C_{s,fuel}$	see Annexes 7 and 8, Table 23,
- α_s	see Table 8,
- η_{sec} and β	see Table 7,
- H_u	see Annexes 7 and 8.

For further details concerning the calculation of SO_2 emission factors, see Annexes 2 (flowsheet of the computer programme) and 3 (description of the computer programme). Default values for sulphur retention in ash for coal fired boilers are presented in Table 8.

Table 8: Default values for the sulphur retention in ash (α_S) for pulverised coal fired boilers

Type of boiler	α_S [ ]	
	Hard coal	Brown coal
DBB	0.05	0.3[1]
WBB	0.01	-

[1] average value; in practice, a range of 0.05 - 0.60 can occur (e.g. in the Czech Republic 0.05 is used)

Emission factors obtained by using Equation (5) are related to full load conditions; start-up emissions are not taken into account. If a flue gas desulphurisation unit is installed, start-up emissions should be considered as given in Section 4.1.2. The relevance of start-up emissions of SO_2 depends strongly on the following parameters:

- the type of fuel (e.g. SO_x emissions are directly related to the fuel sulphur content),
- the status of the boiler at starting time (hot, warm or cold start, see also Table 6),
- start-up of the flue gas desulphurisation unit (FGD direct or in by-pass configuration),
- limit for SO_x emissions, which has to be met (boiler specific limits can be set up below the demands of the LCP Directive).

For the combustion of coal in dry bottom boilers, the following ranges and values of F^{EF}, F^{E} have been obtained within the investigation outlined in Annex 15:

Table 9: Ratios of start-up to full load emission factors F^{EF} and ratios of start-up to full load emissions F^{E} for SO_2 for dry bottom boilers

	Ratio of start-up to full load emission factors F^{EF} [ ]	Ratio of start-up to full load emissions F^{E} [ ]
Range	3 - max. 16	1 - max. 4
Values for direct start-up of the FGD	F^{EF}_{cold}: 5 F^{EF}_{warm}: 5 F^{EF}_{hot}: 4	F^{E}_{cold}: 1 F^{E}_{warm}: 1 F^{E}_{hot}: 1
Values for by-pass start-up of the FGD	F^{EF}_{cold}: 8.5 - 16 F^{EF}_{warm}: 5 - 14.5 F^{EF}_{hot}: 5 - 5.5	F^{E}_{cold}: 2 - 4.5 F^{E}_{warm}: 1 - 3.5 F^{E}_{hot}: 1.5

$F^{EF}_{cold,warm,hot}$	Ratio of start-up to full load emission factors for cold, warm or hot start-ups (see also Table 6)
$F^{E}_{cold,warm,hot}$	Ratio of start-up to full load emissions for cold, warm or hot start-ups (see also Table 6)

The values from the direct start-up of the FGD show, that start-up emissions of SO_2 are not relevant (ratio F^{E} of ca. 1). In the case of a by-pass start-up of the FGD, start-up emissions of SO_2 are significant for hot, warm and cold starts; start-up emissions can be up to 4 times higher than emissions in a comparable full load time span (based on /116/).

4.2.2 Combustion of other fuels (biomass, waste, liquid fuels, gaseous fuels)

SO_2 emissions are directly related to the sulphur content of biomass, waste, liquid and gaseous fuels (see Equation (5)). The sulphur retention in ash α_s is not relevant. The reduction efficiency η_{sec} and the availability β of installed secondary measures have to be taken into account (in particular for the combustion of waste). Default values for η and β are given in Table 7. Sulphur contents of different fuels are given in Table 23 and in Annexes 7 and 8.

4.3 NO_x emission factors

For the determination of NO_x emissions, general as well as specified NO_x emission factors can be used. Emission factors are listed in Tables 24 and 25 depending on installed capacity, type of boiler, primary measures and type of fuel used.

4.3.1 Combustion of pulverised coal

Specified NO_x emission factors can be calculated individually for pulverised coal fired boilers. Due to the complex reaction mechanism of NO_x formation (see also Section 3.4) an estimate of specified NO_x emission factors can only be made on the basis of empirical relations as given in Equation (6). The decisive step in Equation (6) is the undisturbed NO_x formation (without primary measures) inside the boiler ($C_{NO_{2.boiler}}$). $C_{NO_{2.boiler}}$ is determined by an empirical equation depending on fuel parameters only, as described in Annex 5.

$$EF_{R_{NO_2}} = C_{NO_2,boiler} \cdot (1-\eta_{prim}) \cdot \frac{1}{H_u} \cdot 10^6 \cdot (1-\eta_{sec}\,\beta) \tag{6}$$

$EF_{R_{NO2}}$	specified emission factor [g/GJ]
$C_{NO_{2.boiler}}$	total content of nitrogen dioxide formed in the boiler without taking into account primary reduction measures (in mass NO_2/mass fuel [kg/kg])[6]
η_{prim}	reduction efficiency of primary measures [ ]
H_u	lower heating value of fuel [MJ/kg]
η_{sec}	reduction efficiency of secondary measure [ ]
β	availability of secondary measure

For further details concerning the calculation of specified NO_2 emission factors see Annexes 4 (flowsheet of the computer programme) and 5 (description of the computer programme).

If some input data are not available, default values based on literature data are provided for:

- $C_{N,\ fuel}$, content of fuel-nitrogen,	see Annexes 7 and 8,
- $C_{volatiles}$, content of volatiles in the fuel,	see Annexes 7 and 8,
- η_{prim}	see Table 10,
- η_{sec} and β	see Table 11,
- H_u	see Annexes 7 and 8.

Default values for the reduction efficiency of primary measures are presented in the following Tables 10 and 11.

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[6] Note: The computer programme, which is described in Annex 5, provides $C_{NO2\ boiler}$ as (mass pollutant/mass flue gas [kg/kg]).

Table 10: Reduction efficiencies for selected primary measures for NO_X emissions in coal fired boilers /17, 18, 19, 28, 31, 32, 33, 34, 53/ (value means recommended value)

Type of primary measure1)	Reduction efficiency DBB η [ ]				Reduction efficiency WBB η [ ]	
	Hard coal		Lignite		Hard coal	
	range	value3)	range	value3)	range	value3)
no measure4)	0	0	0	0	0	0
LNB	0.10 - 0.30	0.20	0.10 - 0.30	0.20	0.10 - 0.30	0.20
SAS	0.10 - 0.40	0.30	0.10 - 0.40	0.30	0.10 - 0.40	0.30
OFA	0.10 - 0.40	0.30	0.10 - 0.35	0.25	0.10 - 0.35	0.25
FGR	0.05 - 0.15	0.10	0.05 - 0.20	0.15	0.10 - 0.25	0.20
LNB/SAS	0.20 - 0.60	0.45	0.20 - 0.60	0.45	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 operation2)		0.15		0.15		0.15
old installation/ retrofitted2)		0.50		0.50		0.50
new installation2)		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 11: Default values for reduction efficiency and availability of secondary measures for NO_X reduction /18, 19/ (all fuels)

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

Emission factors of NO_2 for different coal compositions have been calculated by using default values as given above and are listed in Table 25.

The load dependence of NO_X emissions can be split into two different phenomena (see Sections 4.1.2 and 4.1.3):

a) Load variations during normal operation:
Load variations are discussed very controversially in the literature. Often a strong correlation of NO_X emissions and load is reported. Load corrections, e.g. as given in /66/, may be appropriate for older types of boilers.

For boilers of modern design, with optimised combustion conditions e.g. by primary measures, only a negligible load dependence has been reported /64/. This is explained by the fact that for modern boilers (with primary measures) under reduced load conditions an overstoichiometric air ratio is applied in order to achieve an acceptable burning out of the fuel, which leads to NO_x emission factors similar to those obtained under full load conditions. Therefore, for boilers of modern design no load correction is proposed.

For older boilers (without primary measures) a load dependent emission factor can be calculated according to Equation (7), which has been derived for German dry bottom boilers (combustion of hard coal) /71/:

$$EF = 1{,}147 + 0.47 \cdot L \tag{7}$$

EF	emission factor [g/MWh][7]
L	actual load [MW]

At this stage, no general approach is available for estimating the load dependence of NO_x emissions. However, a load correction factor can be obtained by using a ratio between reduced load and full load emission factors:

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[7] 1 MWh = 3.6 GJ

$$k^{load} = \frac{EF^{Reduced\ load}}{EF^{V}} = \frac{1{,}147 + 0.47 \cdot L}{1{,}147 + 0.47 \cdot L_{nominal}} \quad (8)$$

k^{load}	ratio of reduced load to full load emission factor [ ]
$EF^{Reduced\ load}$	emission factor for reduced load conditions [g/MWh]^6
EF^{V}	emission factor for full load conditions [g/MWh]^6
L	actual load [MW]
$L_{nominal}$	nominal load [MW]

Figure 1.1 gives a graphic presentation of the results of Equation (8):

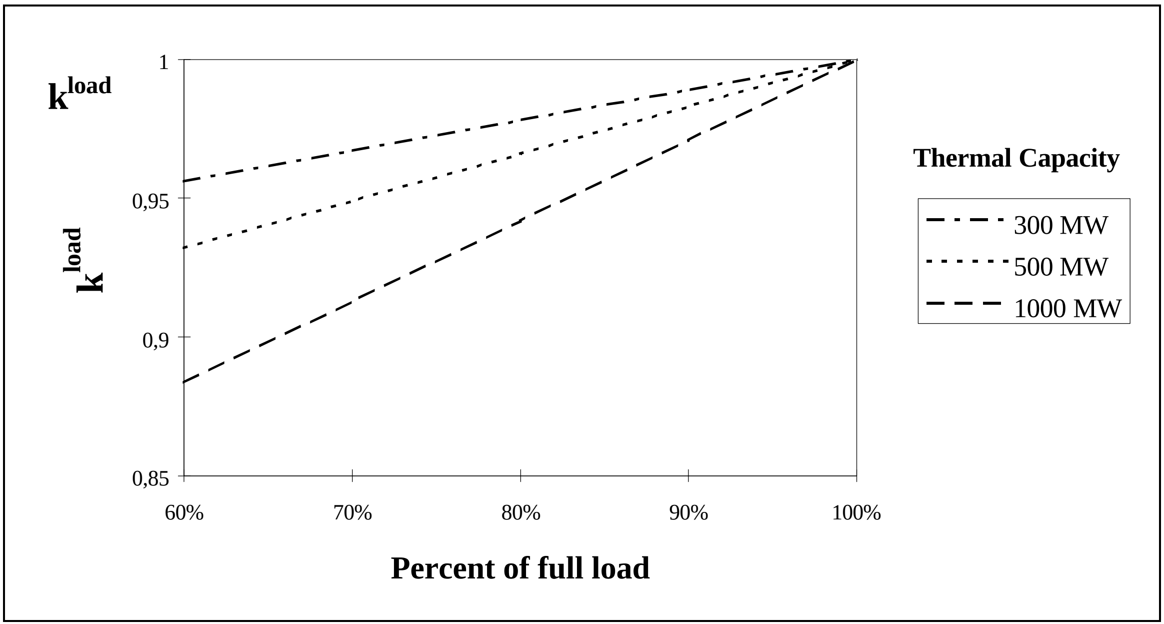


Figure 1.1: Variation of k^{load} with load

If reduced load operation is taken into account the corresponding activity rates have to be determined as follows:

$$A = A_{full\ load} + A_{load\ 1} + A_{load\ 2} + \ldots \quad (9a)$$

A	activity rate within the period considered [GJ]
$A_{full\ load}$	activity rate for full load operation periods [GJ]
$A_{load\ i}$	activity rate for reduced load operation periods at level i [GJ]

Each sub-activity (e.g. $A_{load\ 1}$) has to be determined separately by totalling the thermal energy input for the respective periods of operation e.g. at load level 1.

Emissions are calculated according to Equation (9b):

$$E = EF^{V} \cdot (A_{full\ load} + k^{load\ 1} \cdot A_{load\ 1} + k^{load\ 2} \cdot A_{load\ 2} + ...) \cdot 10^{-6} \qquad (9b)$$

E	emission within the period considered [Mg]
EF^{V}	emission factor at full load conditions [g/GJ]
$A_{load\ i}$	activity rates at load level i [GJ]
$k^{load\ i}$	ratio of reduced load to full load emission factor at load level i [ ]

If secondary measures are installed, no load correction for NO_X emissions has to be taken into account.

b) Load variations with respect to start-up behaviour:

Emission factors for NO_x, as given in Tables 24 and 25, are related to full load conditions; start-up emissions are not taken into account. If an SCR is installed, start-up emissions should be considered as given in Section 4.1.2. The relevance of start-up emissions of NO_x depends strongly on the following parameters:

- the type of boiler (e.g. NO_x emissions released by wet bottom boilers are always higher than those by dry bottom boilers, due to higher combustion temperatures),
- the type of fuel used (e.g. fuel nitrogen also contributes to the formation of NO_x),
- the status of the boiler at starting time (hot, warm or cold start),
- the specifications of any individual start-up, such as
    - -- the duration and the velocity of start-up,
    - -- the load level (reduced load or full load),
    - -- the configuration of secondary measures (e.g. the start-up time of the high-dust-configurations (SCR-precipitator-FGD) depends on the boiler load, due to the fact that the SCR catalyst is directly heated by the flue gas; tail-end-configurations (precipitator-FGD-SCR) can have shorter start-up times, due to the fact that the SCR catalyst can be preheated by an additional furnace),
    - -- emission standards, which have to be met (boiler-specific emission standards can be set up below the demands of the LCP Directive).

In the investigation mentioned in Annex 15 the measured data from different boilers have been analysed. For the combustion of coal the following ratios have been obtained (based on /116/):

- For the combustion of coal in dry bottom boilers the following ranges and values can be given:

Table 12: Ratios of start-up to full load emission factors F^{EF} and ratios of start-up to full load emissions F^{E} for NO_2 for dry bottom boilers

	Ratio of start-up to full load emissions factors F^{EF} [ ]	Ratio of start-up to full load emissions F^{E} [ ]
Range	2 - max. 6	1 - 2
Values for DBB	F^{EF}_{cold} : $3.5-6$ F^{EF}_{warm} : $3-6.5$ F^{EF}_{hot} : $2.5-3$	F^{E}_{cold} : $1.5-2$ F^{E}_{warm} : $1-2$ F^{E}_{hot} : $1-1.5$

$F^{EF}_{cold,warm,hot}$	Ratio of start-up to full load emission factors for cold, warm or hot start-ups (see also Table 6)
$F^{E}_{cold,warm,hot}$	Ratio of start-up to full load emissions for cold, warm or hot start-ups (see also Table 6)

The investigation revealed that start-up emissions of NO_2 were mostly higher than emissions under full load conditions. There is a dependence between start-up emissions (see Section 3.2) and the time of standstill of the boiler: cold starts showed emissions about 2 times higher, warm starts about 1 up to 2 times higher and hot starts about 1 up to 1.5 higher than at full load conditions. Start-up emission factors can be up to 6 times higher than full load emission factors. At the investigated boilers the SCR was installed in a high-dust configuration.

- For the combustion of coal in wet bottom boilers (SCR in tail-end configuration) it was found that start-up emissions were not higher than full load emissions (ratio of ≤ 1). However, this consideration is based on data of only two boilers. Measured data for hot starts was not available.

NO_x emissions, in particular for the combustion of coal in DBB, might be underestimated, if these effects are not taken into account.

4.3.2 Combustion of other fuels (biomass, waste, liquid fuels, gaseous fuels)

The emission calculation is based on Equation (1). During the combustion of solid and liquid fuels, fuel-NO and thermal-NO are formed. For gaseous fuels only thermal-NO_x is relevant, as gaseous fuels do not contain any fuel-nitrogen. For gaseous fuels the emission reduction is mainly achieved by primary measures. There are several biomass-fuelled plants with SNCR in Sweden.

The analysis of emission data from a gas fired boiler, equipped with an SCR, revealed that start-up emissions are not of relevance (ratios F^{E} were below 1) (based on /116/).

4.4 NMVOC/CH_4 emission factors

The emission calculation is based on Equation (1). Fuel and technique specific emission factors are given in Tables 26 and 27.

4.5 CO emission factors

The emission calculation is based on Equation (1). Fuel and technique specific emission factors are given in Table 28 (full load conditions); start-up emissions are not taken into account. CO emissions at starting time and under full load conditions are mainly influenced by the combustion conditions (oxygen availability, oil spraying etc.). In the detailed investigation start-up emissions for CO have only been found to be relevant for the combustion of coal. Start-up emissions for CO are determined for the time when burners switch-on up to the time when the boiler operates on minimum load.

For the combustion of coal and gas the following results have been obtained (based on /116/ see also Section 4.1.2):

- For the combustion of coal in dry bottom boilers the following ranges can be given:

Table 13: Ratios of start-up to full load emission factors F^{EF} and ratios of start-up to full load emissions F^{E} for CO for dry bottom boilers

	Ratios for start-up to full load emission factors F^{EF} [ ]	Ratios for start-up to full load emissions F^{E} [ ]
Range	0.5 - 3.5	0.1 - 0.7
Values for DBB	F^{EF}_{cold} : 1.5 – 3.5 F^{EF}_{warm} : 1 F^{EF}_{hot} : 0.5	F^{E}_{cold} : 0.4 – 0.7 F^{E}_{warm} : 0.2 – 0.7 F^{E}_{hot} : 0.1

$F^{EF}_{cold,warm,hot}$ Ratio of start-up to full load emission factors for cold, warm or hot start-ups (see also Table 6)

$F^{E}_{cold,warm,hot}$ Ratio of start-up to full load emissions for cold, warm or hot start-ups (see also Table 6)

The values in Table 13 show that start-up emissions for CO for DBB are lower than full load emissions for the boilers considered.

- Start-up emissions from wet bottom boilers can be up to 1.2 times higher than full load emissions for cold starts (F^{EF} = 4); they are lower for warm starts (F^{E} = 0.3; F^{EF} = 0.8).

- Start-up emissions of CO from gas boilers are also negligible.

4.6 CO_2 emission factors

The emission calculation is based on Equation (1). Fuel specific emission factors are given in Table 29. For the determination of specified CO_2 emission factors, the following general Equation (10) can be used:

$$EF_{R_{CO2}} = \frac{44}{12} \cdot C_{C_{fuel}} \cdot \varepsilon \cdot \frac{1}{H_u} \cdot 10^6 \qquad (10)$$

$EF_{R_{CO2}}$	specified emission factor [g/GJ]
$C_{C_{fuel}}$	carbon content of fuel (in mass C/mass fuel [kg/kg])
ε	fraction of carbon oxidised [ ]
H_u	lower heating value of fuel [MJ/kg]

Default values for carbon content and lower heating value of different coals, available on the world market, are given in Annexes 7 and 8. The fraction of carbon oxidised (ε) is defined as the main part of carbon which is oxidised to CO_2; small amounts of carbon may remain unoxidised. Default values for ε according to IPCC /61/ are for liquid fuels 0.99, for solid fuels 0.98 and for gaseous fuels 0.995. In this approach it is assumed that the only product of the oxidation is CO_2. Nevertheless, double counting of CO_2 has to be avoided: products of incomplete oxidation, like CO, must not be converted into CO_2.

The IPCC/OECD presented an overall model (the so-called reference approach) specially designed for the calculation of CO_2 emissions on a national level (not on a plant level) /61/. This methodology is based on national energy balances.

4.7 N_2O emission factors

The emission calculation is based on Equation (1). The fuel and technique specific emission factors are given in Table 30. At this stage, several pilot studies using measured data are described in the literature /13, 14, 25, 26, 27/. A complete list of influencing parameters has not yet been identified.

4.8 NH_3 emission factors

Emission factors referring to the energy input are not yet available. The available data for ammonia slip at SCR/SNCR installations are based on measurements and are related to the flue gas volume: SCR/SNCR installations are often designed for an ammonia slip of about 5 ppm (3.8 mg NH_3/m^3 flue gas) /45, 62/. The ammonia slip at SCR and SNCR installations increases with an increasing NH_3/NO_x ratio, but also with a decreasing catalyst activity.

4.9 Heavy metal emission factors

For heavy metals, general and specified emission factors can be used. Emission factors, depending on the fuel used and the technique installed, are given in Table 31.

The IPCC/OECD presented an overall model (the so-called reference approach) specially designed for the calculation of CO_2 emissions on a national level (not on a plant level) /61/. This methodology is based on national energy balances.

4.9.1 Combustion of coal

For an individual determination of specific heavy metal emission factors, three different methodologies can be applied, taking into account:

- fuel composition	(particle-bound and gaseous emissions),
- fly ash composition	(particle-bound emissions),
- fly ash concentration in clean gas	(particle-bound emissions).

The choice of the methodology depends on data availability.

4.9.1.1 Calculation of specified emission factors based on fuel composition /cf. 35/

Emissions of heavy metals associated with particulate matter and gaseous emissions are assessed subsequently as given in Equation (11). The enrichment behaviour of heavy metals with regard to fine particles is taken into account as an enrichment factor (see also Section 3.4). Gaseous emissions have to be taken into account additionally in the case of arsenic, mercury and selenium.

$$EF_{R_{HM}} = C_{HM_{coal}} \cdot f_a \cdot f_e \cdot 10^{-2} \cdot (1 - \eta_p) + C_{HM_{coal}} \cdot f_g \cdot 10^{-2} \cdot (1 - \eta_g) \tag{11}$$

$EF_{R_{HM}}$	specified emission factor of heavy metal (in mass pollutant/mass coal [g/Mg])
$C_{HM_{coal}}$	concentration of heavy metal in coal [mg/kg]
f_a	fraction of ash leaving the combustion chamber as particulate matter [wt.-%]
f_e	enrichment factor [ ]
f_g	fraction of heavy metal emitted in gaseous form [wt.-%]
η_p	efficiency of the dust control equipment [ ]
η_g	efficiency of the emission control equipment with regard to gaseous heavy metals [ ]

The characteristics of fuel and technology are taken into account by f_a and f_e and the following default values are proposed:

Table 14: Default values for f_a for different combustion technologies (based on /35/)

Type of boiler	f_a [wt.-%]
DBB (Pulverised coal)	80
Grate firing	50
Fluidised bed	15

Table 15: Default values for f_e for different heavy metals released by the combustion of coal (based on /35/)

Heavy metal	f_e [ ]	
	range	value[1]
Arsenic	4.5 - 7.5	5.5
Cadmium	6 - 9	7
Copper	1.5 - 3	2.3
Chromium	0.8 - 1.3	1.0
Nickel	1.5 - 5	3.3
Lead	4 - 10	6
Selenium	4 - 12	7.5
Zinc	5 - 9	7

1) Recommended value, if no other information is available.

Gaseous emissions (arsenic, mercury and selenium) are calculated from the heavy metal content in coal; the fraction emitted in gaseous form is given in Table 16. The efficiency of emission control devices with regard to these elements is outlined in Section 3.5.5.

Table 16: Fractions of heavy metals emitted in gaseous form (f_g) released by the combustion of coal /35/

Heavy metal	f_g [wt.-%]
Arsenic	0.5
Mercury	90
Selenium	15

4.9.1.2 Calculation of specified emission factors based on fly ash composition /cf. 39/

If the concentration of heavy metals in raw gas fly ash is known, emission factors of heavy metals can be assessed by Equation (12). Gaseous emissions have to be taken into account separately as outlined in Section 4.9.1.1.

$$EF_{R_{HM,P}} = EF_f \cdot C_{HM_{FA,raw}} \cdot 10^{-3} \cdot (1 - \eta_p) \qquad (12)$$

$EF_{R_{HM,P}}$	specified emission factor of heavy metal in particulate matter (in mass pollutant/mass coal [g/Mg])
EF_f	fly ash emission factor of raw gas (in mass particulate matter/mass coal [kg/Mg])
$C_{HM_{FA,raw}}$	heavy metal concentration in raw gas fly ash (in mass pollutant/mass particulate matter [g/Mg])
η_p	efficiency of dust control equipment [ ]

Values of EF_f can be calculated in a technology specific way using default parameters, as given in Table 17 depending on the content of ash in coal (a) in [wt.-%].

Table 17: Fly ash emission factor for raw gas (EF_f) as function of the ash content in coal (a) [wt.-%] /cf. 39/

Technology	EF_f (in mass particulate matter / mass coal) [kg/Mg]
Cyclone	$1.4 \cdot a$
Stoker	$5.9 \cdot a$
Pulverised coal combustion	$7.3 \cdot a$

The emission factors calculated by taking into account the fuel or the fly ash composition mainly depend on the estimation of the efficiency of dust control equipment.

4.9.1.3 Calculation of specified emission factors based on fly ash concentration in clean flue gas /cf. 36/

If the concentration of heavy metals in fly ash in clean flue gas is known, emission factors of heavy metals can be assessed by Equation (13). Gaseous emissions have to be taken into account separately, as outlined in Section 4.9.1.1.

$$EF_{R_{HM,P}} = C_{HM_{FA,clean}} \cdot C_{FG} \cdot V_{FG} \cdot 10^{-9} \tag{13}$$

$EF_{R_{HM,P}}$	specified emission factor of heavy metal in particulate matter (in mass pollutant/mass coal [g/Mg])
$C_{HM_{FA,clean}}$	concentration of heavy metal in fly ash in clean flue gas (in mass pollutant/mass fly ash [g/Mg])
C_{FG}	concentration of fly ash in clean flue gas (in mass fly ash/volume flue gas [mg/m^3])
V_{FG}	specific flue gas volume (in volume flue gas/ mass coal [m^3/Mg])

Fuel and technology specific heavy metal concentrations in fly ash in clean flue gas ($C_{HM_{FA.clean}}$) are given in Table 18 /36/:

Table 18: Concentration of heavy metals in fly ash in clean flue gas /36/

$C_{HM_{FA.clean}}$	DBB/hc [g/Mg]		WBB/hc [g/Mg]		DBB/hc [g/Mg]	
Heavy metal	range	value	range	value	range	value
As	61 - 528	300	171 - 1,378	690	70 - 120	100
Cd	0.5 - 18	10	18 - 117	80	7 - 12	10
Cr	73 - 291	210	84 - 651	310	10 - 250	70
Cu	25 - 791	290	223 - 971	480	13 - 76	50
Ni	58 - 691	410	438 - 866	650	n. a.	90
Pb	31 - 2,063	560	474 - 5,249	2,210	10 - 202	90
Se1)	18 - 58	45	7 - 8	7	n. a.	n. a.
Zn	61 - 2,405	970	855 - 7,071	3,350	50 - 765	240

1) does not include gaseous Se

n. a.: not available

Default values of particulate matter concentrations downstream of FGD (C_{FG}) are given in Table 19.

Table 19: Particulate matter concentrations downstream of FGD (C_{FG}) released by the combustion of coal based on /18/

Type of FGD	C_{FG} [mg/m^3]	
	range	value1)
WS	20 - 30	25
SDA	20 - 30	25
WL	5 - 10	8
WAP	5 - 10	8
AC	< 40	20
DESONOX	< 40	20

1) Recommended value, if no other information is available.

The concentration of fly ash in flue gas is often monitored continuously. In this case the total annual fly ash emissions can be derived from measured data (see Section 5.2).

4.9.2 Combustion of other fuels

General emission factors for oil and gas combustion can be found in Table 31. Among the other fuels, only waste is relevant for heavy metal emissions. Emission factors for the combustion of waste are currently not available (reported emission factors within the literature mainly refer to the incineration of waste).

5 DETAILED METHODOLOGY

The detailed methodology refers to the handling of measured data in order to determine annual emissions or in order to verify emission factors (for comparison purposes). Annual emissions from major contributors should only be obtained by using continuously measured data which are normally available if secondary abatement technologies are installed. Furthermore, the detailed methodology should be used whenever measured data are available; e.g. for medium and small sized combustion installations periodically measured data are often available.

Measurements are carried out downstream of the boiler or at the stack; measured values obtained by both variants are usable.

National monitoring programmes should include guidelines for quality assurance of measurements (measuring places, methods, reporting procedures, etc.).

The pollutants normally measured at power plants are SO_2, NO_x, CO, and particulate matter. Gaseous emissions of SO_2, NO_x, and CO are treated in Section 5.1. Continuously measured particulate matter emission data can be used to estimate heavy metal emissions (see Section 5.2).

5.1 Gaseous emissions

It is desirable to obtain annual emissions in [Mg]. The annual emission as a function of time is normally given by the following Equation (14):

$$E = \int_T e(t)\, dt \tag{14}$$

E	emission within the period T [Mg]
e (t)	emission per unit of time in the periods of operation [Mg/h]
t	time [h]
T	annual time period (see also Figure 1)

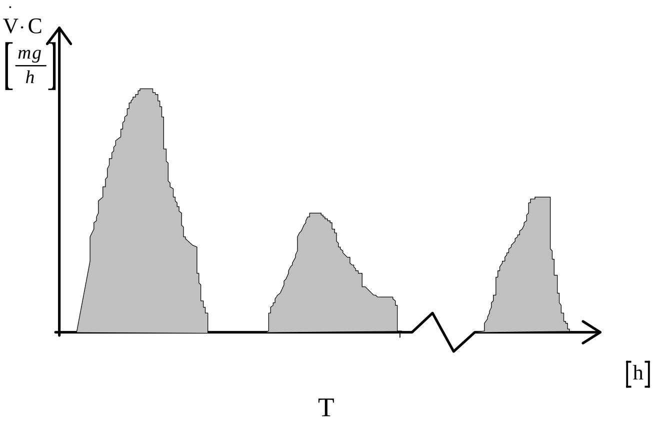
Usually, the emission e(t) cannot be or is not directly measured. Therefore, for practical reasons, the concentration of pollutants and the flue gas volume are used for the determination of e(t), as described by Equation (15):

$$e(t) = \dot{V}(t) \cdot C(t) \tag{15}$$

e (t)	emission in the periods of operation [Mg/h]
$\dot{V}(t)$	flue gas volume flow rate [m^3/h]
C (t)	flue gas concentration of a pollutant [mg/m^3]

Usually, emission fluctuations occur within a year (see Figure 1) as:

- periodical fluctuations (e.g. daily, weekly, seasonally), due to load management depending on the demand of e.g. district heat or electricity,
- operational fluctuations (e.g. start-ups/shut downs, raw material properties, working conditions/reaction conditions).



$\dot{V}$	flue gas volume flow rate [m^3/h]
C	flue gas concentration of a pollutant (abatement techniques installed are included) [mg/m^3]
t	time [h]
t_{bn}	beginning of operation (e.g. start-up of boiler) [h]
t_{en}	ending of operation (e.g. shut down of boiler) [h]
T	annual time period

Figure 1: Periods of operation of a combustion installation

The following approaches can be used to determine annual emissions depending on the level of detail of measured data available.

- First approach:

  The flue gas volume and the concentration of a pollutant are measured continuously (e.g. in Finland). Then, the annual emission is given exactly by the following Equation (16):

$$E = 10^{-9} \int_T \dot{V}(t) \cdot C(t)\, dt \qquad (16)$$

E	emission within the period T [Mg]
$\dot{V}(t)$	flue gas volume flow rate [m^3/h]
C (t)	flue gas concentration of a pollutant (abatement techniques installed are included) [mg/m^3]
t	time [h]
T	annual time period (see also Figure 1)

The precision of measurements of $\dot{V}(t)$ and C(t) depends on the performance of the analytical methods (e.g. state-of-the-art) used. In particular, the regular calibration of measuring instruments is very important. Analytical methods commonly used for NO_x detect only NO and those used for SO_x detect only SO_2. It is implicitly assumed that NO_2 in the flue gas is normally below 5 %, and that SO_3 in the flue gas is negligible. Nevertheless, for some combustion plants the amounts of NO_2 and/or SO_3 formed can be significant and have to be detected by appropriate analytical methods. The measured values have to be specified with regard to dry/wet flue gas conditions and standard oxygen concentrations[8].

For the annual time period T considered, a case distinction has to be made:

- calendar year T_1 (e.g. including time out of operation),
- real operating time T_2 of boiler/plant (e.g. start-ups are reported when „burner on/off"),
- official reporting time T_3 determined by legislation (e.g. start-ups are reported, as soon as the oxygen content in the flue gas goes below 16 %),

where $T_3 \subset T_2 \subset T_1$. If C(t) is only available for T_3, adequate corrections have to be provided.

– Second approach:

Due to the difficulty in measuring V(t) continuously in large diameter stacks, in most cases the flue gas volume flow rate V(t) is not measured. Then the annual emission can be determined by Equation (17):

$$E = 10^{-9}\, \overline{\dot{V}} \int_T C(t)\, dt \tag{17}$$

E	emission within the period T [Mg]
$\overline{\dot{V}}$	average flue gas volume flow rate [m^3/h]
C(t)	flue gas concentration of a pollutant (abatement techniques installed are included) [mg/m^3]
t	time [h]
T	annual time period (see also Figure 1)

The average flue gas volume flow rate $\overline{\dot{V}}$ (dry conditions) can be determined according to the following Equations (18) and (19):

$$\overline{\dot{V}} = V_{FG} \cdot \dot{m}_{fuel} \tag{18}$$

$\overline{\dot{V}}$	average flue gas volume flow rate [m^3/h]
V_{FG}	dry flue gas volume per mass fuel [m^3/kg]
$\dot{m}_{fuel}$	fuel consumption rate [kg/h]

$$V_{FG} \approx 1.852\left[\tfrac{m^3}{kg}\right] \cdot C_c + 0.682\left[\tfrac{m^3}{kg}\right] \cdot C_s + 0.800\left[\tfrac{m^3}{kg}\right] \cdot C_N + V_{N_{air}} \tag{19}$$

V_{FG}	dry flue gas volume per mass fuel [m^3/kg]
C_c	concentration of carbon in fuel [kg/kg]
C_s	concentration of sulphur in fuel [kg/kg]
C_N	concentration of nitrogen in fuel [kg/kg]
$V_{N_{air}}$	specific volume of air nitrogen (in volume/mass fuel [m^3/kg])

---

[8] In some countries the measured values obtained are automatically converted into values under standard oxygen concentrations (e.g. in Germany).

This calculation of V according to Equation (19) can be performed by the computer programme (see Annex 6) by using default values for C_C, C_S, C_N and $V_{N_{air}}$.

- Third approach:
  In some countries the term $\int_T C(t)\,dt$ is available as an annual density function P(C) (histogram). In this case Equation (17) can be simplified to:

$$E = \bar{\dot{V}} \cdot \bar{C} \cdot t_{op} \cdot 10^{-9} \qquad (20)$$

$$\text{where} \quad \bar{C} = \int_0^\infty P(C) \cdot C \cdot dC \qquad (21)$$

E	emission within the period T [Mg]
$\bar{\dot{V}}$	average flue gas volume flow rate [m^3/h]
$\bar{C}$	expected value (mean value) of the flue gas concentration for each pollutant (abatement techniques installed are included) [mg/m^3]
t_{op}	annual operating time [h]
P(C)	density function [ ]
C	flue gas concentration per pollutant as given in the histogram [mg/m^3]

The variable t_{op} has to be introduced consistently with $\bar{\dot{V}}$ and $\bar{C}$ according to periods T_1, T_2 or T_3 mentioned above. If e.g. start-ups are not included, they should be taken into account as given in Sections 4.1, 4.2 and 4.4.

- Fourth approach:
  If neither T_2 nor T_3 are available, the annual full load operating hours can also be used. Then Equation (20) becomes:

$$E = \bar{\dot{V}}_{normed} \cdot \bar{C} \cdot t_{op}^{full\ load} \cdot 10^{-9} \qquad (22)$$

E	emission within the period considered [Mg]
$\bar{\dot{V}}_{normed}$	average flue gas volume flow rate related to full load operation [m^3/h]
$\bar{C}$	mean value of the flue gas concentration for each pollutant (abatement techniques installed are included) [mg/m^3]
$t_{op}^{full\,load}$	annual operating time expressed as full load operating hours [h]

From here, emission factors, based on measured values, can be derived e.g. for verification purposes:

$$EF = \frac{E}{A} \cdot 10^6 \qquad (23)$$

EF	emission factor [g/GJ]
E	emission within the period considered [Mg]
A	activity rate within the time period considered [GJ]

5.2 Heavy metal emissions

Continuously measured values for the total heavy metal emissions (particle-bound and gaseous) are not available for the combustion of fossil fuels. National legislation can require periodical measurements, e.g. weekly measurements of heavy metal emissions [mg/m^3] in the case of waste incineration/combustion.

The emissions of particle-bound heavy metals depend on the emission of particulate matter which is normally periodically or continuously monitored. Therefore, the particle-bound heavy metal emissions can be derived from the element content in particulate matter. The heavy metal emission factor can be back-calculated as follows:

$$EF = \frac{\overline{\dot{m}}_{FA} \cdot \overline{C}_{HM_{FA.clean}}}{A} \tag{24}$$

EF	emission factor [g/GJ]
$\overline{\dot{m}}_{FA}$	mass of fly ash within the period considered [Mg]
$\overline{C}_{HM_{FA.clean}}$	average concentration of heavy metal in fly ash (in mass pollutant/mass fly ash [g/Mg])
A	activity rate within the period considered [GJ]

Measured data should also be used to replace the default values of Equation (13) for $C_{HM_{FA.clean}}$ and C_{FG}.

6 RELEVANT ACTIVITY STATISTICS

In general, the published statistics do not include point sources individually. Informations on this level should be obtained directly from each plant operator.

On a national level, statistics can be used for the determination of fuel consumption, installed capacity and/or types of boilers mainly used. The following statistical publications can be recommended:

- Office for Official Publication of the European Communities (ed.): Annual Statistics 1990; Luxembourg 1992
- Commission of the European Communities (ed.): Energy in Europe - Annual Energy Review; Brussels 1991
- Statistical Office of the European Communities (EUROSTAT) (ed.): CRONOS Databank, 1993
- OECD (ed.): Environmental Data, Données OCDE sur l’environnement; compendium 1993
- Commission of the European Communities (ed.): Energy in Europe; 1993 - Annual Energy Review; Special Issue; Brussels 1994
- EUROSTAT (ed.): Panorama of EU Industry’94; Office for official publications of the European Communities; Luxembourg 1994

7 POINT SOURCE CRITERIA

Point source criteria for a combustion plant according to CORINAIR are given in chapter AINT and in /41/.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

Tables 23 - 31 list emission factors for all pollutants considered, except for SO_2. For SO_2 emission factors have to be calculated individually (see Equation (5)). Sulphur contents of different fuels are given. The emission factors have been derived from the literature, from the calculations presented here (see also Section 4) and from recommendations from expert panel members. All emission factor tables have been designed in a homogenous structure: Table 20 contains the allocation of SNAP activities used related to combustion installations, where three classes are distinguished according to the thermal capacity installed. Table 21 includes the main types of fuel used within the CORINAIR90 inventory. Table 22 provides a split of combustion techniques (types of boilers, etc.); this standard table has been used for all pollutants. The sequence of the emission factor tables is:

Table 20: SNAP code and SNAP activity related to the thermal capacities installed in combustion plants

Table 21: Selection of relevant fuels from NAPFUE and lower heating values for boilers, gas turbines and stationary engines

Table 22: Standard table for emission factors for the relevant pollutants

Table 23: S-contents of selected fuels

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

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

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

Table 27: CH_4 emission factors [g/GJ] for combustion plants

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

Table 29: CO_2 emission factors [kg/GJ] for combustion plants

Table 30: N_2O emission factors [g/GJ] for combustion plants

Table 31: Heavy metal emission factors [g/Mg] for combustion plants

References of the emission factors listed are given in footnotes of the following tables. Quality codes are not available in the literature.

Table 20: SNAP code and SNAP activity related to the thermal capacities installed in combustion plants

Thermal capacity [MW]	SNAP code	SNAP activity
>= 300	010101	Public power and co-generation combustion plants
	010201	District heating combustion plants
	010301	Petroleum and/or gas refining plants
	010401	Solid fuel transformation plants
	010501	Coal mining, oil, gas extraction/distribution plants
	020101	Commercial and institutional plants
	030101	Industrial combustion plants
>=50 up to < 300	010102	Public power and co-generation combustion plants
	010202	District heating combustion plants
	020102	Commercial and institutional plants
	020201	Residential combustion plants
	020301	Plants in agriculture, forestry and fishing
	030102	Industrial combustion plants
< 50	010103	Public power and co-generation combustion plants
	010203	District heating combustion plants
	020103	Commercial and institutional plants
	020202	Residential combustion plants
	020302	Plants in agriculture, forestry and fishing
	030103	Industrial combustion plants

Table 21: Selection of relevant fuels from NAPFUE and lower heating values for boilers, gas turbines and stationary engines

Type of fuel according to NAPFUE					NAPFUE code	H_u [MJ/kg][2]
s	coal	hc	coking [1]	GHV[11] > 23,865 kJ/kg	101	29.3[4]
s	coal	hc	steam [1]	GHV[11] > 23,865 kJ/kg	102	29.3[4]
s	coal	hc	sub-bituminous	17,435 kJ/kg < GHV[11] < 23,865 kJ/kg	103	20.6
s	coal	hc/bc	patent fuels	from hard/sub-bituminous coal	104	
s	coal	bc	brown coal/lignite	GHV[11] < 17,435 kJ/kg	105	12.1
s	coal	bc	briquettes		106	19.5[4]; 18.6[5]
s	coke	hc	coke oven		107	26.3[10]
s	coke	bc	coke oven		108	29.9[7]
s	coke		petroleum		110	30[10]
s	biomass		wood		111	12.4[4], 16[10]
s	biomass		charcoal		112	
s	biomass		peat		113	9.5[10]
s	waste		municipal		114	7.5[4]
s	waste		industrial		115	8.4[8]
s	waste		wood	except wastes similar to wood	116	
s	waste		agricultural	corncobs, straw etc.	117	
l	oil		residual		203	41.0[4]
l	oil		gas		204	42.7[4], 42.5[10]
l	oil		diesel	for road transport	205	
l	kerosene				206	
l	gasoline		motor		208	43.5[4]
l	naphtha				210	
l	black liquor				215	
g	gas		natural	except liquified natural gas	301	heavy 39.7 MJ/m^3 [3], light 32.5 MJ/m^3 [3]
g	gas		liquified petroleum gas		303	45.4[10]
g	gas		coke oven		304	19.8[10]
g	gas		blast furnace		305	3.0[10]
g	gas		coke oven and blast furnace gas		306	
g	gas		waste		307	
g	gas		refinery	not condensable	308	48.4[6], 87 MJ/m^3 [10]
g	gas		biogas		309	34.7[9]
g	gas		from gas works		311	

[1] A principal differentiation between coking coal and steam coal is given in section 3.2. Further differentiation between coking coal and steam coal can be made by using the content of volatiles: coking coal contains 20 - 30 wt.-% volatiles (maf), steam coal contains 9.5 - 20 wt.-% volatiles (maf) (based on official UK subdivision). This is necessary if no information concerning the mean random reflectance of vitrinite (see Section 3.2) is available.

[2] H_u = lower heating value; lower heating values for coals from different countries are given in Annexes 7 and 8 and for solid, liquid and gaseous fuels in (/88/, Table 1-2).

[3] given under standard conditions

[4] Kolar 1990 /17/

[5] /98/

[6] MWV 1992 /97/

[7] Boelitz 1993 /78/

[8] Schenkel 1990 /105/

[9] Steinmüller 1984 /107/

[10] NL-handbook 1988 /99/

[11] GHV = Gross heating value

Table 22: Standard table of emission factors for the relevant pollutants

Type of fuel[1]			NAPFUE code[1]	H_u[2] [MJ/kg]	P1[3]	Thermal boiler capacity [MW][4]																				no specification
						>= 300			>= 50 and < 300						< 50											
						Type of boiler			Type of boiler						Type of boiler							GT[10]		Stat. E.[11]		CORINAIR90[12]
						DBB[5]	WBB[6]	FBC[7]	DBB	WBB	FBC[7]		GF[8]		DBB	WBB	FBC[7]			GF						
						Primary measures[9]	Primary measures[9]	CFBC			CFBC	PFBC	ST1	ST2			AFBC	CFBC	PFBC	ST1	ST2	SC	CC	CI	SI	
s	coal	hc																								
s	coal	hc																								
s	coal	hc																								
s	coal	bc	...	...	...																					
s	coke																									
s	biomass																									
s	waste																									
l	oil																									
g	gas																									

[1] the type of fuel is based on the NAPFUE code, see table 21

[2] H_u = lower heating value, when different from table 21

[3] relevant parameter of fuel composition for SO_2: P1 = sulphur content of fuel;

[4] the corresponding SNAP-codes are listed in table 20

[5] DBB - Dry bottom boiler

[6] WBB - Wet bottom boiler

[7] FBC - Fluidised bed combustion; CFBC = Circulating FBC; PFBC = Pressurised FBC (Dense FBC); AFBC = Atmospheric FBC

[8] GF - Grate firing; ST1 and ST2 are different types of stoker (e.g. travelling stoker, spreader stoker)

[9] Primary measures are described by reduction efficiency

[10] GT = Gas turbine; SC = Simple cycle; CC = Combined cycle

[11] Stat. E. = Stationary engine; CI = Compression ignition; SI = Spark ignition

[12] CORINAIR90 data on combustion plants as point sources

Table 23: S-contents of selected fuels 1)

Type of fuel				NAPFUE code	Sulphur content of fuel value 2)	range	unit
s	coal 3)	hc	coking	101		0.4 - 6.2	wt.-% (maf)
s	coal 3)	hc	steam	102		0.4 - 6.2	wt.-% (maf)
s	coal 3)	hc	sub-bituminous	103		0.4 - 6.2	wt.-% (maf)
s	coal 3)	bc	brown coal/lignite	105		0.4 - 6.2	wt.-% (maf)
s	coal	bc	briquettes	106		0.25 - 0.45 13)	wt.-% (maf)
s	coke	hc	coke oven	107		< 1 5)	wt.-% (maf)
s	coke	bc	coke oven	108		0.5 - 1 5) 6)	wt.-% (maf)
s	coke		petroleum	110			
s	biomass		wood	111		< 0.03 5)	wt.-% (maf)
s	biomass		charcoal	112		< 0.03 5)	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 8) - 3.5 9)	wt.-%
l	oil		gas	204	0.3 11)	0.08 - 1.0	wt.-%
l	oil		diesel	205	0.3 11)		wt.-%
l	kerosene			206			
l	gasoline		motor	208		< 0.05 12)	wt.-%
l	naphtha			210			
l	black liquor			215			
g	gas 4)		natural	301	(0.0075) 10)		$g \cdot m^{-3}$
g	gas		liquified petroleum gas	303	-		
g	gas		coke oven	304	8		$g \cdot m^{-3}$
g	gas		blast furnace	305	$45 \cdot 10^{-3}$ 10)		$g \cdot m^{-3}$
g	gas		coke oven and blast furnace gas	306			
g	gas		waste	307			
g	gas		refinery	308		<= 8 10)	$g \cdot m^{-3}$
g	gas		biogas	309			
g	gas		from gas works	311			

1) for emission factor calculation see Section 4.1, and Annexes 2 and 3

2) recommended value

3) for complete coal composition see Annexes 7 and 8

4) only trace amounts

5) Marutzky 1989 /94/

6) Boelitz 1993 /78/

8) Mr. Hietamäki (Finland): Personal communication

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

10) NL-handbook 1988 /99/

11) 87/219 CEE 1987 /113/

12) $\alpha_s \sim 0$

13) Davids 1986 /46/

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 gas	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					

to be continued

Table 24: continued

Thermal boiler capacity [MW]													no speci-fication 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]			70[1]		150[1]					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[15]	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]
			140[1,29], 180[1,30]						250[45]		1,090-1,200[45]		24 - 370[44]
			80[1], 100[1]						120 [1,35], 350[1,33], 380[1,34], 780[1,36]		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]
			100[1], 48 - 333[22,23,24]						150 - 360[45]		600[1,37,42], 1,200[1,38,42]	1,000[1,40,42], 1,800[1,39,42]	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
						η= 0	η= 0.20	η=0.45	η=0.45	η=0.60	η= 0	η= 0.20	η=0.45	η=0.40	η=0.60
s	coal	hc	Australia	(101)	34	568	454	312	312	227	703	562	387	422	281
			Canada	(101)	33	500	405	278	278	202	627	501	345	376	251
			China	(101)	32	413	331	227	227	165	512	409	281	307	205
			Columbia	(101)	32	535	428	394	394	214	662	529	364	397	265
			Czech Republic	(101)	34	483	387	266	266	193	598	479	329	359	239
			France	101	35	374	299	205	205	149	463	370	254	278	185
			Germany RAG	102	35	384	307	211	211	154	476	381	262	285	190
			Germany others	101	30	495	396	272	272	198	613	490	337	368	245
			CIS	(101)	32	308	247	169	169	123	382	305	210	229	153
			Hungary	101	34	401	320	220	220	160	496	397	273	298	198
			India	103	30	551	441	303	303	220	682	545	375	409	273
			South Africa	(101)	32	569	456	313	313	228	705	504	388	423	282
			USA	(101)	34	563	450	310	310	225	697	558	383	418	279
			Venezuela	(101)	34	588	471	324	324	235	728	583	401	437	291
						η= 0	η= 0.20	η=0.45	η=0.40	η=0.60					
s	coal	bc	Czech Republic	105	28	506	405	278	304	202					
			Germany												
			- Rheinisch Coal	105	27	325	260	179	195	130					
			- Middle Germany	105	25	504	403	277	302	202					
			- East Germany	105	26	539	431	296	323	215					
			Hungary-1	105	36	379	303	208	227	151					
			Hungary-2	103	28	379	304	209	228	152					
			Poland	105	25	531	425	292	319	213					
			Portugal	105	25	461	369	254	277	185					
			Turkey-2	103	27	725	580	399	435	290					

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

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

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

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

Type of fuel				NAPFUE code	Thermal boiler capacity [MW]					no specification CORINAIR90[6]
					>= 50		< 50			
					boiler	GF	boiler	Gas turbine	Stationary engine	
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 27: CH_4 emission factors [g/GJ] for combustion plants

					Type of combustion										stat. E.	no specification
					Utility combustion			Commercial comb.		Industrial combustion						
Tpe of fuel				NAPFUE code	DBB/WBB FBC/ boiler$^{3)}$	GF stoker		boiler	GF	boiler	GF stoker		GT			CORINAIR90$^{5)}$
						spreader	travell.				spreader	travell.	SC	CC		
s	coal	hc	coking	101	0.6$^{1)}$	0.7$^{1)}$		10$^{1)}$		2.4$^{1)}$						0.3 - 15$^{5)}$
s	coal	hc	steam	102	0.6$^{1)}$	0.7$^{1)}$		10$^{1)}$		2.4$^{1)}$						1.5 - 15$^{5)}$
s	coal	hc	sub-bituminous	103	0.6$^{1)}$	0.7$^{1)}$		10$^{1)}$		2.4$^{1)}$						0.3 - 15$^{5)}$
s	coal	bc	brown coal/lignite	105	0.6$^{1)}$	0.7$^{1)}$		10$^{1)}$		2.4$^{1)}$						
s	coal	bc	briquettes	106												
s	coke	hc	coke oven	107												0.2 - 15$^{5)}$
s	coke	bc	coke oven	108												
s	coke		petroleum	110												1.5$^{5)}$
s	biomass		wood	111	18$^{1)}$			15$^{1)}$		15$^{1)}$						1 - 40$^{5)}$
s	biomass		charcoal	112												
s	biomass		peat	113												1 - 39$^{5)}$
s	waste		municipal	114				6.5$^{1),4)}$								1$^{5)}$
s	waste		industrial	115												10$^{5)}$
s	waste		wood	116												4 - 40$^{5)}$
s	waste		agricultural	117				9$^{1),4)}$								32$^{5)}$
l	oil		residual	203	0.7$^{1)}$			1.6$^{1)}$		2.9$^{1)}$			3$^{5)}$		3$^{6)}$	0.1 - 10$^{5)}$
l	oil		gas	204	0.03$^{1)}$			0.6$^{1)}$					1 - 8$^{5)}$		1.5$^{6)}$	0.1 - 8$^{5)}$
l	oil		diesel	205												
l	kerosene			206												7$^{5)}$
l	gasoline		motor	208												
l	naphtha			210												3$^{5)}$
l	black liquor			215												1 - 17.7$^{5)}$
g	gas		natural	301	0.1$^{1)}$			1.2$^{1)\ 2)}$		1.4$^{1)}$			2.5 - 4$^{6)}$ 5.9$^{1)}$	6.1$^{1)}$		0.3 - 4$^{5)}$
g	gas		liquified petroleum gas	303												1 - 2.5$^{5)}$
g	gas		coke oven	304												0.3 - 4$^{5)}$
g	gas		blast furnace	305												0.3 - 2.5$^{5)}$
g	gas		coke oven and blast furnace gas	306												
g	gas		waste	307												2.5$^{5)}$
g	gas		refinery	308												0.1 - 2.5$^{5)}$
g	gas		biogas	309									2.5$^{6)}$			0.5 - 2.5$^{5)}$
g	gas		from gas works	311												

[1] Radian 1990 /102/, IPCC 1994 /88/ [2] for all types of gas [3] DBB/WBB/FBC for coal combustion; boiler for fuel combustion [4] open burning

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

[6] CORINAIR90 data, point sources

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

			Type of fuel	NAPFUE code	Type of combustion								GT	stat. E.	no specification CORINAIR90 9)
					Utility combustion			Commercial comb.		Industrial combustion					
					DBB/WBB/ boilers 1)	GF stoker		boiler	GF	DBB/WBB/ boiler 1)	GF stoker				
						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)			15 9)
s	coal	hc	steam	102	14 3)	121 3)		195 3)		9.7 2), 13 4)	115 4)	9.7 2)			10 - 175.2 9)
s	coal	hc	sub-bituminous	103	14 3)	121 3)		195 3)		9.7 2), 13 4)	81 2), 115 4)	97.2 2)			12 - 246.9 9)
s	coal	bc	brown coal/lignite	105	14 3)	121 3)		195 3)		16 2), 13 4)	133 2), 115 4)	160 2)			9.6 - 64.4 9)
s	coal	bc	briquettes	106											
s	coke	hc	coke oven	107											102 - 121 9)
s	coke	bc	coke oven	108											
s	coke		petroleum	110											15 9)
s	biomass		wood	111	1,473 3)			199 3)		1,504 3)					30 - 300 9)
s	biomass		charcoal	112											
s	biomass		peat	113											30 - 160 9)
s	waste		municipal	114		98 3),6)		19 3)			19 3)7), 96 3)7), 42 kg/Mg 3),8)				30 9)
s	waste		industrial	115											
s	waste		wood	116											12 - 300 9)
s	waste		agricultural	117				58 kg/Mg 3),8)							20 9)
l	oil		residual	203	15 3)			17 3)		15 3)			10 - 15 10)	100 10)	3 - 32.6 9)
l	oil		gas	204	15 3)			16 3)		12 3)			10 - 20 10) 20.6 11)	12 - 1,130 10)	10 - 46.4 9)
l	oil		diesel	205											
l	kerosene			206											12 9)
l	gasoline		motor	208											
l	naphtha			210											15 9)
l	black liquor			215											11.1 - 314 9)
g	gas		natural	301	19 3)			9.6 3)		17 3), 13 5)				10 - 20 10), 32 3)	0.05 - 60 9)
g	gas		liquified petroleum gas	303											10 - 13 9)
g	gas		coke oven	304											0.03 - 130 9)
g	gas		blast furnace	305											0.3 - 64.4 9)
g	gas		coke oven and blast furnace gas	306											
g	gas		waste	307											0.1 - 25.5 9)
g	gas		refinery	308										10 10)	2 - 15 9)
g	gas		biogas	309											13 9)
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/

Table 29: CO_2 emission factors [kg/GJ] for combustion plants

Type of fuel				NAPFUE	Emission factors		
				code	value	range	remarks
s	coal	hc	coking	101		92 - 93 [5], 89.6 - 94[2]	
s	coal	hc	steam	102	93.7 [3], 92 [5]	92 - 93 [5], 10 - 98[2]	
s	coal	hc	sub-bituminous	103	94.7 [3]	91 - 115.2[2]	
s	coal	bc	brown coal/lignite	105	100.2 [3]	94 - 107.9[2], 110 - 113[5]	
s	coal	bc	briquettes	106	98	97 - 99[5]	
s	coke	hc	coke oven	107	95.9 [4], 108 [1]	100 - 105[5], 105 - 108[2]	
s	coke	bc	coke oven	108		96 - 111[5]	
s	coke		petroleum	110	101[5], 121.2 [4], 100.8[2]		
s	biomass		wood	111	100 [1], 124.9 [4]	92 - 100[2]	
s	biomass		charcoal	112			
s	biomass		peat	113	98[5]	102 - 115[2]	
s	waste		municipal	114	15 [5], 28[2]	109 - 141[1]	
s	waste		industrial	115		13.5 - 20 [5]	
s	waste		wood	116		83 - 100[2]	
s	waste		agricultural	117			
l	oil		residual	203	75.8 [4], 76.6 [3], 78 [5]	15 - 93[2]	petroleum oil 72.6 [3]
l	oil		gas	204	72.7 [4], 74 [5], 75 [1]	73 - 74 [5], 57 - 75[2]	
l	oil		diesel	205	72.7 [4], 73[5]		
l	kerosene			206	73.3[2]	72 - 74[5]	
l	gasoline		motor	208	70.8 [3], 71.7 [4], 72.2 [1]	72 - 74[5]	
l	naphtha			210	72.6 [3], 74[2]		
l	black liquor			215		100 - 110[2]	
g	gas		natural	301	55.5 [3], 60.8 [4]	55 - 56 [5], 44 - 57[2]	
g	gas		liquified petroleum gas	303		64 - 65[5], 57 - 65[2]	
g	gas		coke oven	304	44 [5]	44 - 49[5], 41.6 - 90[2]	
g	gas		blast furnace	305	105 [5]	100 - 105[5], 92 - 280[2]	
g	gas		coke oven and blast furnace gas	306			
g	gas		waste	307		44.4 - 57[2]	
g	gas		refinery	308	60 [5]		
g	gas		biogas	309	75[2]	10.5 - 73.3[2]	
g	gas		from gas works	311	52[2]		

(1) Schenkel 1990 /105/

(2) CORINAIR90 data on combustion plants as point sources with thermal capacity of > 300, 50 - 300, < 50 MW

(3) IPCC 1993 /87/

(4) Kamm 1993 /89/

(5) BMU 1994 /77/

Table 30: N_2O emission factors [g/GJ] for combustion plants

					Type of boiler										
Type of fuel				NAPFUE code	DBB		WBB		FBC		GF		GT	stat. E.	no specification CORINAIR90[4)]
					value	remarks	value	remarks	value	remarks	value	remarks			
s	coal	hc	coking	101	0.8[1)]	utility, no PM[3)]	0.8[1)]	utility, no PM[3)]			0.8[1)]	utility, no PM[3)]			14[4)]
s	coal	hc	steam	102	0.8[1)]	utility, no PM[3)]	0.8[1)]	utility, no PM[3)]			0.8[1)]	utility, no PM[3)]			2.5 - 100[4)]
s	coal	hc	sub-bituminous	103	0.8[1)]	utility, no PM[3)]	0.8[1)]	utility, no PM[3)]			0.8[1)]	utility, no PM[3)]			2.5 - 30[4)]
s	coal	bc	brown coal/lignite	105	0.8[1)]	utility, no PM[3)]					0.8[1)]	utility, no PM[3)]			1.4 - 30[4)]
s	coal	bc	briquettes	106											
s	coke	hc	coke oven	107											1.4 - 25[4)]
s	coke	bc	coke oven	108											
s	coke		petroleum	110											14[4)]
s	biomass		wood	111	4.3[1)]	commercial, no PM[3)]			4.3[1)]	commercial, no PM[3)]	4.3[1)]	commercial, no PM[3)]			1.4 - 75[4)]
s	biomass		charcoal	112											
s	biomass		peat	113											2 - 75[4)]
s	waste		municipal	114					14 - 165[2)]	g/t waste	11 - 270[2)]	g/t waste			4[4)]
s	waste		industrial	115											1.4[4)]
s	waste		wood	116											2 - 6[4)]
s	waste		agricultural	117											5[4)]
l	oil		residual	203	46.5[1)]	commercial, no PM[3)]							2.5 - 14[5)]	2.5[5)]	1.4 - 14.8[4)]
l	oil		gas	204	15.7[1)]	commercial, no PM[3)]							2 - 3[5)]	2.5[5)]	0.6 - 14[4)]
l	oil		diesel	205											
l	kerosene			206											14[4)]
l	gasoline		motor	208											
l	naphtha			210											14[4)]
l	black liquor			215											1 - 21.4[4)]
g	gas		natural	301	2.4[1)]	commercial, no PM[3)]								1 - 3[5)]	0.1 - 3[4)]
g	gas		liquified petroleum gas	303											2 - 4.3[4)]
g	gas		coke oven	304											1.1 - 3[4)]
g	gas		blast furnace	305											1.1 - 3[4)]
g	gas		coke oven and blast furnace	306											
g	gas		waste	307											1.1 - 2.5[4)]
g	gas		refinery	308										2.5[5)]	2.5 - 14[4)]
g	gas		biogas	309											1.4 - 2.5[4)]
g	gas		from gas works	311											

[1)] Radian 1990 /102/, IPCC 1994 /88/ [2)] DeSoete 1993 /83/, IPCC 1994 /88/ [3)] PM: Primary measure [5)] CORINAIR90 data, point sources

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

Table 31: Heavy metal emission factors (g/Mg fuel) for combustion plants

					Thermal boiler capacity [MW]								
					>= 300				>= 50 and < 300				< 50
					Type of boiler				Type of boiler				
Type of fuel			NAPFUE code	Heavy metal element	DBB		WBB		DBB	WBB	FBC	GF	GF
					Dust control [1]	Dust control and FGD [2]	Dust control [1]	Dust control and FGD [2]					
s	coal	hc	101/102	Mercury	0.05 - 0.2	0.02 - 0.08	0.05 - 0.2	0.02 - 0.08					
				Cadmium	0.003 - 0.01	0.0001 - 0.004	0.01 - 0.07	0.004 - 0.03					
				Lead	0.02 - 1.1	0.007 - 0.5	0.3 - 3	0.1 - 1.2					
				Copper	0.01 - 0.4	0.006 - 0.2	0.05 - 0.4	0.05 - 0.2					
				Zinc	0.03 - 1.3	0.01 - 0.5	0.5 - 4	0.2 - 1.6					
				Arsenic	0.03 - 0.3	0.01 - 0.1	0.1 - 0.8	0.04 - 0.3					
				Chromium	0.04 - 0.2	0.02 - 0.06	0.05 - 0.4	0.02 - 0.2					
				Selen	0.01 - 0.03	0.004 - 0.01	-	-					
				Nickel	0.03 - 0.4	0.01 - 0.5	0.2 - 0.5	0.1 - 0.2					
s	coal	bc	105	Mercury	0.05 - 0.2	0.02 - 0.08	╳	╳		╳		╳	╳
				Cadmium	0.002 - 0.004	0.0008 - 0.001							
				Lead	0.003 - 0.06	0.001 - 0.02							
				Copper	0.004 - 0.02	0.002 - 0.01							
				Zinc	0.01 - 0.2	0.006 - 0.1							
				Arsenic	0.03 - 0.04	0.008 - 0.01							
				Chromium	0.003 - 0.07	0.001 - 0.03							
				Selen	-	-							
				Nickel	0.02 - 0.04	0.01							
l	oil, heavy fuel		203	Mercury	1.0[4]		╳	╳		╳	╳	╳	╳
				Cadmium	1.0[4]								
				Lead	1.3[4]								
				Copper	1.0[4]								
				Zinc	1.0[4]								
				Arsenic	0.5[4]								
				Chromium	2.5[4]								
				Selen									
				Vanadium	4.4[5]								
				Nickel	35[4]								
g	gas, natural		301	Mercury	0.05 - 0.15 g/TJ[3]		╳	╳		╳	╳	╳	╳

[1] clean gas particle concentration 50 mg/m

[2] FGD = Flue gas desulphurisation, clean gas particle concentration 20 mg/m^3

[3] 2 mg/m^3 gas UBA 1980 /63/; 5 mg/m^3 PARCOM 1992 /101/

[4] general emission factor according to Stobbelaar 1992 /37/

[5] Jockel 1991 /36/

9 SPECIFIC PROFILES

9.1 SO_x emissions

Sulphur dioxide SO_2 and sulphur trioxide SO_3 are formed in the flame. Emissions of SO_2 and SO_3 are often considered together as SO_x. Due to the equilibrium conditions at furnace temperature, sulphur trioxide SO_3 normally decomposes to sulphur dioxide SO_2. Then the amount of SO_2 in the flue gas is approximately 99 %. Therefore, SO_x is given in this chapter as SO_2.

9.2 NO_x emissions

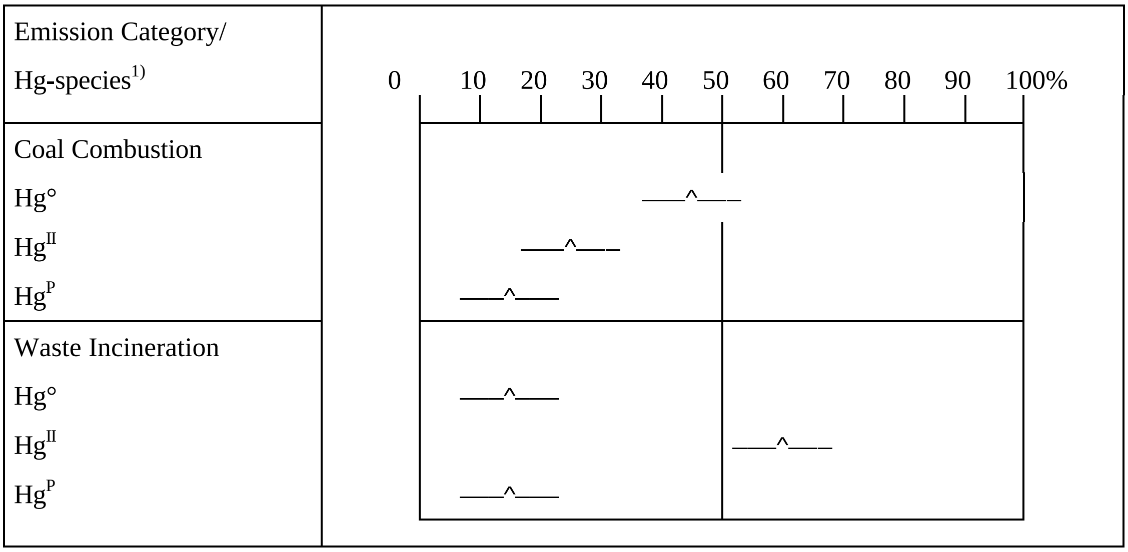
The most important oxides of nitrogen formed with respect to pollution are nitric oxide (NO) and nitrogen dioxide (NO_2), jointly referred to as NO_x. The main compound is NO, which contributes over 90 % to the total NO_x. Other oxides of nitrogen, such as dinitrogen-trioxide (N_2O_3), dinitrogen-tetroxide (N_2O_4), and dinitrogen-pentoxide (N_2O_5), are formed in negligible amounts. Nitrous oxide (N_2O) is considered separrately.

9.3 NMVOC emissions

Due to the minor relevance of NMVOC emissions for power plants no split of species is given.

9.4 Heavy metal emissions

The heavy metals, which are of most environmental concern, are: arsenic (As), cadmium (Cd), chromium (Cr), copper (Cu), mercury (Hg), nickel (Ni), lead (Pb), selenium (Se) and zinc (Zn). This selection has been laid down by the UN-ECE Task Force on Heavy Metals, the PARCOM/ATMOS programme (cf. /35/) and the HELCOM programme. In the case of heavy oil combustion, vanadium emissions (V) are also of importance. In fly ash particles most of these elements occur as oxides or chlorides. The contribution of various forms of mercury to the emissions from combustion source categories in Europe is given in the following Figure 2:



[1] Hg° elemental form
Hg^{II} oxidised form
Hg^{P} particle-bound

Figure 2: Contribution of various forms of mercury to the emissions from combustion source categories in Europe in 1987 (in % of total) /29/

10 UNCERTAINTY ESTIMATES

Uncertainties of emission data result from the use of inappropriate or inaccurate emission factors, and from missing or inappropriate statistical information concerning activity data. Uncertainty estimates discussed here are related to the use of emission factors with different background information. At this stage a quantification of the uncertainty related to the use of emission factors is not feasible, due to the limited availability of data. However, the precision of emission estimates can be improved by applying individually determined emission factors.

The aim of the following procedure is to show the Guidebook-user how a lack of information concerning the fuel and technical characteristics of a combustion facility gives rise to a high uncertainty in the allocation of the appropriate emission factor. The whole span of possible emission factors is defined by the specification of the type of fuel used, the type of boiler, and the type of primary and secondary measures. The more information about these topics can be gathered, the smaller the span of possible emission factors becomes.

The following diagram (Figure 3) gives as an example the range of NO_x emission factors [g/GJ] for pulverised coal combustion depending on the level of specification.

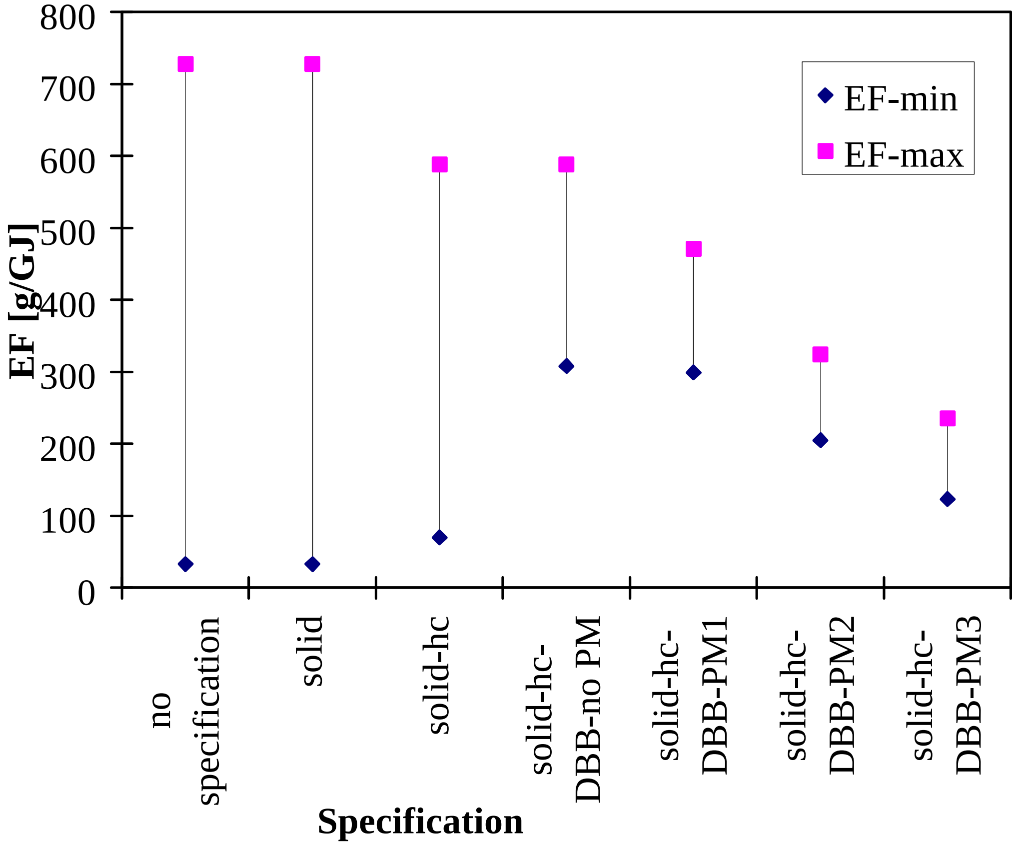


Figure 3: Ranges of NO_x emission factors for the combustion of pulverised coal

The level of specification is defined as follows:

- „no information“	- the whole range of combustion sources is taken into account,
- „solid“	- only solid fuels are taken into account,
- „solid-hc“	- only hard coal is considered,
- „solid-hc-DBB-no PM“	- hard coal and combustion technique are taken into account (here dry bottom boiler (DBB), without primary measures),
- „solid-hc-DBB-PM1“	- hard coal, DBB and primary measures are taken into account with a reduction efficiency of 0.2 ,
- „solid-hc-DBB-PM2“	- hard coal, DBB and primary measures are taken into account with a reduction efficiency of 0.45 ,
- „solid-hc-DBB-PM3“	- hard coal, DBB and primary measures are taken into account with a reduction efficiency of 0.6 .

In Figure 3 a large difference between minimum and maximum emission factors indicates high uncertainties in the allocation of appropriate emission factors. A specification of emission factors only concerning the type of fuel used (e.g. hard coal) is not sufficient. The range of NO_x emission factors for the combustion of pulverised coal is significantly reduced if technique related specifications are considered.

11 WEAKEST ASPECTS / PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

The weakest aspects discussed here are related to the determination of emission factors. Methodological shortcomings are discussed in this section for the main pollutants SO_2, NO_X and heavy metals.

11.1 SO_2 emissions

The approach for the determination of SO_2 emission factors is based on a simple mass balance calculation as the formation mechanisms of sulphur dioxide within the boiler depend almost entirely on the sulphur input. Therefore, for the formation of sulphur dioxide, fuel characteristics are of main influence. The accuracy of this approach is determined by the following fuel parameters: lower heating value, fuel sulphur content and sulphur retention in ash (see Equation (5)). The sulphur content and the lower heating value can be highly variable between different fuel categories and can furthermore vary to a large extent within one fuel category. Therefore, default values for sulphur content and lower heating value should be avoided. However, if emission factors for SO_2 have to be calculated, representative values for the sulphur content and the lower heating value should be based on measured data from individual fuel analysis.

The sulphur retention in ash α_S depends mainly on the content of alkaline components of the fuel. This is only relevant for coal (e.g. CaO, MgO, Na_2O, K_2O) and for the case of additive injection. For a more precise determination of α_S, the Ca/S ratio (amount of calcium/sulphur content of fuel)[8], the particulate diameter, the surface character of CaO, the temperature (optimum ca. 800 °C), the pressure, the residence time, etc. should be taken into account. Therefore, the assessment of α_S should be based on an extended set of parameters.

Besides the fuel characteristics, the reduction efficiency and availability of secondary measures are of relevance for the determination of the SO_2 emission factors. Default values are proposed in Table 7, but measured data from individual combustion plants should preferably be used.

11.2 NO_X EMISSIONS

The approach for the calculation of NO_X emission factors is based on empirical relations. For fuel-NO only fuel characteristics are taken into account. The formation of thermal-NO increases exponentially with combustion temperatures above 1,300 °C (see /56/). At this stage,

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[8] Alternatively the Ca/S ratio is defined as the amount of additives related to the sulphur content of the flue gas, and is given for a brown coal fired dry bottom boiler as 2.5 - 5 as an example, for a stationary FBC as 2 - 4, for a circulating FBC < 2 etc. /55/.

no satisfactory result has been achieved to determine the thermal-NO formation by using kinetic equations. For inventory purposes, an empirical parameter γ has been introduced (see Annex 5), which represents the fraction of thermal-NO formed. At this stage default values of γ depending on the type of boiler are given. Further work should focus on a more precise determination of this factor.

Load dependence of the pollutant NO_x has been taken into account. For old installations a quantitative relation has been given as an example for German power plants. The validity of this relation should be verified for other countries.

Furthermore, the reduction efficiency of primary or secondary measures are of relevance for the determination of NO_x emission factors. Default values for reduction efficiencies and availabilities are proposed in Tables 10 and 11, but measured data from individual combustion plants should preferably be used.

11.3 Heavy metals

Heavy metals undergo complex transformations during the combustion process and downstream of the boiler, referring to e.g. fly ash formation mechanisms. The approaches for the determination of heavy metal emission factors are based on empirical relations, where fuel and technical characteristics are of main influence. The heavy metal contents can be highly variable between different fuel categories (e.g. coal and heavy fuel oil) and can furthermore vary to a large extent within one fuel category (up to 2 orders of magnitude). Therefore, default values for heavy metal contents in fuel should be avoided and measured values should be used as far as possible.

For inventory purposes, parameters, such as enrichment factors, fractions of fly ash leaving the combustion chamber, fraction of heavy metals emitted in gaseous form, have been introduced. Further work should be invested into a more precise determination of these parameters. In addition, it should be taken into account, that the reduction efficiency of (dust) abatement measures depends on the heavy metal. Heavy metal specific reduction efficiencies should be determined.

11.4 Other aspects

Emission factors for SO_2, NO_2 and CO, whether calculated or given in the tables, are related to full load conditions. In order to assess the relevance of start-up emissions, a detailed investigation has been accomplished by using measured values from different types of boiler (see also Annex 15). The qualitative and quantitative statements obtained in this approach should be verified.

The emission factors have been determined by considering the pollutants separately. Possible mutual interactions between the formation mechanisms of different pollutants (e.g. NO and N_2O) have been neglected and should be assessed in further work.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

This section is not relevant for combustion plants considered as point sources.

13 TEMPORAL DISAGGREGATION CRITERIA

The temporal disaggregation of annual emission data (top-down approach) provides a split into monthly, weekly, daily and hourly emission data. Temporal disaggregation of annual emissions released from combustion plants as point sources can be obtained from the temporal change of the production of electrical power or the temporal change of the consumption, taking into account a split into:

- summer and winter time,
- working days and holidays,
- standstill times,
- times of partial load behaviour and
- number of start-ups / type of load design.

This split should be carried out for defined categories of power plants which take into account the main relevant combinations of types of fuel used and types of boiler installed (similar split as used for the emission factor Tables in Section 8).

The disaggregation of annual emissions into monthly, daily or hourly emissions can be based on a step-by-step approach /76/ according to the following equations:

- Monthly emission:

$$E_{M_n} = \frac{E_A}{12} \cdot f_n \tag{25}$$

E_{M_n} Emission in month n; n = 1, ..., 12 [Mg]

E_A Annual emission [Mg]

f_n Factor for month n; n = 1, ..., 12 [ ]

- Daily emission:

$$E_{D_{n,k}} = \frac{E_{M_n}}{D_k} \cdot f_k \cdot \frac{1}{CF_n} \tag{26}$$

$E_{D_{n,k}}$ Emission of day k in month n; k = 1, ..., D_k; n = 1, ..., 12 [Mg]

E_{M_n} Emission in month n; n = 1, ..., 12 [Mg]

D_k Number of days in month n [ ]

f_k Factor for day k; k = 1, ..., D_k [ ]

CF_n Correction factor for month n [ ]

- Hourly emission:

$$E_{H_{n,k,l}} = \frac{E_{D_{n,k}}}{24} \cdot f_{n,l} \qquad (27)$$

$E_{H_{n,k,l}}$	Emission in hour l in day k and month n; l = 1, ..., 24; k = 1, ..., D_k ; n = 1, ..., 12 [Mg]
$E_{D_{n,k}}$	Emission of day k in month n; k = 1, ..., D_k ; n = 1, ..., 12 [Mg]
$f_{n,l}$	Factor for hour l in month n; l = 1, ..., 24; n = 1, ..., 12 [ ]
D_k	Number of days in month n [ ]

The factors (relative activities) for month f_n, day f_k and hour $f_{n,l}$ can be related e.g. to the total fuel consumption or the net electricity production in public power plants. Figure 4 gives an example of a split for monthly factors based on the fuel consumption e.g. for Public Power Plants:

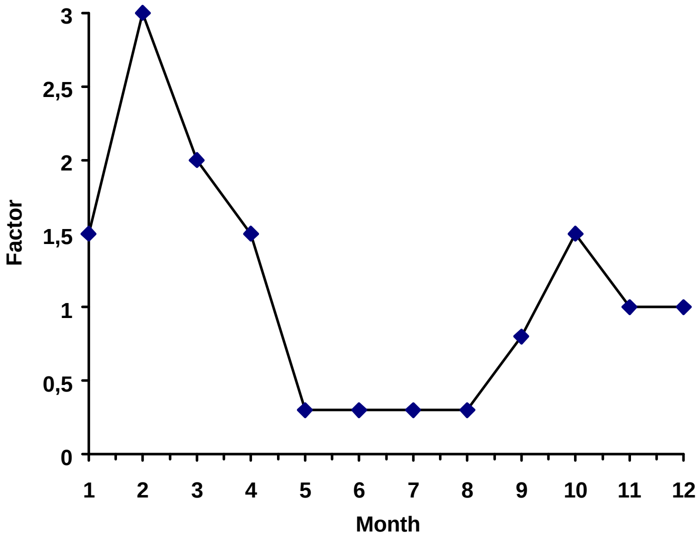
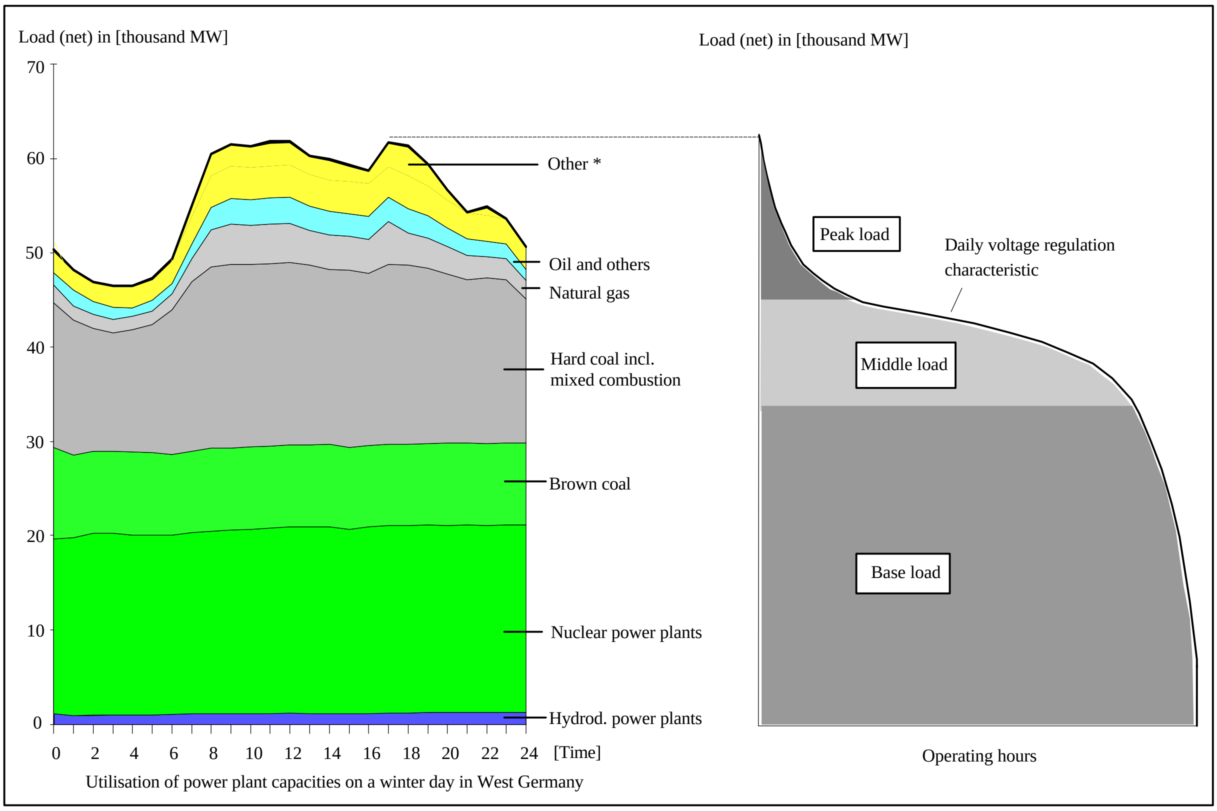


Figure 4: Example of monthly factors for total fuel consumption in Public Power Plants

A split concerning the load design, which determines the annual number of start-ups can be given as follows (see also Table 11):

- Base load: The boiler/plant is normally in continuous operation during the year; start-ups occur relatively seldom (ca. 15 times per year) depending on maintenance periods which occur mostly in summer. The fuel mostly used in base load boilers is brown coal.
- Middle load: The boiler/plant is in operation in order to meet the energy demand on working days (Monday until Friday); start-ups can occur up to 150 times per year. The fuel mostly used in middle load boilers is hard coal.
- Peak load: The boiler/plant is in operation in order to meet the short term energy demand; start-ups can occur up to 200 times per year. The fuels mostly used in peak load boilers are gas or oil.

The allocation of power plants to the different load designs is given as an example in Figure 5.



*Other includes: Storage pump power plants, power supply from industry etc.

Figure 5: Load variation and arrangement of power plants according to the voltage regulation characteristic (cf. /117/, /118/).

It can be assumed that all power plants of a country with the same allocation of fuel, boiler and load have the same temporal behaviour.

14 ADDITIONAL COMMENTS

15 SUPPLEMENTARY DOCUMENTS

15.1 Computer programme

A computer programme for the calculation of SO_2 and NO_2 emission factors for pulverised coal combustion has been designed, and is available on floppy disc. It has been designed under MICROSOFT EXCEL 4.0 (English version). Default values for the required input data are proposed to the user; a detailed users manual is given in Annex 14. For example, NO_X concentrations in [mg/m³] were calculated with the computer programme and presented together with the emission factors in [g/GJ] as listed in Annexes 10 and 11. An integral part of the computer programme is the calculation of the flue gas volume as given in Annex 6.

15.2 LIST OF ANNEXES

Annex 1: Example of different possible considerations of boilers as a common plant

Annex 2: Determination of SO_2 emission factors (flow sheet)

Annex 3: Determination of SO_2 emission factors (description)

Annex 4: Determination of NO_X emission factors (flow sheet)

Annex 5: Determination of NO_X emission factors (description)

Annex 6: Determination of the specific flue gas volume (flow sheet and description)

Annex 7: Composition and lower heating value (H_u) of hard coal in coal mining countries

Annex 8: Composition and lower heating value (H_u) of brown coal in coal mining countries

Annex 9: Conditions for exemplary calculation of NO_X emission factors

Annex 10: Emission factors and flue gas concentrations for NO_X obtained by model calculations (see Annexes 4 and 5) for hard coal (see Annex 7)

Annex 11: Emission factors and flue gas concentrations for NO_X obtained by model calculations (see Annexes 4 and 5) for brown coal (see Annex 8)

Annex 12: Comparison between measured and calculated SO_2 and NO_X emission data

Annex 13. Sensitivity analysis of the computer programme results

Annex 14: Users’ manual for the emission factor calculation programme (for version September, 1995)

Annex 15: Determination of start-up emissions and start-up emission factors.

Annex 16: List of abbreviations

16 VERIFICATION PROCEDURES

As outlined in the chapter “Concepts for Emission Inventory Verification“, different general verification procedures can be recommended. The aim of this section is to develop specific verification procedures for emission data from combustion plants as point sources. The verification procedures considered here are principally based on verification on a national and on a plant level. Moreover, it can be distinguished between the verification of activity data, of emission factors and of emission data.

16.1 Verification on a national level

For combustion plants as point sources, emissions and activities have to be verified. The total emissions from point sources are added together to obtain national total emissions (bottom-up approach). These national total emissions should be compared to emission data derived independently (top-down approach). Independent emission estimates can be obtained by using average emission factors and corresponding statistical data like the total fuel input for all sources, total thermal capacity, total heat or power produced, or by using emission estimates from other sources (e.g. organisations like energy agencies).

The total fuel consumption should be reconciled with energy balances, which often have break-downs for large point sources (e.g. electricity, heat generation and industrial boilers). Furthermore, the total number of plants installed as well as their equipment should be checked with national statistics.

Emission density comparisons can be achieved through comparison of e.g. emissions per capita or emissions per GDP with those of countries with a comparable economic structure.

16.2 Verification on a plant level

It should firstly be verified that separate inventories have been compiled for boilers, stationary engines, and gas turbines (according to SNAP code). The verification at plant level relies on comparisons between calculated emission factors and those derived from emission measurements. An example for such a comparison is given in Annex 12.

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Institute for Industrial Production
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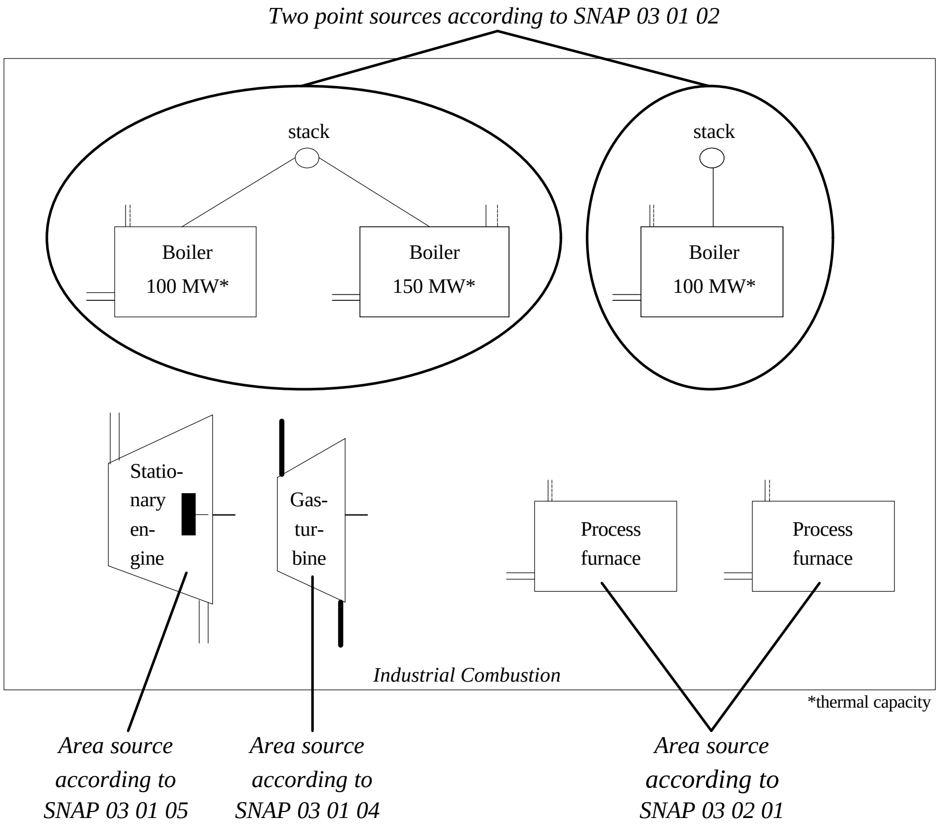
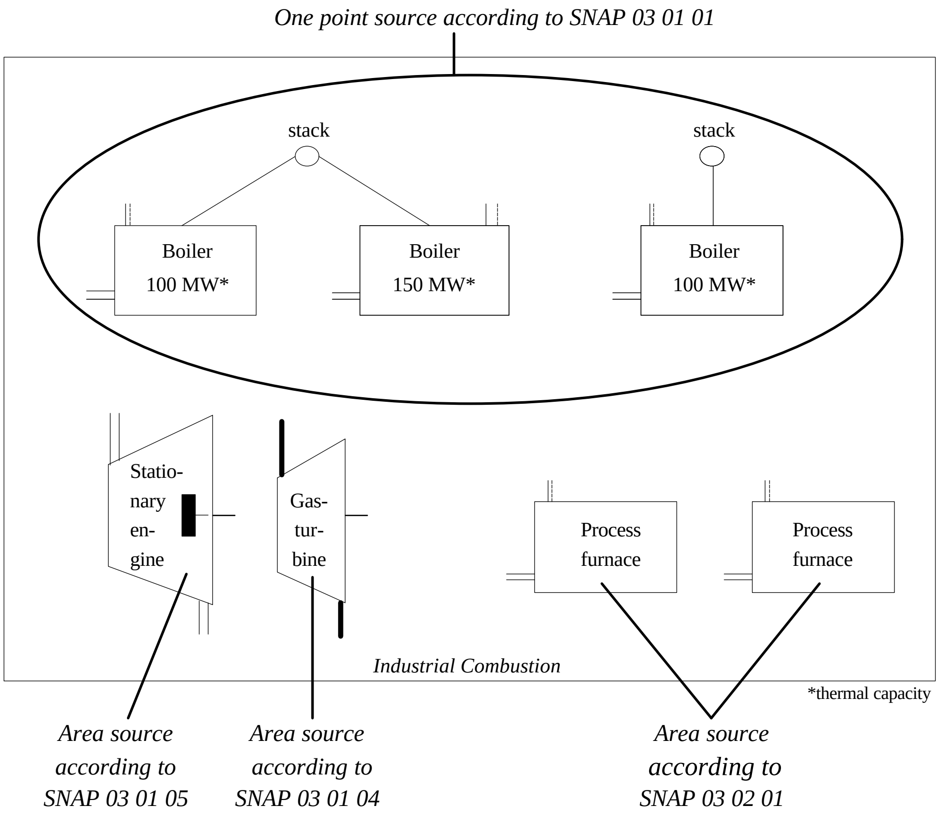
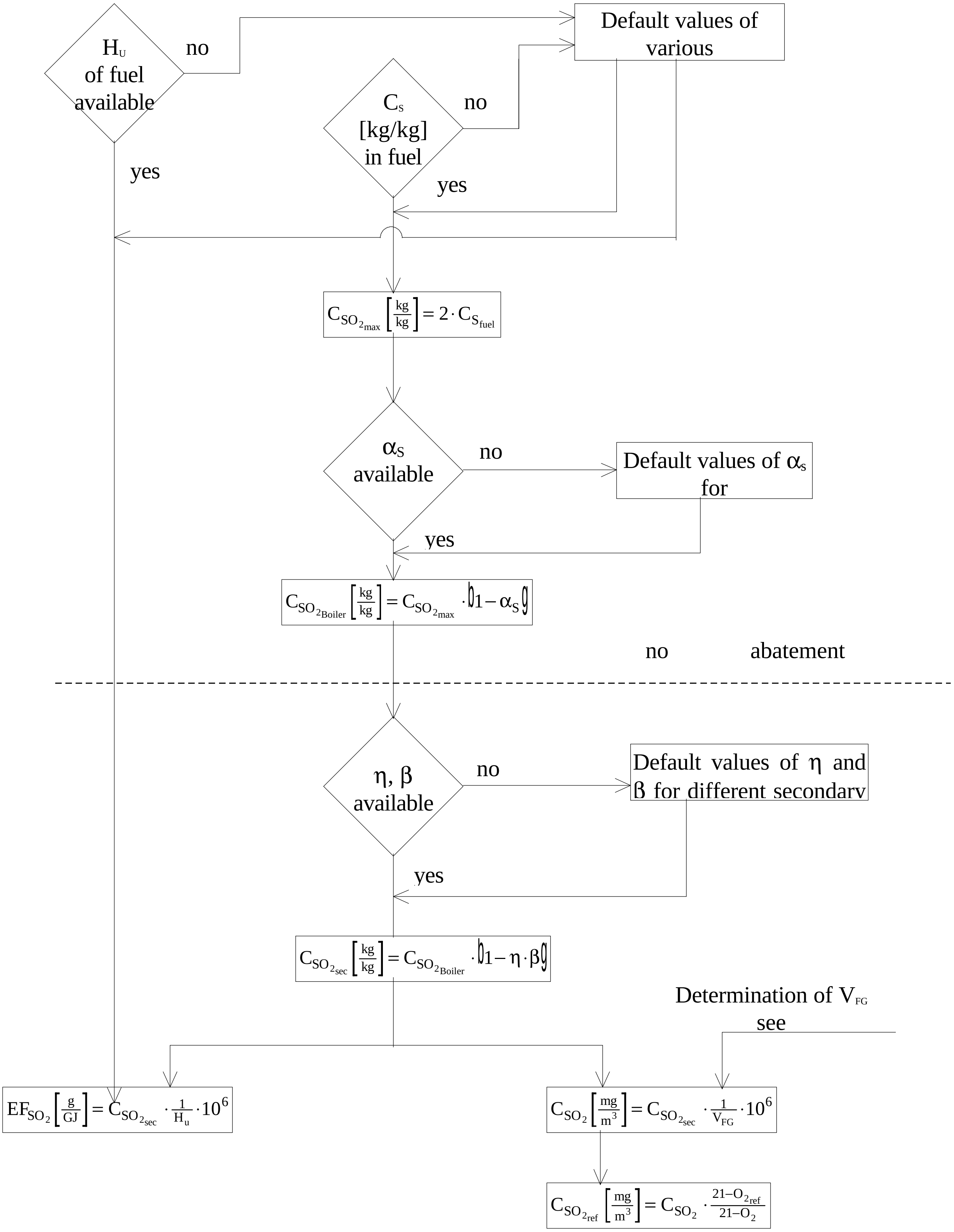
Annex 1: Example of different possible considerations for boilers as a common plant





Annex 2: Determination of SO_2 emission factors (flow sheet, for description see Annex 3)



Annex 3: Determination of SO_2 emission factors (description)

The calculation procedure is performed in three steps:

I The fuel sulphur reacts stoichiometrically with oxygen O_2 to sulphur dioxide SO_2. Default values for the sulphur content $C_{S_{fuel}}$ in hard and brown coal are given in Annexes 7 and 8. The result is the maximum attainable amount of sulphur dioxide $C_{SO_{2.max}}$ given by:

$$C_{SO_{2max}} = 2 \cdot C_{S_{fuel}} \tag{3-1}$$

$C_{S_{fuel}}$ sulphur content of fuel (in mass element/mass fuel [kg/kg])

$C_{SO_{2.max}}$ maximum attainable amount of sulphur dioxide (in mass pollutant/mass fuel [kg/kg])

II The maximum attainable amount of sulphur dioxide $C_{SO_{2.max}}$ is corrected by the sulphur retention in ash α_s. As a result, the real boiler emission of sulphur dioxide $C_{SO_{2,boiler}}$ fuel is obtained:

$$C_{SO_{2boiler}} = C_{SO_{2max}} \cdot (1 - \alpha_s) \tag{3-2}$$

$C_{SO_{2.boiler}}$ real boiler emission of sulphur dioxide (in mass pollutant/mass fuel [kg/kg])

$C_{SO_{2.max}}$ maximum attainable amount of sulphur dioxide (in mass pollutant/mass fuel [kg/kg])

α_S sulphur retention in ash [ ]

The sulphur retention in ash depends e.g. on fuel characteristics and temperature inside the boiler. If there is no data for α_S available, default values for various fuels are given in Table 8.

III The boiler emission of sulphur dioxide is corrected by the reduction efficiency η and availability β (for definition of β see Section 3.2) of the secondary measure installed, according to:

$$C_{SO_{2sec}} = C_{SO_{2boiler}} \cdot (1 - \eta \cdot \beta) \tag{3-3}$$

$C_{SO_{2.sec}}$ sulphur dioxide downstream secondary measure (in mass pollutant/mass fuel [kg/kg])

$C_{SO_{2.boiler}}$ real boiler emission of sulphur dioxide (in mass pollutant/mass fuel [kg/kg])

η reduction efficiency of secondary measure [ ]

β availability of secondary measure [ ]

The result is called secondary sulphur dioxide $C_{SO_{2.sec}}$. If there is no data for η and β available, default values for various flue gas desulphurisation techniques (FGD) are given in Table 7.

The obtained $C_{SO_{2.sec}}$ value is converted to C_{SO_2} in flue gas and to the emission factor EF_{SO_2} according to the following Equations:

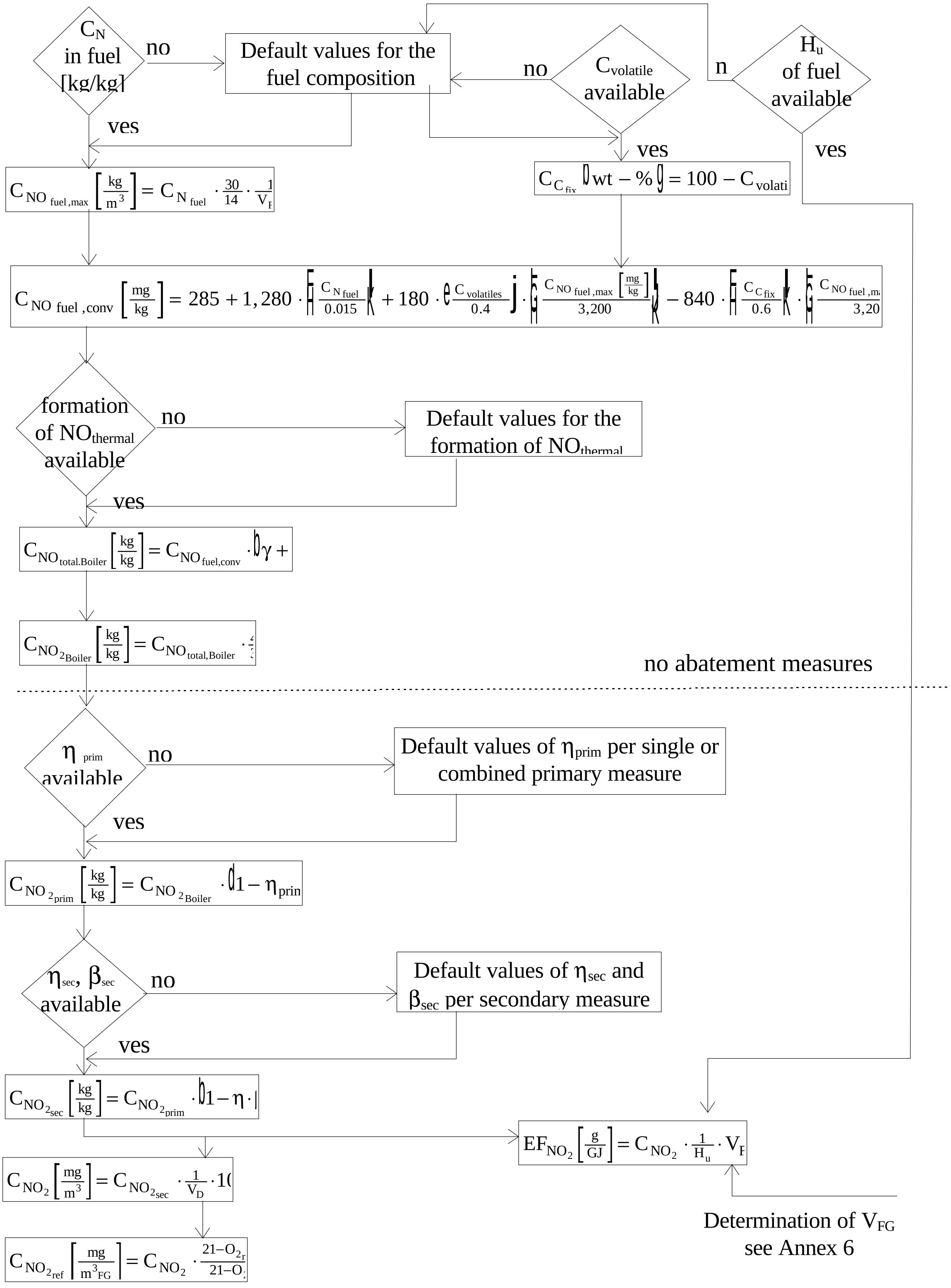
$$C_{SO_2} = C_{SO_{2.sec}} \cdot \frac{1}{V_{FG}} \cdot 10^6 \qquad (3\text{-}4)$$

$$EF_{SO_2} = C_{SO_{2.sec}} \cdot \frac{1}{H_u} \cdot 10^6 \qquad (3\text{-}5)$$

C_{SO_2}	sulphur dioxide in flue gas (in mass pollutant/volume flue gas [mg/m^3])
$C_{SO_{2.sec}}$	sulphur dioxide downstream of secondary measure (in mass pollutant/mass fuel [kg/kg])
V_{FG}	dry flue gas volume volume (in volume flue gas/mass fuel [m^3/kg])
EF_{SO_2}	emission factor for sulphur dioxide [g/GJ]
H_u	lower heating value [MJ/kg]

The dry flue gas volume V_{FG} can be determined according to Annex 6. Emission data in [mg/m^3] are useful to compare measured and calculated values. The same equations are used for the unit conversion of $C_{SO_{2.boiler}}$. Default values for the lower heating values of hard and brown coal are given in Annexes 7 and 8.

Annex 4: Determination of NO_x emission factors (flow sheet, for description see Annex 5)



Annex 5: Determination of NO_X emission factors (description)

The determination of NO_x emission factors takes into account the formation of fuel-NO and thermal-NO. The formation of fuel-NO is based on fuel parameters. But the total amount of fuel-nitrogen cannot be completely converted into fuel-NO (as obtained in Equation (5-1)). Therefore, the realistic formation of fuel-NO is described by an empirical relation (see Equation (5-2)). The formation of thermal-NO is expressed by an an additional fraction which depends on the type of boiler.

The calculation procedure of the NO_X emission factor is performed in three steps: In the first step the maximum NO emission resulting from stoichiometric conversion of fuel nitrogen is calculated. The NO emission obtained is further corrected by taking into account the formation of thermal-NO. NO is converted into NO_2 and primary and secondary measures are taken into account in steps two and three.

I The fuel-nitrogen reacts in a stoichiometric manner with oxygen O_2 to form nitrogen oxide. The default values for the nitrogen content $C_{N_{2fuel}}$ in hard and brown coal are given in Annexes 7 and 8. The maximum attainable amount of fuel nitrogen oxide $C_{NO_{fuel.max}}$ is obtained:

$$C_{NO_{fuelmax}} = C_{N_{fuel}} \cdot \frac{30}{14} \cdot \frac{1}{V_{FG}} \tag{5-1}$$

$C_{NO_{fuel.max}}$	maximum attainable amount of fuel nitrogen oxide (in mass pollutant/volume flue gas [kg/m^3])
$C_{N_{fuel}}$	nitrogen content in fuel (in mass nitrogen/mass fuel [kg/kg])
V_{FG}	specific flue gas volume (in volume flue gas/mass fuel [m^3/kg])[9]

The fuel-nitrogen content $C_{N_{fuel}}$ is not completely converted into $C_{NO_{fuel}}$. The converted part of fuel-nitrogen to fuel-NO $C_{NO_{fuel.conv}}$ can be determined by the following empirical formula /50, 51/ related to zero percent of oxygen in dry flue gas:

$$C_{NO_{fuelconv}} = 285 + 1{,}280\left(\frac{C_{N_{fuel}}}{0.015}\right) + 180\left(\frac{C_{volatiles}}{0.4}\right)\left(\frac{C_{NO_{fuelmax}}}{3{,}200}\right) - 840\left(\frac{C_{C_{fix}}}{0.6}\right)\left(\frac{C_{NO_{fuelmax}}}{3{,}200}\right) \tag{5-2}$$

$C_{NO_{fuel.conv}}$	fuel-NO released (in mass pollutant/mass flue gas [mg/kg])[2]
$C_{N_{fuel}}$	nitrogen content in fuel (in mass nitrogen/mass fuel [kg/kg]), maf
$C_{volatiles}$	fuel content of volatiles (in mass volatiles/mass fuel [kg/kg]), maf
$C_{NO_{fuel.max}}$	maximum attainable amount of fuel nitrogen oxide (in mass pollutant/mass flue gas [mg/kg])[10]
$C_{C_{fix}}$	fixed carbon in fuel (in mass carbon/ mass fuel [kg/kg]), maf

---

[9] The programme calculates stoichiometrically the specific flue gas volume based on the complete fuel composition.

[10] Note: $C_{NO.fuel.max}$ and $C_{NO.fuel.conv}$ are given in the unit (mass pollutant/mass flue gas [mg/kg]). For the conversion between (mass pollutant/mass flue gas [mg/kg]) and (mass pollutant/volume flue gas [kg/m3]) the flue gas density (in mass flue gas/volume flue gas [kg/m^3]) has to be taken into account, which is calculated stoichiometrically from the fuel composition within the computer programme.

The fixed carbon in the fuel is determined according to the equation $C_{C_{fix}} = 1 - C_{volatiles}$. Equation (5-2) is valid for nitrogen oxide emissions from premixed flames; the coefficient of correlation is $r^2 = 0.9$ for 20 coals and $r^2 = 0.75$ for 46 coals /51/. The data has been obtained by field and pilot-scale measurements. Basically tests are conducted in a 70,000 Btu/hr (20.5 kW) refractory lined furnace with variable heat extraction. Coal was injected through special configurations. A nozzle produces an uniform heterogeneous mixture of coal and air prior to combustion and represents the limit of intensely mixed flames produced with high swirl. Further tests have been established in large scale furnaces. The results from all measurements combined with additional information based on literature data have been used to establish a correlation which predicts the relative dependence of nitrogen oxide emissions on fuel properties. /51/ Further calculations with Equation (5-2) based on measured data have been provided in /50/. The comparison between measured and calculated values has shown that the results from Equation (5-2) are very good for high volatile coals and are satisfactory for medium volatile coals /50/.

Assuming that the formation of fuel-NO is much more important than the formation of thermal-NO (fuel-NO amounts to 70 - 90 %), the content of thermal-NO formed can be expressed as a fraction γ (where γ depends on the type of boiler) of NO_{fuel}. The total content of nitrogen oxide formed in the boiler $C_{NO_{total.boiler}}$ is given by:

$$C_{NO_{total_{boiler}}} = C_{NO_{fuel_{conv}}} + C_{NO_{thermal}} = C_{NO_{fuel_{conv}}} \cdot \left(1 + \gamma\right) \tag{5-3}$$

$C_{NO_{total.boiler}}$	total content of nitrogen oxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])
$C_{NO_{fuel.conv}}$	fuel-NO released (in mass pollutant/mass flue gas [kg/kg])
$C_{NO_{thermal}}$	content of thermal-NO formed (in mass pollutant/mass flue gas [kg/kg])
γ	fraction for thermal-NO formed [ ]

The following default values for γ can be recommended: DBB $\gamma = 0.05$, WBB $\gamma = 0.3$. Furthermore, the amount of thermal-NO can be influenced by load (see also Section 11.2).

The total boiler emissions of nitrogen dioxide $C_{NO_{2.boiler}}$ can be calculated as follows:

$$C_{NO_{2_{boiler}}} = C_{NO_{total_{boiler}}} \cdot \frac{46}{30} \tag{5-4}$$

$C_{NO_{2_{boiler}}}$	total content of nitrogen dioxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])
$C_{NO_{total_{boiler}}}$	total content of nitrogen oxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])

II The total boiler content of nitrogen dioxide given by $C_{NO_{2.boiler}}$ is reduced by taking into account primary measures with the reduction efficiency η_{prim}. The result is the content of primary nitrogen dioxide $C_{NO_{2.prim}}$:

$$C_{NO_{2prim}} = C_{NO_{2boiler}} \cdot \left(1 - \eta_{prim}\right) \qquad (5\text{-}5)$$

$C_{NO_{2.prim}}$	content of primary nitrogen dioxide (in mass pollutant/mass flue gas [kg/kg])
$C_{NO_{2boiler}}$	total content of nitrogen dioxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])
η_{prim}	reduction efficiency of primary measure(s) [ ]

As there is only incomplete data available for reduction efficiencies, default values are given for the individual and relevant combinations of primary measures for different types of boilers and fuels (see Table 8). In the case of combined primary measures with known individual reduction efficiencies $\eta_{prim,1}$, $\eta_{prim,2}$, etc., the following equation can be used:

$$C_{NO_{2prim}} = C_{NO_{2boiler}} \cdot \left(1 - \eta_{prim1}\right) \cdot \left(1 - \eta_{prim2}\right) \cdot \left(1 - \eta_{prim3}\right) \qquad (5\text{-}6)$$

$C_{NO_{2.prim}}$	content of nitrogen dioxide taking into account primary measures (in mass pollutant/mass flue gas [kg/kg])
$C_{NO_{2boiler}}$	total content of nitrogen dioxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])
η_{prim_k}	individual reduction efficiency of primary measure k [ ]

It should be taken into account, that the reduction efficiencies of primary measures are not independent of each other.

III The emission of primary nitrogen dioxide $C_{NO_{2.prim}}$ is corrected by the reduction efficiency η_{sec} [ ] and the availability β_{sec} [ ] (for definition of β see Section 3.2) of the secondary measure installed, according to:

$$C_{NO_{2sec}} = C_{NO_{2.prim}} \cdot \left(1 - \eta_{sec} \cdot \beta_{sec}\right) \qquad (5\text{-}7)$$

$C_{NO_{2.sec}}$	nitrogen dioxide downstream of secondary measure (in mass pollutant/mass flue gas [kg/kg])
$C_{NO_{2.prim}}$	content of nitrogen dioxide taking into account primary measures (in mass pollutant/mass flue gas [kg/kg])
η_{sec}	reduction efficiency of secondary measure [ ]
β_{sec}	availability of secondary measure [ ]

If there is no data for η_{sec} and β_{sec} available, default values for various DeNOx techniques are given in Table 9.

The obtained value of $C_{NO_{2.sec}}$ is converted into C_{NO_2} and into the emission factor EF_{NO_2} according to the following equations:

$$C_{NO_2} = C_{NO_{2sec}} \cdot \frac{1}{V_D} \cdot 10^6 \tag{5-8}$$

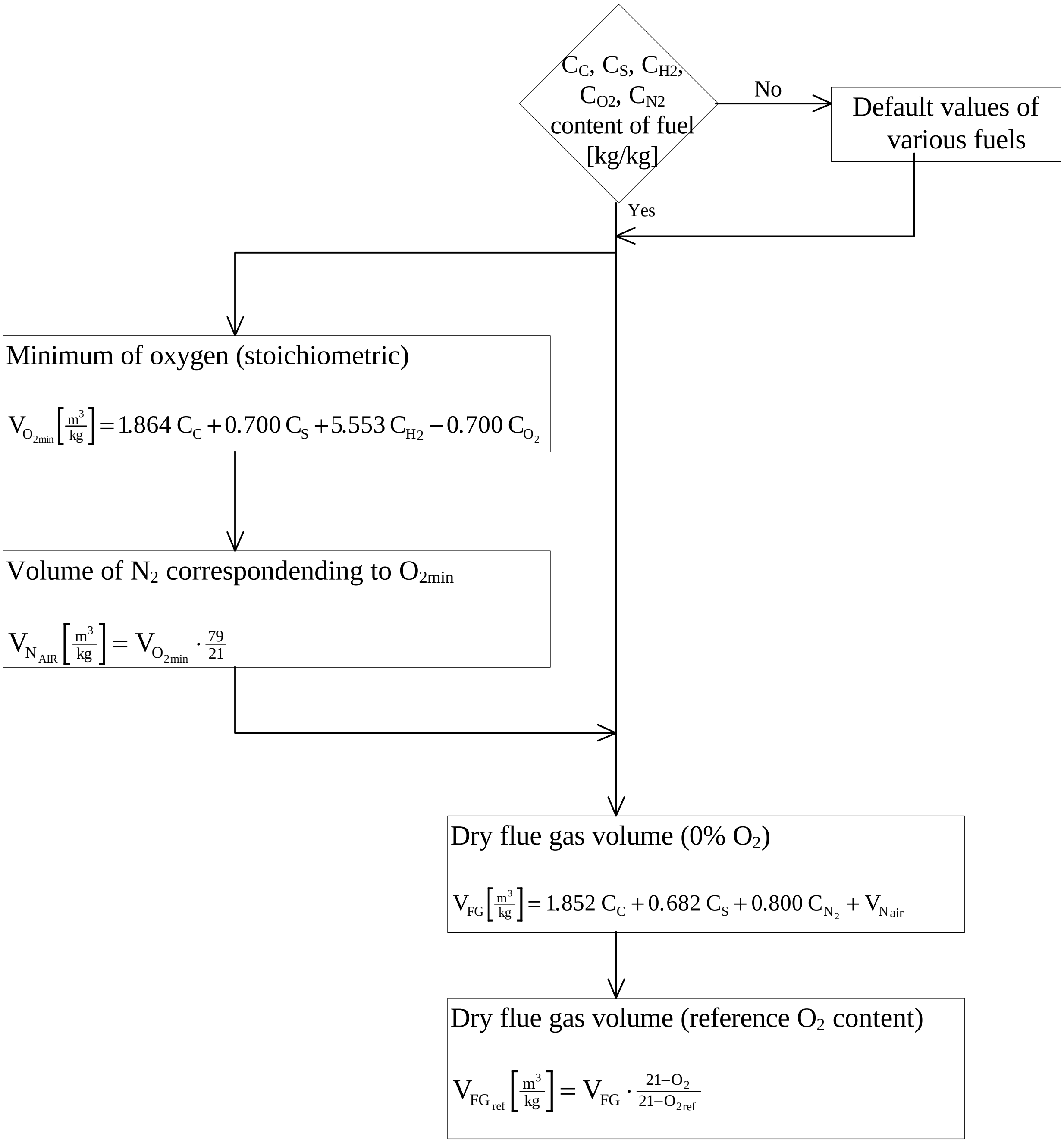
$$EF_{NO_2} = C_{NO_2} \cdot \frac{1}{H_u} \cdot V_{FG} \tag{5-9}$$

C_{NO_2}	nitrogen dioxide in flue gas (in mass pollutant/volume flue gas [mg/m^3])
$C_{NO_{2sec}}$	nitrogen dioxide downstream of secondary measure (in mass pollutant/mass flue gas [kg/kg])
V_D	dry flue gas volume (in volume flue gas/mass flue gas [m^3/kg])
V_{FG}	specific dry flue gas volume (in volume flue gas/mass fuel [m^3/kg])
EF_{NO_2}	emission factor for nitrogen dioxide [g/GJ]
H_u	lower heating value [MJ/kg]

The specific dry flue gas volume V_{FG} can be determined according to Annex 6. Emission data expressed in [mg/m^3] are used for comparing measured and calculated values. Default values for lower heating values for hard and brown coal are given in Annexes 7 and 8.

Annex 6: Determination of the specific flue gas volume (flow sheet and description)

The specific flue gas volume has to be determined in order to convert the emission factors, which have been obtained in [g/GJ], into [mg/m^3], which allows a comparison to measured data. The approach is given in the following flow sheet:



For the determination of the flue gas volume, the elemental analysis of the fuel (content of carbon C_C, sulphur C_S, hydrogen C_H, oxygen C_{O_2} and nitrogen C_N (maf)) has to be known. If no data of the elemental analysis is available, default values of hard and brown coals are proposed in Annexes 7 and 8. The volume of oxygen required for a stoichiometric reaction $V_{O_{2min}}$ can be determined as follows:

$$V_{O_{2min}} = 1.864 \cdot C_C + 0.700 \cdot C_S + 5.553 \cdot C_H - 0.700 \cdot C_{O_2} \qquad (6\text{-}1)$$

$V_{O_{2min}}$	volume of oxygen required for stoichiometric reaction (in volume oxygen/mass fuel [m^3/kg])
C_C	content of carbon in fuel (in mass carbon/mass fuel [kg/kg])
C_S	content of sulphur in fuel (in mass sulphur/mass fuel [kg/kg])
C_H	content of hydrogen in fuel (in mass hydrogen/mass fuel [kg/kg])
C_{O_2}	content of oxygen in fuel (in mass oxygen/mass fuel [kg/kg])

The constants in Equation (6-1) represent stoichiometric factors for the volume of oxygen required for the combustion of 1 kg carbon, sulphur or hydrogen in [m^3/kg]. The corresponding volume of nitrogen in the air $V_{N_{air}}$ is given by Equation (6-2):

$$V_{N_{air}} = V_{O_{2min}} \cdot \frac{79}{21} \qquad (6\text{-}2)$$

$V_{N_{air}}$	volume of nitrogen in the air (in volume nitrogen/mass fuel [m^3/kg])
$V_{O_{2min}}$	volume of oxygen required for stoichiometric reaction (in volume oxygen/mass fuel [m^3/kg])

The specific dry flue gas volume at 0 % oxygen V_{FG} can be determined by using Equation (6-3):

$$V_{FG} = 1.852 \cdot C_C + 0.682 \cdot C_S + 0.800 \cdot C_N + V_{N_{air}} \qquad (6\text{-}3)$$

V_{FG}	specific dry flue gas volume (in volume flue gas/mass fuel [m^3/kg])
C_C	content of carbon in fuel (in mass carbon/mass fuel [kg/kg])
C_S	content of sulphur in fuel (in mass sulphur/mass fuel [kg/kg])
C_N	content of nitrogen in fuel (in mass nitrogen/mass fuel [kg/kg])
$V_{N_{air}}$	volume of nitrogen in the air (in volume nitrogen/mass fuel [m^3/kg])

The constants in Equation (6-3) represent stoichiometric factors for the volume of oxygen required for the combustion of 1 kg carbon, sulphur or nitrogen in [m^3/kg]. The obtained values of V_{FG} at 0 % oxygen are converted to the reference content of oxygen in flue gas according to Equation (6-4):

$$V_{FG_{ref}} = V_{FG} \cdot \frac{21 - O_2}{21 - O_{2ref}} \qquad (6\text{-}4)$$

$V_{FG_{ref}}$	volume of specific flue gas under reference conditions (in volume flue gas/mass fuel [m^3/kg])
V_{FG}	volume of specific flue gas obtained (in volume flue gas/mass fuel [m^3/kg])
O_2	content of oxygen in the flue gas obtained [%]
O_{2ref}	content of oxygen in the flue gas under reference conditions [%]

Annex 7: Composition and lower heating value (H_u) of hard coal in coal mining countries

	elemental analysis (maf) [wt.-%]										volatiles (maf) [wt.-%]		H_u (maf) [MJ/kg]	
country	C		N		O		H		S					
	value	standard deviation	value	standard deviation	value	standard deviation	value	standard deviation	value	standard deviation	value	standard deviation	value	standard deviation
Australia1)	84.6	2.26	1.8	0.15	7.8	2.08	5.2	0.29	0.6	0.21	34.0	5.94	33.70	1,03
Canada1)	86.6	1.8	1.4	0.15	6.1	1.5	5.1	0.56	0.9	0.43	33.9	6.34	33.04	2.32
China1)	81.9	1.95	1.1	0.32	11.4	2.4	4.9	0.21	1.05	0.35	36.3	2.32	32.06	0,80
Columbia1)	78.5	6.37	1.5	0.13	12.4	4.3	5.2	0.62	0.9	0.19	42.2	2.70	31.83	1.93
Czech Rep.2)	85.98	2.23	1.5	0.17	6.27	2.30	5.09	0.70	1.16	0.68	30.88	8.92	34.00	2.44
France2)	87.91	1.76	1.29	0.24	5.60	1.58	4.50	0.47	0.70	0.17	22.81	5.82	34.86	1.56
Germany RAG1)6)	90.2	1.77	1.6	0	3	1.41	4.4	0.56	0.9	-	15.8	9.60	35.23	0.29
Ger. others2)	87.00	2.44	1.49	0.27	5.75	1.94	4.76	0.68	1.02	0.32	25.52	6.58	30.10	1.75
CIS1)	77.5	0	0.7	0	16.1	0	5.4	0	0.3	0	39.0	3.20	31.85	1.66
Hungary2)	84.10	1.51	1.42	0.69	5.79	0.54	5.09	0.11	3.62	0.55	24.4	3.98	34.16	1.05
India1)	76.5	3.22	1.3	0.25	16.2	4	5.6	0.4	0.4	0.32	47.9	2.44	29.48	2.25
Poland4)	80.0		1.0		7.0		5.0		1.0		38.5		(21.00)5)	
Portugal3)	87.0		0.95		5.4		4.9		0.94		32.1		(27.58)5)	
South Africa1)	80.3	5.78	2.1	0.73	8.8	1.2	4.9	1.19	0.9	0.24	31.9	2.37	32.36	0.73
UK1)	84.5	0.6	1.8	0	n. a.		5.4	0.06	n. a.		38.2	1.84	33.80	0.58
USA1)	84.3	2	1.6	0.17	7.5	1.65	5.5	0.38	1.1	0.58	38.1	4.31	33.89	0.88
Venezuela1)	84.2	1.7	1.5	0.07	7.6	2.19	6	0.49	0.7	0	43.2	3.98	34.00	1.00

1) Association of German Coal Importers 1992 /72

2) Brandt 1981 /47/

n.a.- no data are available

3) Madeira: Personal communication, EDP-Electricielade Portugal, Lisboa, May 1994

4) Debsky: Personal communication, Energy Information Centre, Warsaw, May 1994

5) lower heating value as received (ar)

6) RAG= Ruhr coal

Annex 8: Composition and lower heating value (H_u) of brown coal in coal mining countries

	elemental analysis (maf) [wt.-%]										volatiles (maf)		H_u (maf)	
country	C		N		O		H		S		[wt.-%]		[MJ/kg]	
	value		value		value		value		value		value		value	
Czech Rep. 2)	70.09	3.32 4)	1.07	0.22 4)	21.74	3.42 4)	5.64	0.64 4)	1.48	0.82 4)	56.67	4.62 4)	28.2	2.39 4)
Germany														
-Rheinisch coal 1)	68	62-72 5)	1.0	0.7-1.3 5)	25.2	22-30 5)	5	4.5-5.5 5)	0.8	0.2-1.1 5)	38 6)	-	27.3	19.4-31.7 5)
-Middle Ger. 1)	72		0.8		18.3		5.5		3.4		57.5		28.8	
-East Ger. 1)	69.5		1.0		23.1		5.8		0.6		58.7		25.7	
Hungary 1) - 1	63.8		(1.1)		26.8		4.8		3.5		61.8		35.7	28.8-42.6 5)
Hungary 2) - 2	69.82	2.62 4)	1.06	0.45 4)	18.91	2.23 4)	5.54	0.12 4)	4.49	2.46 4)	39.30	1.04 4)	28.4	1.20 4)
Poland 7)	69.5	66-73 5)	1.1	0.7-1.5 5)	19	13-25 5)	6	5-7 5)	1		50		25	23 - 26 5)
Portugal 2)	67.44	1.01 4)	0.91	0.18 4)	22.61	2.89 4)	4.4	0.74 4)	4.62	2.43 4)	54.64	8.84 4)	24.8	2.6 4)
Turkey 1) - 1	61.4		0.8		29.6		5.1		5.1		n. a.		21.2	19.8-22.7 5)
Turkey 3) - 2	62.6	7.84 4)	2.0	0.67 4)	24.0	4.48 4)	4.9	0.56 4)	6.2	4.77 4)	56.0	3.93 4)	26.6	

1) IEA coal research - brown coal

2) Brandt

3) Kücükbayrak, S.; Kadioglu, E.: Desulphurisation of some Turkish lignites by pyrolysis, FUEL, Vol. 67, 6/1988

4) standard deviation

5) range

6) value recommended by RAG

7) Debsky: Personal communication, Energy Information Centre, Warsaw, May 1994

n. a. - no data available

Annex 9: Conditions for exemplary calculation of NO_x emission factors

Annex 9 presents the values which have been chosen for the calculation of NO_x emission factors (according to Section 4.2.1). The results of the calculations are given in the following Annexes 10 (for hard coal) and 11 (for brown coal). Both annexes contain emission factors in [g/GJ] as well as concentrations in [mg/m^3] which have been determined under the conditions given in Table 9-1:

Table 9-1: Selected input parameters for model calculations determining NO_X emission factors as given in Annexes 10 and 11

Type of coal[1]	Type of boiler	Fraction of thermal NO NO_{th} [ ]	Reduction efficiency of primary measures η_{prim}[2] [ ]	Reduction efficiency of secondary measures η_{sec} [ ]	Availability β_{sec} [ ]
hc	DBB	0,05	LNB 0,20 LNB/SAS 0,45 LNB/OFA 0,45 LNB/SAS/OFA 0,60	SCR 0,8	0,99
	WBB	0,30	LNB 0,20 LNB/SAS 0,45 LNB/OFA 0,40 LNB/SAS/OFA 0,60	SCR 0,8	0,99
bc	DBB	0,05	LNB 0,20 LNB/SAS 0,45 LNB/OFA 0,40 LNB/SAS/OFA 0,60	-	-

[1] Elementary analyses of hard and brown coal are given in Annexes 7 and 8.

[2] The reduction efficiency is given as an example for selected primary measures (see Section 4.2).

Abbreviations: hc = hard coal, bc = brown coal

For individual calculations of NO_X emission factors, the computer programme (users' manual see Section 15 and Annex 14) can be used.

Annex 10: Emission factors and flue gas concentrations for NO_X obtained by model calculations (see Annexes 4 and 5) for hard coal (Annex 7)

Hard coal from	Type of boiler	Uncontrolled		Primary control[2)]			Secondary control[3)]	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1)]	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
Australia	DBB	568	1620	LNB	454	1300	95	270
				LNB/SAS	312	893	65	186
				LNB/OFA	312	893	65	186
				LNB/SAS/OFA	227	649	47	135
	WBB	703	2140	LNB	562	1720	117	357
				LNB/SAS	387	1180	80	245
				LNB/OFA	422	1290	88	268
				LNB/SAS/OFA	281	858	59	178
Canada	DBB	506	1390	LNB	405	1110	84	230
				LNB/SAS	278	762	58	158
				LNB/OFA	278	762	58	158
				LNB/SAS/OFA	202	554	42	115
	WBB	627	1830	LNB	501	1460	10	304
				LNB/SAS	345	1010	72	209
				LNB/OFA	376	1100	78	228
				LNB/SAS/OFA	251	732	52	152
China	DBB	413	1180	LNB	331	943	69	196
				LNB/SAS	227	648	47	135
				LNB/OFA	227	648	47	135
				LNB/SAS/OFA	165	472	34	98
	WBB	512	1560	LNB	409	1250	85	259
				LNB/SAS	281	856	59	178
				LNB/OFA	307	934	64	194
				LNB/SAS/OFA	205	623	43	130
Columbia	DBB	535	1570	LNB	428	1250	89	261
				LNB/SAS	294	861	61	179
				LNB/OFA	294	861	61	179
				LNB/SAS/OFA	214	626	45	130

for footnotes see bottom of this table

Annex 10 continued, for footnotes see bottom of this table

Hard coal from	Type of boiler	Uncontrolled		Primary control[2)]			Secondary control[3)]	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1)]	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
Columbia	WBB	662	2070	LNB	529	1650	110	344
				LNB/SAS	364	1140	76	237
				LNB/OFA	397	1240	83	258
				LNB/SAS/OFA	265	827	51	172
Czech Republic	DBB	483	1370	LNB	387	1100	80	228
				LNB/SAS	266	753	55	157
				LNB/OFA	266	753	55	157
				LNB/SAS/OFA	193	548	40	114
	WBB	598	1810	LNB	479	1450	100	301
				LNB/SAS	329	995	68	207
				LNB/OFA	359	1080	75	226
				LNB/SAS/OFA	239	723	50	150
France	DBB	374	1080	LNB	299	863	62	180
				LNB/SAS	205	594	43	123
				LNB/OFA	205	594	43	123
				LNB/SAS/OFA	149	432	31	90
	WBB	463	1430	LNB	370	1140	77	237
				LNB/SAS	254	784	53	163
				LNB/OFA	278	855	58	178
				LNB/SAS/OFA	185	570	39	119
Germany RAG	DBB	384	1090	LNB	307	872	64	181
				LNB/SAS	211	600	44	125
				LNB/OFA	211	600	44	125
				LNB/SAS/OFA	154	436	32	90
	WBB	476	1440	LNB	381	1150	779	240
				LNB/SAS	262	792	54	165
				LNB/OFA	285	864	59	180
				LNB/SAS/OFA	190	576	40	120

Annex 10 continued, for footnotes see bottom of this table

Hard coal from	Type of boiler	Uncontrolled		Primary control[2)]			Secondary control[3)]	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1)]	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
Germany others	DBB	495	1240	LNB	396	990	82	206
				LNB/SAS	272	681	57	142
				LNB/OFA	272	681	57	142
				LNB/SAS/OFA	198	495	41	103
	WBB	613	1630	LNB	490	1310	102	272
				LNB/SAS	337	899	70	187
				LNB/OFA	368	980	76	204
				LNB/SAS/OFA	245	654	51	136
Hungary	DBB	401	1150	LNB	320	920	67	191
				LNB/SAS	220	633	46	132
				LNB/OFA	220	633	46	132
				LNB/SAS/OFA	160	460	33	96
	WBB	496	1520	LNB	397	1220	82	253
				LNB/SAS	273	835	57	174
				LNB/OFA	298	911	62	190
				LNB/SAS/OFA	198	608	41	126
CIS	DBB	308	923	LNB	247	739	51	154
				LNB/SAS	169	508	35	106
				LNB/OFA	169	508	35	106
				LNB/SAS/OFA	123	369	26	77
	WBB	382	1220	LNB	305	975	64	203
				LNB/SAS	210	671	44	139
				LNB/OFA	229	732	48	152
				LNB/SAS/OFA	153	488	32	101
India	DBB	551	1540	LNB	441	1230	92	256
				LNB/SAS	303	845	63	176
				LNB/OFA	303	845	63	176
				LNB/SAS/OFA	220	615	46	128

Annex 10 continued, for footnotes see bottom of this table

Hard coal from	Type of boiler	Uncontrolled		Primary control[2]			Secondary control[3]	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1]	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
India	WBB	682	2030	LNB	545	1620	113	338
				LNB/SAS	375	1120	78	232
				LNB/OFA	409	1120	85	253
				LNB/SAS/OFA	273	812	57	169
South Africa	DBB	569	1650	LNB	456	1320	95	275
				LNB/SAS	313	910	65	189
				LNB/OFA	313	910	65	189
				LNB/SAS/OFA	228	662	47	138
	WBB	705	2180	LNB	564	1750	117	364
				LNB/SAS	388	1200	81	250
				LNB/OFA	423	1310	88	273
				LNB/SAS/OFA	282	874	59	182
USA	DBB	563	1610	LNB	450	1290	94	268
				LNB/SAS	310	885	64	184
				LNB/OFA	310	885	64	184
				LNB/SAS/OFA	225	644	47	134
	WBB	697	2120	LNB	558	1700	116	353
				LNB/SAS	383	1170	78	243
				LNB/OFA	418	1270	87	265
				LNB/SAS/OFA	279	850	58	177
Venezuela	DBB	588	1670	LNB	471	1340	98	278
				LNB/SAS	324	919	67	191
				LNB/OFA	324	919	67	191
				LNB/SAS/OFA	235	668	49	139

Annex 10 continued

Hard coal from	Type of boiler	Uncontrolled		Primary control[2)]			Secondary control[3)]	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1)]	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
Venezuela	WBB	728	2210	LNB	583	1760	121	367
				LNB/SAS	401	1210	83	252
				LNB/OFA	437	1320	91	275
				LNB/SAS/OFA	291	882	61	184

[1)] PM = primary measures

[2)] primary measures as mostly used, see Table 8

[3)] taking into account secondary measures mostly used: SCR: reduction efficiency = 0.8, availability = 0.99

Annex 11: Emission factors and flue gas concentrations for NO_X obtained by model calculations (see Annexes 4 and 5) for brown coal (see Annex 8)

Brown coal from	Type of boiler	Uncontrolled		Primary control		
		EF $\left[\frac{g}{GJ}\right]$	Conc. $\left[\frac{mg}{m^3}\right]$	PM[1]	EF $\left[\frac{g}{GJ}\right]$	Conc. $\left[\frac{mg}{m^3}\right]$
Czech Republic	DBB	506	1.480	LNB	405	1190
				LNB/SAS	278	816
				LNB/OFA	304	890
				LNB/SAS/OFA	202	593
Germany						
- Rheinisch coal	DBB	325	985	LNB	260	788
				LNB/SAS	179	542
				LNB/OFA	195	591
				LNB/SAS/OFA	130	394
- Middle Germany	DBB	504	1.250	LNB	403	996
				LNB/SAS	277	685
				LNB/OFA	302	747
				LNB/SAS/OFA	202	498
- East Germany	DBB	539	1.460	LNB	431	1.160
				LNB/SAS	296	801
				LNB/OFA	323	873
				LNB/SAS/OFA	215	582
Hungary - 1	DBB	379	1.590	LNB	303	1.270
				LNB/SAS	208	874
				LNB/OFA	227	953
				LNB/SAS/OFA	151	635
Hungary - 2	DBB	379	1.100	LNB	304	879
				LNB/SAS	209	604
				LNB/OFA	228	659
				LNB/SAS/OFA	152	439
Portugal	DBB	461	1.260	LNB	369	1.010
				LNB/SAS	254	696
				LNB/OFA	277	759
				LNB/SAS/OFA	185	506
Turkey - 2	DBB	725	2.240	LNB	580	1.790
				LNB/SAS	399	1.230
				LNB/OFA	435	1.340
				LNB/SAS/OFA	290	895

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[1] PM = primary measures as given in Table 8

Annex 12: Comparison between measured and calculated SO_2 and NO_x emission data

The proposed methodology for the determination of SO_2 and NO_x emission factors is described in the Sections 4.1 and 4.2. Calculated flue gas concentrations in [mg/m^3] have been used for the derivation of emission factors in [g/GJ]. A comparison of measured concentrations in combustion plants in [mg/m^3] with calculated concentrations in [mg/m^3] can be used for verification purposes.

A comparison of measured concentrations with calculated flue gas concentrations downstream of the boiler is given as an example for some power plants in Table 12-1.

Table 12-1: Comparison of measured and calculated flue gas concentrations in raw gas of the boiler (taking into account primary reduction measures)[13)]

Type of boiler	Power plant	C_{SO_2} [mg/m^3]		C_{NO_2} [mg/m^3]	
		measured	calculated	measured	calculated
DBB	Altbach (FRG)[1)]	ca. 1,700	1,380 - 1,610	ca. 600	599 - 681
	Münster (FRG)[2)]	1,644 - 1,891	1,380 - 1,440	800 - 900	1,090
	Karlsruhe (FRG)[3)]	1,600 - 2,000	1,310 - 1,650	900 - 1,000	923 - 1,140
	Hanover (FRG)[4)]	1,600 - 1,800	1,610	ca. 800	681
	Mehrum (FRG)[5)]	ca. 2,700	1,610	ca. 800	990
	Nuremberg (FRG)[6)]	ca. 1,800	1,610	n. d.	1,240
	Heilbronn (FRG)[7)]	ca. 1,800	1,900 - 2,200	≤ 800	1,050 - 1,070
	IMATRAN (SF)[8)]	n. d.	1,480 - 1,700	ca. 225	516 - 747
	EPON (NL)[9)]	1,429 - 1,577	1,580 - 2,190	363 - 609	999 - 1,010
WBB	Aschaffenburg (FRG) [10)]	2,400	1,530	1,000	1,010
	Charlottenburg (FRG) [11)]	1,800	1,530	1,300	1,080
	Karlsruhe (FRG) [12)]	1,295 - 1,716	1,610	ca. 960	1,460

[1)] coal: Germany RAG, Germany others; reduction measures: WS; LNB/SAS, SCR; thermal capacity 1,090 MW

[2)] coal: Germany others, $\alpha_S = 0.15$; reduction measure: DESONOX ($\eta_{SO2} = 0.94$, $\eta_{NO2} = 0.82$); thermal capacity 100 MW

[3)] coal: individual data, $\alpha_S = 0.4$; reduction measures: WS ($\eta = 0.85$); LNB/opt. ($\eta = 0.3$); SCR; thermal capacity 1,125 MW

[4)] coal: Germany others; reduction measures: SDA; LNB/OFA, SCR; thermal capacity 359 MW

[5)] coal: Germany others; reduction measures: WS; LNB, SCR; thermal capacity 1,600 MW

[6)] coal: Germany others; reduction measures: SDA; SCR; thermal capacity 110 MW

[7)] coal: individual data; reduction measures: WS ($\eta = 0.95$); OFA, SCR; thermal capacity 1,860 MW

[8] coal: individual data; reduction measures: WS; LNB/OFA; electrical capacity 650 MW

[9] coal: individual data; reduction measures: FGD (η = 0.93); high temperature NO_x reduction (η = 0.4), electrical capacity 630 MW

[10] coal: Germany RAG; reduction measures: WS; SAS, SCR; thermal capacity 395 MW

[11] coal: Germany RAG; reduction measures: WS; OFA; thermal capacity 120 MW

[12] coal: individual data; reduction measures: WS (η = 0.88); SCR (η = 0.9; thermal capacity) 191 MW

[13] values refer to full load conditions

n. d. = no data available

Table 12-2: Comparison of measured and calculated flue gas concentrations downstream of secondary reduction measure (if installed)[13]

Type of boiler	Power plant	C_{SO_2} [mg/m^3]		C_{NO_2} [mg/m^3]	
		measured	calculated	measured	calculated
DBB	Altbach (FRG)[1]	ca. 250	150 - 176	ca. 200	125 - 142
	Münster (FRG)[2]	85 - 181	820 - 859	163 - 176	74
	Karlsruhe (FRG)[3]	240 - 300	208 - 261	190	192 - 238
	Hanover (FRG)[4]	200	176	150	142
	Mehrum (FRG)[5]	400	176	190	206
	Nuremberg (FRG)[6]	50 - 140	176	70 - 100	257
	Heilbronn (FRG)[7]	100 - 200	207 - 240	≤ 200	218 - 223
	IMATRAN (SF)[8]	n. d.	161 - 186	ca. 225	516 - 747
	EPON (NL)[9]	ca. 148	113 - 184	ca. 609	999 - 1,010
WBB	Aschaffenburg (FRG) [10]	70	167	200	209
	Charlottenburg (FRG) [11]	175	167	163	1,080
	Karlsruhe (FRG) [12]	47 - 165	207	ca. 150	159

[1] - [13] for footnotes see Table 12-1 above

n.d. = no data available

The quality and quantity of data obtained by the power plant operators vary greatly. For unknown compositions of coal and other missing parameters default values have been used (e.g. for coal compositions see Annexes 7 and 8).

The values in Table 12-1 are compared in the Figure 12-1 below:

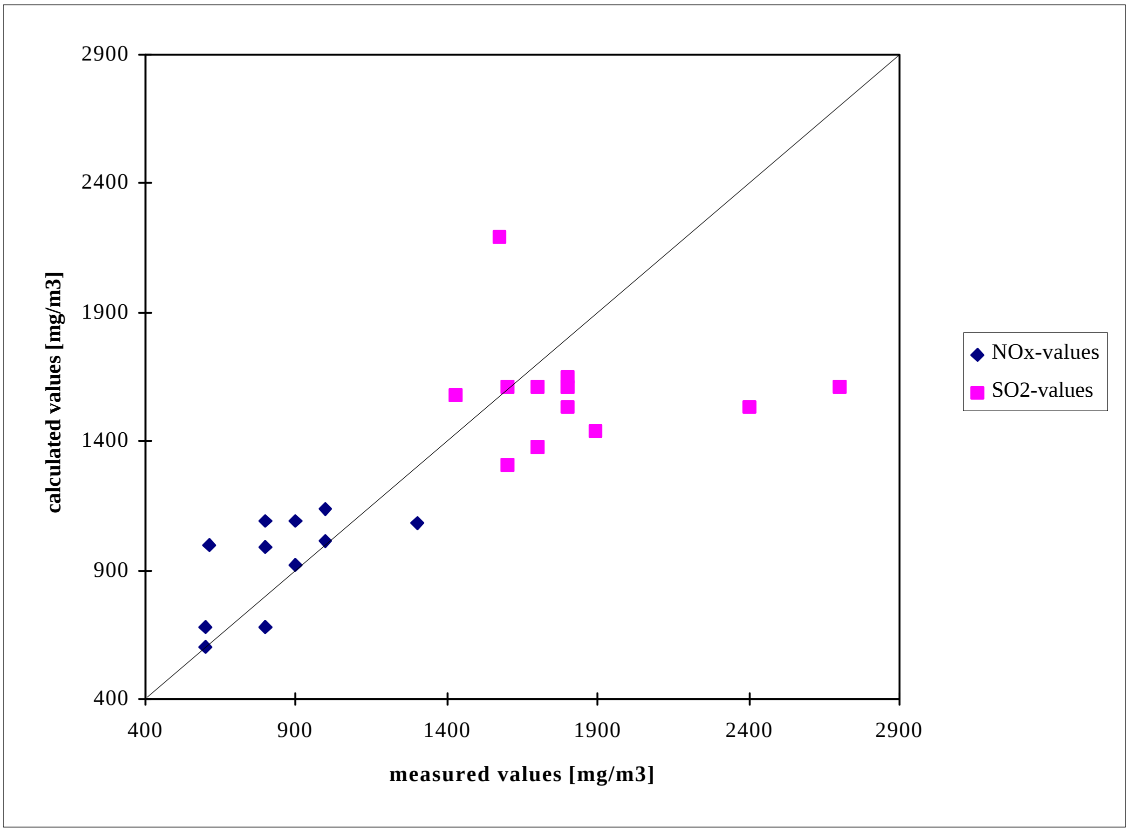


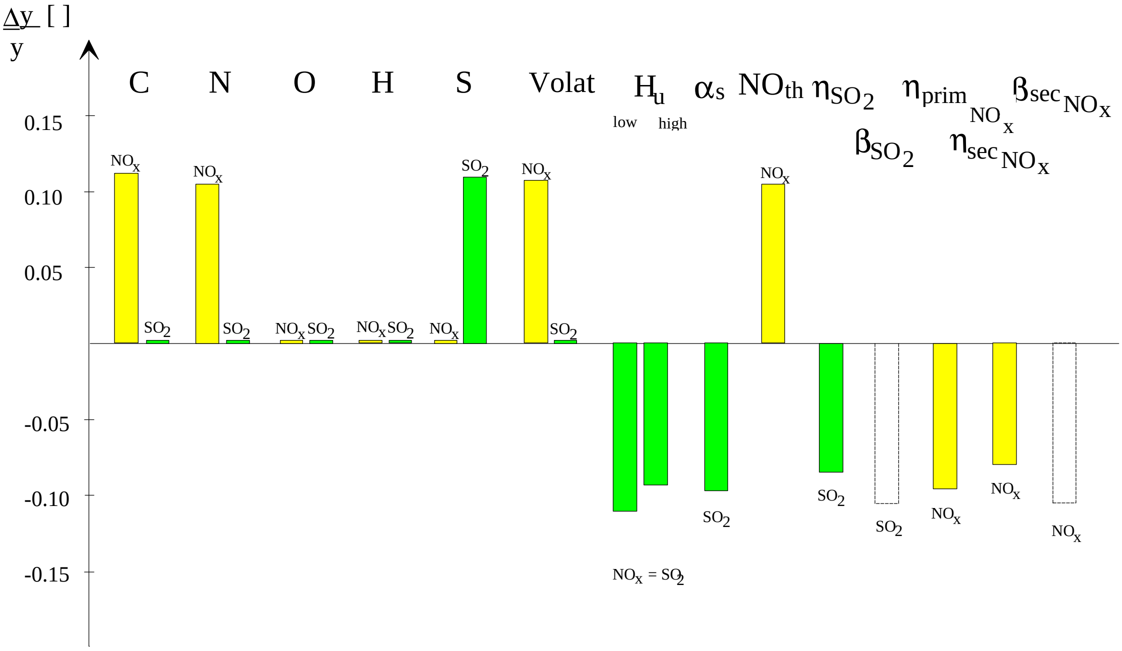
Figure 12-1: Comparison of measured flue gas concentrations [mg/m^3] and calculated flue gas concentrations [mg/m^3] downstream of the boiler

The comparison of measured flue gas concentrations and calculated flue gas concentrations shows that most values are scattered close to the middle axis.

Good correlations between measured and calculated values have been obtained for calculations which are only based on plant specific data provided by power plant operators. But for most calculations a mixture of plant specific data and default values for missing parameters has been used which leads to deviations from the middle axis. In particular strong differences occur for SO_2 emissions which show a tendency to be overestimated. The tendency can be explained by assumptions with regard to default values; e.g. the sulphur retention in ash varies greatly depending on the data availability.

Annex 13: Sensitivity analysis of the computer programme results

A sensitivity analysis was carried out with all model input parameters used. The 14 input parameters (fuel content of carbon C, nitrogen N, oxygen O, hydrogen H, sulphur S, volatiles Volat, lower heating value H_u, sulphur retention in ash α_S, fraction of thermal nitrogen oxide NO_{th}, reduction efficiency η and availability β of abatement measures) was arranged with respect to their influence on SO_2 and NO_x emissions. Each input parameter was varied by ±10 % except β_{SO2} and $\beta_{sec.NOx}$ which were varied only by - 4 % (dashed line); the variation of the calculated emission factors is presented in Figure 13-1.



Δy/y relative change of emission factors (pollutant as indicated)

Figure 13-1: Sensitivity analysis of the emission factor calculation programme results for pulverised coal combustion

For emission factors of SO_2 the sulphur content of fuel and the sulphur retention in ash are highly relevant. For emission factors of NO_x the fuel content of nitrogen, carbon and volatiles as well as the reduction efficiency of primary measures are highly relevant. The fuel contents of oxygen and hydrogen are not relevant. The relative change of emission factors concerning the lower heating value can be described for SO_2 and NO_x as an exponential curve: that means that uncertainties at lower levels of the heating values (e.g. for brown coal) influence the result stronger. The efficiency of secondary measures is of slightly less influence than the efficiency of primary measures. The availability of secondary measures is marked with a dashed line in Figure 13-1; a 4 % variation of this parameter has shown significant influence.

Annex 14: Users’ manual for the emission factor calculation programme (for September 1995 version)

Determination of SO_2 and NO_x emission factors for large combustion plants

1 Computer specifications

This programme requires MICROSOFT WINDOWS 3.1, a 3½" floppy disc drive, and at least 200 Kbyte on the hard disc. The programme has been designed in MICROSOFT EXCEL 4.0 - English Version.

2 Installation

The floppy disc received contains 19 files. All these files have to be installed on the hard disc. The following users’ guide is stored under README.DOC (written with MICROSOFT WORD FOR WINDOWS 2.1).

The software has to be installed on your hard disk "C" by using the following procedure:

- Create a new sub-directory with the name 'POWER_PL' by following the instructions:
  - in DOS go to C:\
  - type: MD POWER_PL
  - hit the <ENTER>-key
  - change into this sub-directory by typing: CD POWER_PL
  - hit the <ENTER>-key.
- To copy all the files from your floppy disc into the sub-directory 'POWER_PL' proceed as follows:
  - insert your disk into slot A (or B) of your PC
  - type COPY A: (or B:)*.*
  - hit the <ENTER>-key.

The installation of the programme is then complete.

3 How to work with the programme

3.1 Start the programme

- Start MICROSOFT WINDOWS 3.1 and MICROSOFT EXCEL 4.0 - English Version (or MICROSOFT EXCEL 5.0 - English Version).
- In 'FILE' - 'OPEN', go to hard disk 'C' and activate the sub-directory 'POWER_PL'. Then you will see all the necessary files in the programme in the left window.
- Choose the file 'POWER_PL.XLW' and hit the <ENTER>-key.
- Then the programme opens all the tables and macros needed.

3.2 Further proceedings with the programme

- When you see the first screen please type 'Ctrl'-'a' (or 'Strg'-'a') to start the programme. By hitting these two keys you start a macro, which takes you through all the levels of the programme. The input data for the programme are divided into background tables for the fuel used, for SO_2-specification and NO_X-specification.

  Fuel data input

  - First the programme asks for an identification of the model run. You are free to put in the name of the power plant, type of boiler, type of fuel (e. g. Heilbronn - dry bottom boiler - hard coal).
  - The next window requests the type of coal (hard coal or lignite).
  - The programme asks you to choose one of the fuel compositions listed. Select one of them by typing the corresponding number and hitting the 'OK'-key on the screen$^{1)}$. If the default values of the given fuel compositions do not correspond with your power plant, you have the possibility of putting in corrected values by choosing the last line of the table (line 17 or 10). Then the programme asks you to enter in the individual values. The values given by the 'question-window' can be kept by hitting the 'OK'-key on the screen.
  - Then the programme asks for the water content of the fuel and the reference-content of oxygen in the flue gas. The value given by the 'question-window' can be retained by hitting the 'OK'-key on the screen.

  SO_2 data specification

  - The programme asks you to choose one of the listed numbers as a value for the sulphur retention in ash. Please select one of them by typing the corresponding number and hitting the 'OK'-key on the screen1). If the default values for the sulphur retention in ash do not correspond with your power plant, you have the possibility of putting in corrected values by choosing the last line of the table (line 3). Then the programme asks you to put in the value.
  - The programme asks you to choose one of the listed secondary measures SO_2 . Please select one of them by typing the corresponding number and hitting the 'OK'-key on the screen$^{1)}$. If the default values of the efficiencies and availabilities of the secondary measures given do not correspond with those of your power plant, you have the possibility of putting put in corrected values by choosing the last line of the table (line 9). Then the programme asks you to put in the individual values.

    At this point the calculations for SO_2 are finished.

  NO_X data specification

  - The programme proceeds with the calculations of NO_2 by asking for a value for $NO_{thermal}$[1]. At this stage, the thermal NO (NOthermal) has to be put in as an exogenious value as given in the table. You have the possibility of putting in a new value by following the instructions on the screen.

- The next window requests the type of boiler (wet bottom boiler WBB- dry bottom boiler DBB).
- Then you have to choose a type of combination of primary measure installed. For some primary measures, reduction efficiencies are given as default values[11]. If you have better data available, you can put in new values choosing the last line of the table (line 17) and follow the instructions on the screen.
- Finally, you have to choose a type of combination of secondary measure installed[1]. As mentioned above, you can put in different values of efficiencies and availabilities by choosing one secondary measure from the table (typing the corresponding number). Or else you can put in your own values by selecting the last line of the table (line 6). Please follow the instructions on the screen.

At the end the following message appears on the screen: You can save the data-sheet named 'AINPUSO2.XLS' under a different name.

If you want to do further model runs, just type 'Ctrl'-'a' (or 'Strg'-'a') and the programme starts again.

In order to finish your calculation, just quit EXCEL without saving changes in any of the 19 basic files of this software.

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[11] If the tables with the default values are overlapped by a 'question-window' you can move this window: point on the headline of this little window with your mouse-pointer, hold your left mouse-button and move it.

Annex 15: Frame conditions of the detailed investigation concerning start-up emissions and start-up emission factors /based on 116/

Approach

Start-ups have to be considered in a boiler-by-boiler approach. In order to determine the relevance of start-up emissions compared to full load emissions, measured emission data for SO_2, NO_2 and CO obtained from power plant operators have been analysed. Start-up emissions and start-up emission factors have been determined in principle by using the detailed methodology described in Section 5.

Technical specifications

The analysis of start-up emissions was accomplished by using measured values from dry bottom boilers, wet bottom boilers and a gas fired boiler. The interpretation of start-up emissions and start-up emission factors should take into account specifications in the design of the boilers and in the configuration of secondary measures installed. In the following, particularities of the boilers considered are given:

- *Dry bottom boiler (thermal capacity 1,050 MW and 1,147 MW, hard coal fuelled)*

  The smaller boiler is equipped with a primary measure for NO_x reduction (SAS). The SCR is arranged in a high dust configuration (SCR-precipitator-FGD). This boiler is often started slowly and directly connected to the FGD.

  The larger boiler is also equipped with a primary measure for NO_x reduction (SAS). The SCR is also arranged in a high dust configuration (SCR-precipitator-FGD). Due to special arrangements (individual construction of two heat exchangers without any slip between raw and clean flue gas) when this boiler is started up the FGD is by-passed. This boiler is also called „quick“ start-up boiler.

- *Wet bottom boiler (thermal capacity 499 MW each, hard coal fuelled)*

  One boiler is equipped with primary measures for NO_x (like OFA and improved coal mills). The other boiler is not equipped with primary measures. Both boilers are equipped with a common FGD. The SCR is arranged in a tail-end-configuration (precipitator-FGD-SCR) and equipped with a natural gas fired additional furnace. The type of FGD is wet scrubbing (WS). Both boilers are started up directly connected to the FGD.

- *Natural gas fired boiler (thermal capacity 1,023 MW)*

  This boiler is rarely used. It is designed for quick start-ups. As a primary measure, special NO_x burners are installed. As a secondary measure an SCR is installed. SO_x abatement is not necessary due to the fact that low sulphur fuels are used.

Boilers without secondary measures show start-up emissions which are below the emissions under full load conditions. During start-ups boilers with secondary measures often show significantly higher SO_2 emissions than during the same time under full load conditions. Start-up emissions are released until the secondary measures are working under optimal conditions (for SO_2 and NO_2). CO emissions can be significant up to the time when the boiler operates at minimum load.

The relevance of start-up emissions depends on the following parameters which have to be considered when interpreting measured values (emissions or emission factors):

- the type of boiler (e.g. wet bottom boilers always release higher NO_x emissions than dry bottom boilers, due to higher combustion temperatures),

- the type of fuel used (e.g. SO_x emissions are directly related to the sulphur content of the fuel; fuel-nitrogen also contributes to the formation of NO_x),

- the status of the boiler at starting-time (hot, warm or cold start, see Table 11).
  - the specifications of any individual start-up, like
    - the duration and the velocity of the start-up,
    - load level obtained (reduced load or full load),
    - the configuration of secondary measures (e.g. the start-up time of the high-dust-configurations (SCR-precipitator-FGD) depends on the boiler load, due to the fact that the SCR catalyst is directly heated by the flue gas; tail-end-configurations (precipitator-FGD-SCR) can have shorter start-up times, due to the fact that the SCR catalyst can be preheated by an additional burner),
    - start-up of the flue gas desulphurisation directly or in by-pass configuration,
    - emission standards which have to be met (boiler-specific emission standards can be set up below the demands of the LCP Directive).

Annex 16: List of abbreviations

a	Content of ash in coal (wt.-%)
AC	Activated Carbon Process
ar	As received
bc	Brown coal
BFCB	Bubbling Fluidised Bed Combustion
CF_n	Correction factor for month n [ ]
CFBC	Circulating Fluidised Bed Combustion
CC	Combined Cycle
CI	Compression Ignition
$CM_{HM_{FA.raw}}$	Heavy metal concentration in raw gas fly ash [$\frac{g}{Mg}$]
$CM_{HM_{FA.clean}}$	Heavy metal concentration in fly ash in clean flue gas [$\frac{g}{Mg}$]
$\overline{C}$	Expected value (mean value) of the flue gas concentration [$\frac{mg}{m^3}$]
C_i	Concentration [$\frac{kg}{kg}$], [$\frac{g}{Mg}$], [$\frac{mg}{m^3}$], i = SO_2, S_{fuel} etc.
CODPOL	Code of pollutants according to CORINAIR
D_k	Number of days per month
DBB	Dry Bottom Boiler
DeNOx	Denitrification unit(s)
DESONOX	Type of simultaneous process for SO_2 and NO_x removal based on catalytic reaction
DSI	Dry Sorbent Injection
E	Emission within the period considered [Mg]
E^A	Emission during start-up period [Mg]
E^V	Emission for full load conditions during start-up period [Mg]
EF^A	Emission factor for start-up time [g/GJ]
$EF^{Reduced\ load}$	Emission factor for reduced load conditions [g/MWh]
EF^V	Emission factor under full load conditions [g/GJ]
EF_i	Emission factor, mostly in the unit [$\frac{g}{GJ}$], i = SO_2, NO_x, CO_2 etc.
EF_f	Fly ash emission factor of raw gas [kg/Mg]
ESP	Electrostatic precipitator
f_a	Fraction of ash leaving combustion chamber as particulate matter (wt.-%)
f_e	Enrichment factor [ ]
f_g	Fraction of heavy metal emitted in gaseous form (wt.-%)
f_k	Factor of day k

f_n	Factor for month
$f_{n,l}$	Factor for hour
F^E	Ratio for start-up and full load emissions [ ]
F^{EF}	Ratio for start-up and full load emission factors [ ]
FBC	Fluidised Bed Combustion
FGD	Flue Gas Desulphurisation
FGR	Flue Gas Recirculation
g	Gaseous state of aggregation
GF	Grate Firing
GHV	Gross Heating Value
GT	Gas Turbine
hc	Hard coal
HM	Heavy metal, trace elements
H_u	Lower heating value [$\frac{MJ}{kg}$]
k^{load}	Ratio of reduced load to full load emission factor [ ]
K_c	Mean efficiency of dust control equipment (%)
K_t	Share of plant capacity connected to dust control equipment (%)
l	Liquid state of aggregation
L	Actual load
LCP	Large Combustion Plant
LIFAC	Special type of DSI, mostly used in Finland
LNB	Low NOx Burner
$\dot{m}^L$	Fuel consumption during periods at reduced load conditions [GJ]
$\dot{m}^V$	Fuel consumption during full load periods [GJ]
$\dot{m}_{fuel}$	Fuel consumption per time unit [$\frac{kg}{a}$], [$\frac{kg}{h}$]
$\dot{m}_{FA}$	Average annually emitted fly ash $\left[\frac{Mg}{a}\right]$
$\dot{m}_q^A$	Fuel consumption during start-up period [GJ]; q= type of start-up (cold start, warm start, hot start)
maf	Moisture and ash free
NMVOC	Non-Methane Volatile Organic Compounds
No_{fuel}	Fuel based emission of nitrogen oxide
$NO_{thermal}$	Thermal nitric oxide
OFA	Overfire Air

P	Daily coal consumption $[\frac{\text{Mg}}{\text{d}}]$
PM	Primary Measure
RAG	Coal mined in Rhine area in Germany
s	Solid state of aggregation
SAS	Staged Air Supply
SC	Simple Cycle
SCR	Selective Catalytic Reduction
SI	Spark Ignition
SNAP	Selected Nomenclature of Air Pollutants
SNCR	Selective Non-Catalytic Reduction
SNOX	Technical specification of DESONOX-process
SPA	Spray Dryer Absorption
SPF	Split Primary Flow
ST	Stoker
Stat. E.	Stationary Engine
$\dot{V}$	Flue gas volume flow rate $[\frac{\text{m}^3}{\text{h}}]$
$\overline{\dot{V}}$	Average flow rate $[\frac{\text{m}^3}{\text{h}}]$
V_D	Dry flue gas volume per mass flue gas $[\frac{\text{m3}}{\text{kg}}]$
V_{FG}	Dry flue gas volume per mass fuel $[\frac{\text{m3}}{\text{kg}}]$
VOC	Volatile Organic Compounds
WAP	Walter Process
WBB	Wet Bottom Boiler
WL	Wellmann-Lord
WS	Wet Scrubbing
α_s	Sulphur retention in ash [ ]
β_{sec}	Availability of secondary abatement technique [ ]
γ	Fraction of thermal-NO formed [ ]
η_i	Reduction efficiency [ ], i = primary measure, secondary measure

SNAP CODES: **(See below)**

SOURCE ACTIVITY TITLE: **COMBUSTION PLANTS AS AREA SOURCES**

The following activities are taken into account when combustion plants are treated collectively as area sources. Boilers, furnaces (except process furnaces), gas turbines and stationary engines which may also be considered individually as point sources are covered by this chapter as well as by chapter B111 on ”Combustion Plants as Point Sources”.

SNAP94 Codes	**Combustion plants as area sources**								
	Boilers/furnaces							Gas turbines	Stationary engines
	Thermal capacity [MW]	Public power and cogeneration plants	District heating	Industrial combustion	Commercial and institutional combustion	Residential combustion	Agriculture forestry and fishing		
01 01 02	≥ 50	X							
01 02 02	and		X						
010302				X					
010402				X					
010502				X					
02 01 02	< 300				X				
02 02 01						X			
02 03 01							X		
03 01 02				X					
01 01 03	< 50	X							
01 02 03			X						
010302				X					
010402				X					
010502				X					
02 01 03					X				
02 02 02						X			
02 03 02							X		
03 01 03				X					
01 01 04	not							X	
01 02 04	relevant							X	
02 01 04								X	
02 02 03								X	
02 03 03								X	
03 01 04								X	

01 01 05	not relevant								X
01 02 05									X
02 01 05									X
02 02 04									X
02 03 04									X
03 01 05									X

X : indicates relevant combination

1 ACTIVITIES INCLUDED

This chapter covers emissions from combustion plants treated collectively as area sources. However, e.g. if only a few units exist and thus only little data is available, the individual approach may be preferable also for small combustion plants.

The subdivision of the SNAP activities according to CORINAIR90 concerning combustion plants takes into account two criteria:

- the economic sector concerning the use of energy:
  - public power and co-generation,
  - district heating,
  - commercial, institutional and residential combustion,
  - industrial combustion,

    (Note: process furnaces are allocated separately.)
- the technical characteristics:
  - the installed thermal capacity,
    - ≥ 50 to < 300 MW,
    - < 50 MW,
  - other combustion technologies,
    - gas turbines,
    - stationary engines.

The emissions considered in this section 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 technical characterisation of the combustion sources may be integrated according to the size and type of plants as well as on primary or secondary reduction measures.[1] Solid, liquid or gaseous fuels are used; whereby solid fuels comprise coal, coke, biomass and waste (as far as waste is used to generate heat or power). In addition a non-combustion process can be a source of ammonia emissions; namely the ammonia slip in connection with some NO_x abatement techniques.[1]

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[1] Note: Small combustion installations are seldomly equipped with secondary measures.

2 CONTRIBUTION TO TOTAL EMISSIONS

The contribution of area source emissions released by combustion plants to the total emissions in the countries of the CORINAIR90 inventory reported as areas sources is given as follows:

Table 1: Contributions of emissions from combustion plants as area sources to the total emissions of the CORINAIR90 inventory reported as area sources. See chapter ACOR for further information on CORINAIR 90 emissions for these SNAP activities taking point and area sources together

		Contribution to total emissions [%]							
Source category	SNAP code	SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3
≥ 300 MW	01 01 01 01 02 01 03 01 01	0	0	0	0	0	0	-	0
50-300 MW	01 01 02 01 02 02 02 01 02 02 02 01 02 03 01 03 01 02	12.1	10.0	1.0	0.1	2.3	9.3	3.3	0.5
< 50 MW	01 01 03 01 02 03 02 01 03 02 02 02 02 03 02 03 01 03	71.3	46.7	41.1	7.2	49.8	66.4	21.8	0.7
Gas turbines	01 01 04 01 02 04 02 01 04 02 02 03 02 03 03 03 01 04	0.1	2.0	0.03	0.03	0.1	1.0	0.2	-
Stationary engines	01 01 05 01 02 05 02 01 05 02 02 04 02 03 04 03 01 05	0.6	2.0	0.2	0.02	0.1	0.4	0.2	0

- : no emissions are reported as area sources

0 : emissions are reported, but the exact amount is under the rounding limit

Plants with a thermal capacity < 50 MW are the major contributors. In particular, the contribution of small units in „Commercial, institutional and residential combustion“ with a thermal capacity < 50 MW (SNAP 020002) is significantly high: SO_x 37.0 %, NO_x 24.2 %, NMVOC 39.6 %, CH_4 6.9 %, CO 46.3 %, CO_2 44.4 %, N_2O 14.7 % and NH_3 0.6 % (related to total emissions of CORINAIR90 reported as area sources).

In the literature concerning heavy metal emissions in Europe, area source emissions are not reported separately. In order to show the relevance of the sector residential combustion, the share of the emissions of different heavy metals from this sector in the total emission in Germany is shown as an example in Table 2.

Table 2: Contribution of heavy metal emissions from residential combustion to national total emissions of former West Germany /1/

	Contribution in [wt.-%]	
Pollutant	**1982**	**1990**
As	5.8	15
Cd	3	4.4
Cr	n.d.	n.d.
Cu	4.2	6.4
Hg	1.9	2.8
Ni	4.5	7.7
Pb	0.2	0.4
Se	0.8	3.1
Zn	0.4	0.7

n.d. : no data are available

For Cd and Hg data are also available for Austria. The contribution to total emissions in 1992 was for Cd 38.4% and for Hg 27.8% /2/. The contribution of area sources, such as residential combustion, to total emissions has increased during recent years. This is caused by the fact that large emitters have been equipped with improved dust control facilities in Germany as well as in Austria, and hence the contribution from larger sources has been reduced.

3 GENERAL

3.1 Description

The emissions considered in this chapter are generated in boilers or in gas turbines and stationary engines regardless of the allocation of combustion plants to SNAP activities. In addition, residential combustion is relevant for this chapter. Emissions from process furnaces and from waste incineration are excluded.

3.2 Definitions

Integrated Coal Gasification Combined Cycle Gas Turbine (IGCC)	gas turbine fuelled by gas which is a product of a coal gasification process.
Boiler	any technical apparatus in which fuels are oxidised in order to generate heat for locally separate use.

Co-generation plant	steam production in (a) boiler(s) for both power generation (in a steam turbine) and heat supply.
Combined Cycle Gas Turbine (CCGT)	gas turbine combined with a steam turbine. The boiler can also be fuelled separately.
Furnace	fireplace in which fuels are oxidised to heat the direct surroundings.
Plant	element of the collective of emission sources (e.g. residential combustion) treated as an area source.
Stationary engines	spark-ignition engines or compression-ignition engines.

3.3 Techniques

3.3.1 Medium-sized combustion plants - boilers, gas turbines, stationary engines - (thermal capacity ≥ 50 and < 300 MW)

For the combustion of solid, liquid and gaseous fuels in medium-sized combustion plants techniques are used which have already been described in Section 3.3 of chapter B111 on “Combustion Plants as Point Sources”.

3.3.2 Small-sized combustion plants - boilers and furnaces - (thermal capacity < 50 MW)

Small sized combustion plants are divided here into industrial combustion and non-industrial combustion:

- Industrial combustion:
  The techniques used for the combustion of solid, liquid and gaseous fuels in industrial combustion plants have already been described in Section 3.3 of chapter B111 on “Combustion Plants as Point Sources“. The share of combustion techniques used is different: for the combustion of solid fuels mainly grate firing and stationary fluidised bed combustion are applied.

- Non-industrial combustion:
  Non-industrial combustion which includes other small consumers and residential combustion, is characterised by a great variety of combustion techniques.

  For the combustion of solid fuels e.g. mainly grate firing units are installed which can be distinguished by the type of stoking and the air supply. For example, in manually fed combustion units (such as single stoves) emissions mainly result from frequent start-ups/shut-downs; automatically fed combustion units are mainly emission relevant when the fuel is kept glowing. Normally, older combustion installations release more emissions than modern combustion installations. Furthermore, combustion installations which often operate with reduced load conditions are highly emission relevant: this operation mode occurs frequently in the case of over-dimensioned combustion units. /4, 5/

For the combustion of liquid and gaseous fuels, in principle similar technologies are applied, such as those described in chapter B111 on “Combustion Plants as Point Sources” (Section 3.3).

3.4 Emissions

Relevant pollutants are sulphur oxides (SO_x), nitrogen oxides (NO_x), carbon dioxide (CO_2), carbon monoxide (CO), non-methane volatile organic compounds (NMVOC), methane (CH_4) and heavy metals (arsenic (As), cadmium (Cd), chromium (Cr), copper (Cu), mercury (Hg), nickel (Ni), lead (Pb), selenium (Se), zinc (Zn) and in the case of heavy oil also vanadium (V)). Emissions of nitrous oxide (N_2O) and ammonia (NH_3) are normally of less importance.

The main influencing parameters which determine the emissions and species profiles of some pollutants are given in Sections 3.4 and 9 of chapter B111 on “Combustion Plants as Point Sources”. In particular for small combustion installations (e.g. residential combustion) emissions of NMVOC and CO can occur in considerable amounts; these emissions are mostly released from inefficiently working stoves (e.g. wood-burning stoves). VOC emissions released from domestic wood-fired boilers (0.5 - 10 MW) can be significant. Emissions can be up to ten times higher at 20 % load than those at maximum load /29/.

The emissions are released through the stack. The relevance of fugitive emissions (from seals etc.) can be neglected for combustion installations. Due to the fact that most references do not clearly distinguish between SO_x and SO_2, for the following sections it can be assumed that SO_2 includes SO_3, if not stated otherwise.

3.5 Controls

3.5.1 Medium-sized combustion plants - boilers, gas turbines, stationary engines - (thermal capacity ≥ 50 and < 300 MW)

It can be assumed, that the smaller the combustion installation considered are, the lower is the probability to be equipped with secondary measures. For cases where abatement technologies for SO_2, NO_X or heavy metals (controlled as particulates) are installed, the corresponding technical details are given in Section 3.5 of chapter B111 on “Combustion Plants as Point Sources”. For SO_2 abatement in Germany, larger boilers are mainly controlled by the limestone wet scrubbing process. In the case of smaller facilities dry sorption processes are preferred.

3.5.2 Small-sized combustion plants - boilers and furnaces - (thermal capacity < 50 MW)

Small-sized combustion plants have been split into industrial combustion and non-industrial combustion:

- Industrial combustion:

  For cases where abatement technologies for SO_2, NO_X or heavy metals are installed the corresponding technical details are given in Section 3.5 of chapter B111 on “Combustion Plants as Point Sources”. If NO_X reduction measures are installed mostly primary reduction measures (e.g. low NO_X burner) are applied.

- Non-industrial combustion:
  For small consumers / residential combustion only primary emission control measures are relevant. Emission reduction is mainly achieved by optimised operation conditions (older installations) and improved combustion efficiencies (modern installations).

4 SIMPLER METHODOLOGY

For combustion plants treated as area sources only a simpler methodology is given; a detailed methodology is not applicable (see Section 5). Here “simpler methodology“ refers to the calculation of emissions based on emission factors and activities and covers all relevant pollutants (SO_2, NO_x, NMVOC, CH_4, CO, CO_2, N_2O, heavy metals). Emissions of NH_3 are of less relevance (they are only released as ammonia slip in connection with secondary measures for NO_x abatement).

The annual emission E is determined by an activity A and an emission factor:

$$E_i = EF_i \cdot A \tag{1}$$

E_i annual emission of pollutant i
EF_i emission factor of pollutant i
A annual activity rate

The activity rate A and the emission factor EF_i have to be determined on the same level of aggregation depending on the availability of data. The activity A should be determined within the considered territorial unit by using adequate statistics (see also Section 6). The activity should refer to the energy input of the emission sources considered (fuel consumption in [GJ]). Alternatively, secondary statistics (surrogate data) can be used for the determination of the fuel consumption [GJ]. The quality of surrogate data can be characterised by two criteria:

- level of correlation
  The surrogate data should be directly related to the required data (e.g. fuel consumption of households derived from heat demand of households).

- level of aggregation
  The surrogate data should be provided on the same level of aggregation (e.g. spatial, sectoral and seasonal resolution).

Examples for activity rate and surrogate data and origins of possible inaccuracies are listed in the following:

- annual fuel consumption (recommended activity rate):
  - Statistics concerning the annual fuel consumption are often not further specified for different economic branches, and emission source categories, respectively. Furthermore, no technical split can be provided.

- annual fuel production [Gg], e.g. production of hard coal, lignite, natural gas:
  - The specifications of the fuel used (e.g. different types of coal) are not given. For the conversion of the unit [Gg] into unit [GJ] only an average heating value can be used.

- density of population, number of households:
    - Population statistics correspond to a very high level of aggregation. Further information has to be used (e.g. percentages of fuel consumed) in order to determine the activity rate for small consumers (e.g. residential combustion). In particular for fuels which are distributed by pipelines (e.g. natural gas) this assessment leads to an uncertainty in the activity rate determined.
- number of enterprises, number of employees, turnover of enterprises [Mio ECU]:
    - The statistical data on enterprise level are often allocated to the economic sector (e.g. “Production and Distribution of Electric Power, Production and Distribution of Steam, Hot Water, Compressed Air, District Heating Plants” /EUROSTAT, see Section 6/). On the other hand, emission factors are specified with regard to the type of fuel and often also to the type of boiler used.
- heat consumption:
    - The specific heat consumption per capita (e.g. [J/employee], [J/inhabitant]) or related to the area heated (e.g. [J/building], [J/m²]) can be determined by using area and branch specific data (e.g. differentiation between branches, number of employees, number of inhabitants).

The emission factor EF_i should be calculated as a mean value of all combustion installations within the territorial unit considered. In practice, a limited number of installations are selected to determine a representative emission factor which is applied to the total population of the installations considered. Usually, such emission factors are only specified as a function of fuel characteristics. However, further parameters should be taken into account, in particular the technology distribution as well as the size and age distribution of the boilers. Furthermore, evidence has been given that emissions are significantly affected by the operating conditions (e.g. inefficiently working stoves).

The emission factor EF_i (see Equation (1)) takes into account abatement measures (primary and secondary). If not stated otherwise the emission factors presented refer to full load conditions.

In the following a calculation procedure for SO_2 emission factors is proposed according to Equation (2):

$$EF_{SO_2} = 2 \cdot \overline{C}_{S_{fuel}} \cdot (1 - \overline{\alpha}_s) \cdot \frac{1}{\overline{H}_u} \cdot 10^6 \qquad (2)$$

EF_{SO_2}	emission factor for SO_2 [g/GJ]
$\overline{C}_{S_{fuel}}$	average sulphur content of fuel (in mass S/mass fuel [kg/kg])
$\overline{H}_u$	average lower heating value [Mg/kg]
$\overline{\alpha}_s$	average sulphur retention in ash [ ]

In cases where secondary reduction measures are installed, the reduction efficiency has to be integrated by applying one of the following assumptions:

- if the total population of combustion installations is equipped with secondary measures, a mean reduction efficiency of these measures should be used;

- if only few combustion installations are equipped with secondary measures, either these installations should be treated separately or the mean reduction efficiency should be calculated with regard to the total population.

Reduction efficiencies for different individual secondary measures are given in Tables 10 and 11 in chapter B111 on “Combustion Plants as Point Sources”.

Equation (2) can be used for all fuels, but for liquid and gaseous fuels the sulphur retention in ash α_s is not relevant. If certain input data of Equation (2) are not available, provided default values based on literature data can be used:

$\overline{C}_{S_{fuel}}$	sulphur contents of different fuels see Table 4[2] (in Section 8),
$\overline{\alpha}_S$	sulphur retention in ash of different types of boiler see Table 8[2] in chapter B111 on “Combustion Plants as Point Sources“,
$\overline{H}_u$	lower heating values of different types of fuels see Table 21[2] in chapter B111 on “Combustion Plants as Point Sources“.

For other pollutants, according to Equation (1) fuel and technology specific emission factors EF_i are given in Tables 5 - 12 based on literature data; for activity data see Section 6.

5 DETAILED METHODOLOGY

For combustion plants a detailed methodology means the determination of emissions based on measured data. This is not applicable to area sources as only few emission sources are monitored directly.

6 RELEVANT ACTIVITY STATISTICS

The following gives a list of available statistics on a national level for the determination of fuel consumption, installed capacities, socio-economic data, etc.:

- Office for Official Publication of the European Communities (ed.): Annual Statistics 1990; Luxembourg; 1992
- Statistical Office of the European Communities (EUROSTAT) (ed.): CRONOS Databank; 1993
- OECD (ed.): Environmental Data, Données OCDE sur l’environnement; Compendium; 1993
- Commission of the European Communities (ed.): Energy in Europe; 1993 - Annual Energy Review; Special Issue; Brussels; 1994
- EUROSTAT (ed.): Panorama of EU Industry’94; Office for official publications of the European Communities; Luxembourg; 1994

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[2] A mean value has to be calcutated with regard to the area concerned.

A brief discussion of potential surrogate data for the determination of the activity rate is given in Section 4.

7 POINT SOURCE CRITERIA

This section is not relevant since this chapter only covers area sources.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

8.1 Medium-sized combustion plants (thermal capacity ≥ 50 and < 300 MW)

For medium combustion installations, emission factors for the pollutants NO_x, NMVOC, CH_4, CO, CO_2, N_2O and heavy metals are given in Tables 24 - 31 in chapter B111 on “Combustion Plants as Point Sources”.

8.2 Small-sized combustion plants (thermal capacity < 50 MW)

Tables 4 - 12 contain emission factors for all pollutants except for SO_2 where sulphur contents of different fuels are given. All emission factor tables have been designed in a homogeneous structure: Table 3 provides a split of combustion techniques (types of boilers, etc.); this standard table has been used for all pollutants. The selection of fuels is based on the CORINAIR90 inventory.

For small-sized combustion installations, emission factors are given related to the type of fuel consumed and, if useful, related to technical specifications based on literature data. These emission factors normally refer to stationary operating conditions. Modifications are indicated as footnotes (instationary conditions e.g. due to manually fed boilers, etc.).

The sequence of the following emission factor tables is:

Table 3:	Standard table for emission factors for different pollutants
Table 4:	Sulphur contents of selected fuels
Table 5:	NO_x emission factors [g/GJ]
Table 6:	NMVOC emission factors [g/GJ]
Table 7:	CH_4 emission factors [g/GJ]
Table 8:	CO emission factors [g/GJ]
Table 9:	CO_2 emission factors [kg/GJ]
Table 10:	N_2O emission factors [g/GJ]
Table 11:	NH_3 emission factors [g/GJ]
Table 12:	Heavy metal emission factors (mass pollutant/mass fuel [g/Mg])

Table 3: Standard table of emission factors for the relevant pollutants

Fuel category1)				NAPFUE code1)	P12)	no technical specification	Technical specification									
							Industrial combustion							Non-industrial combustion		
							no specification10)	DBB3)	WBB4)	FBC5)	GF6)	GT7)	Stat. E.8)	no specification	Small consumers	Residential combustion9)
s	coal		no specification	-												
s	coal	hc11)		101 - 103												
s	coal	bc11)		106												
...	...	...	...	...												
s	biomass		wood	111												
...	...		...	...												
s	waste		municipal	114												
...	...		...	...												
l	oil		no specification	-												
l	oil		residual	201												
...	...		...	...												
g	gas		no specification	-												
g	gas		natural	301												
...	...		...	...												

1) the fuel category is based on the NAPFUE-code

2) P1 = sulphur content of fuel

3) DBB = Dry bottom boiler

4) WBB = Wet bottom boiler

5) FBC = Fluidised bed combustion

6) GF = Grate firing; ST1, ST2 = Type of stoker

7) GT = Gas turbine

8) Stat. E. = Stationary engine

9) A differentiation between old and modern techniques can be made for the ranges of emission factors given so that e.g. the smaller values relate to modern units.

10) Here only related to combustion in boilers; gas turbines and stationary engines are excluded.

11) hc = hard coal, bc = brown coal

Table 4: Sulphur contents of selected fuels

Fuel category				NAPFUE code	Sulphur content of fuel	
					range	unit
s	coal	hc	coking, steam, sub-bituminous	101 - 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		
s	coke	hc, bc	coke oven, petroleum	107, 108, 110	0.5 - 1 [1][2]	wt.-% (maf)
s	biomass		wood	111	< 0.03[1]	wt.-% (maf)
s	biomass		peat	113		
s	waste		municipal	114		
s	waste		industrial	115		
l	oil		residual	203	0.3[3] - 3.5[4]	wt.-%
l	oil		gas	204	0.08 - 1.0	wt.-%
l	oil		diesel	205		
l	kerosene			206		
l	gasoline		motor	208	< 0.05[5]	wt.-%
g	gas		natural	301		
g	gas		liquified petroleum gas	303		
g	gas		coke oven	304		
g	gas		blast furnace	305		
g	gas		refinery	308	<= 8[6]	$g \cdot m^{-3}$
g	gas		gas works	311		

[1] Marutzky 1989 /25/

[2] Boelitz 1993 /24/

[3] Personal communication Mr. Hietamäki (Finland)

[4] Referring to NL-handbook 1988 /26/ the range is 2.0 - 3.5

[5] $\alpha_S = 0$

[6] NL-handbook 1988 /26/

Table 5: NO_x emission factors [g/GJ]

					no technical specification	Technical specification									
						Industrial combustion							Non-industrial combustion		
Fuel category				NAPFUE code		no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-											60-232***
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	50 - 668[11]	155[13]							50[1][2]	150[9]	50[9]
s	coal	bc	brown coal/lignite	105	7.5 - 604[11]								12[2] - 100[1]		
s	coal	bc	briquettes	106	17 - 300[11]										100[9]
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	13 - 323[11]								45	50[9] [10]	50[9] [10]
s	biomass		wood	111	130 - 968[11]	206[13]				100-300*, 30-120**			12 - 80[1]	75[9]	50[9], 147-200[4]
s	biomass		peat	113	130 - 240[11]								100[1]		
s	waste		municipal	114	140 - 280[11]										
s	waste		industrial	115	100 - 193[11]										
s	waste		wood	116	80 - 258[11]										
s	waste		agricultural	117	80 - 100[11]										
l	oil		no specification	-									50[2]		
l	oil		residual	203	98 - 520[11]	165[13]					350[12]	75 - 1,889[12]			
l	oil		gas	204	55 - 1,624[11]	70[13]					100 - 531[12]	80 - 1,493[12]	50[1], 51[4]	48[9]	47[9]
l	oil		diesel	205	300 - 373[11]						380[12]	840[12],[13]			
l	kerosene			206	45 - 100[11]						120[12]	45 - 1,038[12]	50[1]		
l	gasoline		motor	208	80[11]							375[12]			
l	naphtha			210	24 - 1,085[11]										
g	gas		no specification	-									30[2]-50[3]		
g	gas		natural	301	32 - 307[11]	62[13]					81 - 360[12], 165[13][14]	75 - 1,200[12], 165[13]	50[1]	38[9]	30[8], 46[9]
g	gas		liquified petroleum gas	303	18 - 105[11]						120[12]		50[1],	57[9]	47[4], 69[9]
g	gas		coke oven	304	2 - 399[11]						250[12]		50[1]	38[9]	46[9]
g	gas		blast furnace	305	25 - 1,520[11]						250[12]				
g	gas		waste	307	52 - 238[11]										
g	gas		refinery	308	65 - 155[11]						55 - 357[12]				
g	gas		biogas	309	4 - 132[11]										
g	gas		from gas works	311	50 - 411[11]								50[1]		

[1] CORINAIR 1992 /8/
[2] LIS 1977 /15/
[3] UBA 1981 /21/, Kolar 1990 /14/
[4] Radian 1990 /18/, IPCC 1994 /12/
[11] CORINAIR90 data of combustion plants as area sources
[12] CORINAIR90 data, area sources
[13] UBA 1995 /30/
[14] at 50 % load: 130 g/GJ

[5] spruce wood
[6] chip board, phenol bonded
[7] chip board, urea bonded
[8] LIS 1987 /16/

[9] UBA 1995 /23/
[10] coke from hard coal

* 100[3] [5], 120[3] [6], 300[3] [7] for underfeed stoker
** 30[3] [5], 80[3] [6], 120[3] [7] for overfeed stoker
*** 60[8], 149[4], 232[4]

Table 6: NMVOC emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification									
						Industrial combustion							Non-industrial combustion		
						no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-											
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	1-511[5]								400[1] - 600[2]		50[3]
s	coal	bc	brown coal/lignite	105	1-800[5]										
s	coal	bc	briquettes	106	1.5-700[5]								150[1] [2]		225[3]
s		hc,bc	coke oven, petroleum	107,108, 110	0.5-700[5]								12[2]		225[3] [4]
s	biomass		wood	111	7-1,000[5]								150[2] - 800[1]		480[3]
s	biomass		peat	113	3-600[5]								150[1]		
s	waste		municipal	114	9-70[5]										
s	waste		industrial	115	0.5-134[5]										
s	waste		wood	116	48-600[5]										
s	waste		agricultural	117	50-600[5]										
l	oil		no specification	-									15[2]		
l	oil		residual	203	2.1-34[5]						3 - 4[6]	1.4 - 103.7[6]			
l	oil		gas	204	1.5-116[5]						0.7 - 5[6]	1.5 - 250[6]	15[1]		1.5[3]
l	oil		diesel	205	1.5-2.5[5]						5[6]	3.5[6]			
l	kerosene			206	1-14[5]						1[6]	1.5 - 244[6]	15[1]		
l	gasoline		motor	208	2[5]							437[6]			
l	naphtha			210	1-5[5]										
g	gas		no specification	-									1.5[2]		
g	gas		natural	301	0.3-205[5]						0.1 - 5.7[6]	0.3 - 47[6]	10[1]		2.5[3]
g	gas		liquified petroleum gas	303	0.3-14[5]						1[6]				3.5[3]
g	gas		coke oven	304	0.3-12[5]						2[6]		25[1]		2.5[3]
g	gas		blast furnace	305	0.2-1.5[5]										
g	gas		waste	307	2-16[5]										
g	gas		refinery	308	0.3-2.5[5]						2[6]				
g	gas		biogas	309	2.4-10[5]										
g	gas		from gas works	311	0.6-10[5]								25[1]		

[1] CORINAIR 1992 /8/

[2] LIS 1977 /15/

[3] UBA 1995 /23/

[4] coke from hard coal

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

[6] CORINAIR90 data, area sources

Table 7: CH_4 emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification									
						Industrial combustion							Non-industrial Combustion		
						no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-											
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	2 - 511[4]										450[2]
s	coal	bc	brown coal/lignite	105	0.2 - 532[4]										
s	coal	bc	briquettes	106	1 - 350[4]										225[2]
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	1.5 - 200[4]										225[2] [3]
s	biomass		wood	111	21 - 601[4]										74-200[1], 320[2]
s	biomass		peat	113	5 - 400[4]										
s	waste		municipal	114	6 - 32[4]										
s	waste		industrial	115	0.3 - 38[4]										
s	waste		wood	116	30 - 400[4]										
s	waste		agricultural	117	10 - 400[4]										
l	oil		no specification	-											
l	oil		residual	203	0.1 - 10[4]						1 - 3[5]	0,02 - 7,5[5]			
l	oil		gas	204	0.1 - 19[4]						1 - 20,9[5]	0,04 - 14[5]			3.5[2], 5[1]
l	oil		diesel	205	1.5 - 2.5[4]							3,5[5]			
l	kerosene			206	0.02 - 7[4]						1[5]	0,02 - 7,4[5]			
l	gasoline		motor	208	1							49[5]			
l	naphtha			210	0.02 - 5[4]										
g	gas		no specification	-									1[1]		
g	gas		natural	301	0.3 - 205[4]						0,3 - 22,5[5]	0,02 - 153[5]			2.5[2]
g	gas		liquified petroleum gas	303	0.02 - 6[4]						1[5]				1.1[1], 1.5[2]
g	gas		coke oven	304	0.02 - 12[4]						2[5]				2.5[2]
g	gas		blast furnace	305	0.02 - 4[4]										
g	gas		waste	307	0.4 - 2.5[4]										
g	gas		refinery	308	0.02 - 2.5[4]						2[5]				
g	gas		biogas	309	0.4 - 10[4]										
g	gas		from gas works	311	0.6 - 10[4]										

[1] Radian 1990 /18/, IPCC 1994 /12/

[2] UBA 1995 /23/

[3] coke from hard coal

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

[5] CORINAIR90 data, area sources

Table 8: CO emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification									
						Industrial combustion						Non-industrial Combustion			
						no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-						178-196*, 100[2]-107[6]			185[5]		160-3,580**
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	9 - 5,000[11]	73[13]								500[9]	4,800[9]
s	coal	bc	brown coal/lignite	105	4 - 6,000[11]										
s	coal	bc	briquettes	106	11 - 5,200[11]								7,000[7]		4,300[9]
s	coke	hc,bc	coke oven, petroleum		2 - 5,500[11]									1,000[9] [10]	4,800[9] [10]
s	biomass		wood	111	82 - 10,000[11]	627[13]							7,000[7]	3,600[9]	5,790[9]
s	biomass		peat	113	65 - 10,000[11]										18-18,533***
s	waste		municipal	114	33 - 2,188[11]										
s	waste		industrial	115	15 - 510[11]										
s	waste		wood	116	61 - 8,500[11]										
s	waste		agricultural	117	200 - 8,500[11]										
l	oil		no specification	-									70[8]		
l	oil		residual	203	29 - 1,754[11]	10[13]					10 - 30.4[12]	11.7 - 438[12]	20[2]		13[4]
l	oil		gas	204	5.3 - 547[11]	10[13]					10 - 123[12]	12 - 691[12]		41[9]	43[9]
l	oil		diesel	205	12 - 547[11]						12[12]	190[12],[13]			
l	kerosene			206	3 - 151[11]						12[12]	3.4 - 669[12]			
l	gasoline		motor	208	12[11]										
l	naphtha			210	0.2 - 89[11]										
g	gas		no specification	-									70[8]		10[4]
g	gas		natural	301	2.4 - 500[11]	10[13]					8-123[12], 10[13][14]	2.4-335[12], 136[13]	25[2]	41[9]	25-250***
g	gas		liquified petroleum gas	303	3.3 - 250[11]									41[9]	10[4], 53[9]
g	gas		coke oven	304	3.3 - 279[11]						13[12]			41[9]	53[9]
g	gas		blast furnace	305	3 - 279[11]						13[12]				
g	gas		waste	307	8.8 - 27[11]										
g	gas		refinery	308	3.3 - 279[11]						2[12]				
g	gas		biogas	309	7.8 - 41[11]										
g	gas		from gas works	311	6.4 - 225[11]										

[1] EPA 1987 /10/, CORINAIR 1992 /8/

[2] CORINAIR 1992 /8/ for overfed stoker

[3] OECD 1989 /31/, CORINAIR 1992 /8/

[4] Radian 1990 /18/, IPCC 1994 /12/

[5] EPA 1987 /10/, CORINAIR 1992 /8/

[6] EPA 1985 /9/, CORINAIR 1992 /8/ for overfeed stoker

[7] LIS 1987 /16/

[8] LIS 1977 /15/

[9] UBA 1995 /23/

[10] coke from hard coal

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

[12] CORINAIR90 data, area sources

[13] UBA 1995 /30/

[14] at 50 % load: 76 g/GJ

* 178[1], 190[2], 196[3] for underfeed stoker

**160[3], 484[4], 1,500[5], 1,607[6], 2,000[2], 3,400[3], 3,580[4]

*** 18[4], 53[9],4,949[4], 6,002[4], 18,533[4]

**** 25[2], 200[2], 250[2] (cooker)

Table 9: CO_2 emission factors [kg/GJ]

Fuel category				NAPFUE code	Emission factors value	range	remarks
s	coal		no specification	-			
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	94[6]	93 - 99[5], 55.9 - 106.8[2]	
s	coal	bc	brown coal/lignite	105		74 - 105.5[5], 67.5 - 116[2]	
s	coal	bc	briquettes	106	97[6]	97 - 113[3], 85.6 - 110.9[2]	
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	105[6]	96 - 122[1][4], 85.6 - 151[2]	
s	biomass		wood	111		100 - 125[1][4], 83 - 322.6[2]	
s	biomass		peat	113		98 - 115[2]	
s	waste		municipal	114		109 - 141[1], 15 - 117[2]	
s	waste		industrial	115		20 - 153.3[2]	
s	waste		wood	116		83 - 92[2]	
s	waste		agricultural	117		69 - 100[2]	
l	oil		no specification	-			
l	oil		residual	203		76 - 78[3][4], 64 - 99[2]	
l	oil		gas	204	74[6]	73 - 74[5], 69 - 97[2]	
l	oil		diesel	205		73 - 74[2][4]	
l	kerosene			206	73[5]	67.7 - 78.6[2]	
l	gasoline		motor	208	71[2], 73[5]	71 - 74[1][3][4]	
l	naphtha			210	73[3]	72.1 - 74[2]	
g	gas		no specification	-			
g	gas		natural	301	56[6]	55 - 61[3][4][5], 52 - 72[2]	
g	gas		liquified petroleum gas	303	65[6]	55 - 75.5[2]	
g	gas		coke oven	304	44[6], 49[5]	44 - 192[2]	
g	gas		blast furnace	305		105 - 290[2]	
g	gas		waste	307		62.5 - 87.1[2]	
g	gas		refinery	308		55 - 66[2]	
g	gas		biogas	309		60 - 103.4[2]	
g	gas		from gas works	311		52 - 56[2]	

[1] Schenkel 1990 /20/

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

[3] IPCC 1993 /11/

[4] Kamm 1993 /13/

[5] BMU 1994 /7/

[6] UBA 1995 /30/

Table 10: N_2O emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification									
						Industrial combustion							Non-industrial combustion		
						no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-											
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	5 - 30 1)										
s	coal	bc	brown coal/lignite	105	1.4 - 18.2 1)										
s	coal	bc	briquettes	106	1.4 - 14 1)										
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	1.4 - 14 1)										
s	biomass		wood	111	1.6 - 20 1)										
s	biomass		peat	113	2 - 14 1)										
s	waste		municipal	114	4 1)										
s	waste		industrial	115	2 - 5.9 1)										
s	waste		wood	116	4 1)										
s	waste		agricultural	117	1.4 - 4 1)										
l	oil		no specification	-											
l	oil		residual	203	0.8 - 46.5 1)						2.5 - 25 2)	1.1 - 2.1 2)			
l	oil		gas	204	0.6 - 17.8 1)						0.5 - 25 2)	0.6 - 14 2)			
l	oil		diesel	205	2 - 15.7 1)						15.7 2)	2 - 4 2)			
l	kerosene			206	2 - 14 1)						14 2)	2 2)			
l	gasoline		motor	208	14 1)							2 2)			
l	naphtha			210	12 1)										
g	gas		no specification	-											
g	gas		natural	301	0.1 - 14 1)						0.1-3 2)	0.1-3 2)			
g	gas		liquified petroleum gas	303	1 - 14 1)						14 2)				
g	gas		coke oven	304	1 - 12 1)						3 2)				
g	gas		blast furnace	305	0.8 - 34.6 1)						3 2)				
g	gas		waste	307	3.7 - 5 1)										
g	gas		refinery	308	1.5 1)						3 2)				
g	gas		biogas	309	1.5 - 3.7 1)										
g	gas		from gas works	311	2 - 3 1)										

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

2) CORINAIR90 data, area sources

Table 11: NH_3 emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification	
						Gas turbines	Stationary engines
s	coal		no specification	-			
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	0.14 - 0.48$^{1)}$		
s	coal	bc	brown coal/lignite	105	0.01 - 0.86$^{1)}$		
s	coal	bc	briquettes	106	0.01 - 0.86$^{1)}$		
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	0.01 - 0.86$^{1)}$		
s	biomass		wood	111	5 - 9$^{1)}$		
s	biomass		peat	113			
s	waste		municipal	114			
s	waste		industrial	115			
s	waste		wood	116			
s	waste		agricultural	117			
l	oil		no specification	-			
l	oil		residual	203	0.01$^{1)}$		
l	oil		gas	204	0.01 - 2.68$^{1)}$		0.1 - 0.2$^{1)}$
l	oil		diesel	205			
l	kerosene			206			0.2$^{1)}$
l	gasoline		motor	208			
l	naphtha			210			
g	gas		no specification	-			
g	gas		natural	301	0.15 - 1$^{1)}$		
g	gas		liquified petroleum gas	303	0.01$^{1)}$		
g	gas		coke oven	304	0.87$^{1)}$		
g	gas		blast furnace	305			
g	gas		waste	307			
g	gas		refinery	308			
g	gas		biogas	309	15$^{1)}$		
g	gas		from gas works	311			

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

Table 12: Heavy metal emission factors (mass pollutant/mass fuel [g/Mg])

Fuel category			NAPFUE code	Heavy metal element	no technical specification	Technical specification							
						Industrial combustion					Non-industrial combustion		
						no specification	DBB	WBB	FBC	GF	no specification	Small consumer	Residential combustion
s	coal	hc	101/102	Mercury		1.7 g/TJ[2]							0.3[1]
				Cadmium		0.1 g/TJ[2]							0.15[1]
				Lead		6.0 g/TJ[2]							2.5[1]
				Copper		3.1 g/TJ[2]							1.2[1]
				Zinc		10.5 g/TJ[2]							1[1]
				Arsenic		3.2 g/TJ[2]							1.2[1]
				Chromium		2.3 g/TJ[2]							0.9[1]
				Selen		0.5 g/TJ[2]							0.15[1]
				Nickel		4.4 g/TJ[2]							1.8[1]
s	coal	bc	105	Mercury		4.4 g/TJ[2]							0.1[2]
				Cadmium		0.4 g/TJ[2]							0. 04[2]
				Lead		3.9 g/TJ[2]							0.24[2]
				Copper		2.0 g/TJ[2]							
				Zinc		10.6 g/TJ[2]							0.14[2]
				Arsenic		4.2 g/TJ[2]							
				Chromium		3.1 g/TJ[2]							
				Selen									
				Nickel		3.9 g/TJ[2]							
l	oil, heavy fuel		203	Mercury		0.15-0.2[1]							
				Cadmium		0.1-1[1]							
				Lead		0.6-1.3[1]							
				Copper		0.05-1[1]							
				Zinc		0.02-0.2[1]							
				Arsenic		0.14-1[1]							
				Chromium		0.2-2.5[1]							
				Selen		0.003-1[1]							
				Nickel		17-35[1]							
g	gas		301	Mercury									

[1] Winiwarter 1995 /6/

[2] Jockel 1995 /1/

9 SPECIES PROFILES

For species profiles of selected pollutants see Section 9 in chapter B111 on “Combustion Plants as Point Sources”.

10 UNCERTAINTY ESTIMATES

Uncertainties of emission data result from inappropriate emission factors and from missing statistical information on the emission generating activity. Those discussed here are related to emission factors. Usually uncertainties associated with emission factors can be assessed by comparing them with emission factors obtained by using measured data or other literature data. However, at this stage, the available emission factors based on literature data are often poorly documented without a specification concerning the area of application. A range of emission factors, depending on the parameters available (as given in chapter B111 on “Combustion Plants as Point Sources“, Section 10), can therefore not be given here.

11 WEAKEST ASPECTS / PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

Weakest aspects discussed here are related to emission factors.

The average emission factor of a territorial unit should integrate the diversity of the combustion techniques installed within the territorial unit. Therefore, the number and diversity of the selected combustion installations for the calculation of the average emission factor should correspond with the number and diversity of the installations within the territorial unit (target population). Further work should be carried out to characterise territorial units with regard to the technologies in place (technology distribution, age distribution of combustion technique, etc.).

For all pollutants considered, neither qualitative nor quantitative load dependencies have yet been integrated into the emission factors. In particular for oil, coal and wood fired small stoves, increased emissions occur due to a high number of start-ups per year (e.g. up to 1,000 times a year) or due to load variations (e.g. manual furnace charging). Emissions from residential firing can be highly relevant (e.g. combustion of wood in the Nordic countries, in particular for VOC and CO emissions). Further work should be invested to clarify this influence with respect to the emission factors published.

For the weakest aspects related to the determination of activities based on surrogate data see Section 4. Uncertainty estimates of activity data should take into account the quality of available statistics. In particular, emissions from the combustion of wood in single stoves may increase as some national statistics have underestimated wood consumption to date /3/.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

Spatial disaggregation of annual emission data (top-down approach) can be related

- for industrial combustion e.g. to the number of industrial employees in industrial areas and
- for residential combustion e.g. to the number of inhabitants in high density and low density areas and to the type of fuel.

In general the following disaggregation steps for emissions released from residential combustion can be used /cf. 27/:

- differentiation in spatial areas, e.g. administrative units (country, province, district, etc.), inhabited areas, settlement areas (divided in high and low density settlements),
- determination of regional emission factor per capita depending on the population density and the type of fuel used.

For emissions released from industrial combustion, spatial disaggregation takes into account the following steps:

- differentiation in spatial areas with regard to industrial areas,
- determination of emission factors related to the number of industrial employees.

13 TEMPORAL DISAGGREGATION CRITERIA

Temporal disaggregation of annual emission data (top-down approach) provides a split into monthly, weekly, daily and/or hourly emission data. For annual emissions released from combustion plants as area sources this data can be obtained for:

- industrial combustion by using in principle the disaggregation criteria and the procedure as described in Section 13 of chapter B111 on “Combustion Plants as Point Sources” by taking into account the number of plants in the area considered.
- non-industrial combustion (small consumer/residential combustion) by using a relation between the consumption of fuel and the heating degree-days.

The disaggregation of annual emissions released from non-industrial combustion (small consumers/residential combustion) has to take into account a split into:

- summer and winter time (heating periods),
- working days and holidays and
- daily fluctuations of load

for the main relevant fuels and, if possible, for the main relevant combustion techniques (manually fed stoves, etc.)

The procedure of disaggregation consists of the following step-by-step approach /cf. 28/:

- determination of the temporal variation of the heat consumption (based e.g. on user behaviour),
- determination of the fuel consumption e.g. by using statistics for district heat or consumption of gas, by using fuel balances for the estimation of coal and wood consumption (e.g. as given in /3/),

- correlation of the heating degree-days with the consumption of fuel (e.g. for gas, district heat). Typical heating degree-days are available in statistics. The correlation can be linear as given e.g. in /28/.
- determination of the relative activity (e.g. fuel consumption per hour per day) by using adequate statistics.

This approach makes it possible to determine annual, weekly and/or daily correction factors. For the determination of hourly emissions the following Equation (3) /cf. 28/ can be given as an example:

$$E_H(t) = \frac{E_A}{8,760\left[h\right]} \cdot f_a(t) \cdot f_w(t) \cdot f_d(t) \qquad (3)$$

E_H	emission per hour(s) [Mg/h]
E_A	annual emission [Mg]
f_a	annual correction factor [ ]
f_w	weekly correction factor [ ]
f_d	daily correction factor [ ]
t	time

The constant (8,760 h) in Equation (3) represents the number of hours per year.

14 ADDITIONAL COMMENTS

15 SUPPLEMENTARY DOCUMENTS

16 VERIFICATION PROCEDURES

As outlined in chapter B111 on ”Concepts for Emission Inventory Verification“ different verification procedures can be used. The aim of this section is to select those which are most adequate for emission data from combustion plants as area sources. Verification procedures considered here are principally based on the verification of emission data on a territorial unit level (national level).

The annual emissions related to a territorial unit can be compared to independently derived emission estimates. These independent emission estimates can be obtained by using econometric relations between annual emissions and exogenous variables, such as population equivalents, number of households, fossil fuel prices, etc.

Another possibility is to make emission density comparisons of e.g. emissions per capita or emissions per GDP between countries with comparable economic structures.

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19 RELEASE VERSION, DATE AND SOURCE

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Annex 1: List of abbreviations

A_i	Activity rate of the emission source i
bc	Brown coal
CCGT	Combined Cycle Gas Turbine
CFBC	Circulating Fluidised Bed Combustion
DBB	Dry Bottom Boiler
E	Emission
EF_i	Emission factor of the emission source i, e.g. in [g/GJ]
f_a	Annual correction factor [ ]
f_d	Daily correction factor [ ]
f_w	Weekly correction factor [ ]
FBC	Fluidised Bed Combustion
g	Gaseous state of aggregation
GF	Grate Firing
GT	Gas Turbine
H	Lower heating value of fuel
hc	Hard coal
IGCC	Integrated Coal Gasification Combined Cycle Gas Turbine
l	Liquid state of aggregation
PFBC	Pressurised Fluidised Bed Combustion
s	Solid state of aggregation
S	Sulphur content of fuel
Stat. E.	Stationary Engine
t	Time
WBB	Wet Bottom Boiler

SNAP CODE:	**010104** **010204** **010304** **010404** **010504** **020104** **020203** **020303** **030104**
SOURCE ACTIVITY TITLE:	**Gas Turbines**
NOSE CODE:	**101.04**

1 ACTIVITIES INCLUDED

Gas turbine plant fall within the following CORINAIR SNAP classification codes:

010104	Public power – gas turbines
010204	District heating plants – gas turbines
010304	Petroleum refining plants – gas turbines
010404	Solid fuel transformation plants – gas turbines
010504	Gas extraction/distribution – gas turbines
020104	Commercial and institutional plants – stationary gas turbines
020203	Residential plants – gas turbines
020303	Plants in agriculture, forestry and aquaculture – stationary gas turbines
030104	Combustion in industry – gas turbines

Emissions considered in this section are released by a controlled combustion process, taking into account primary reduction measures, such as furnace optimisation, the combustion chamber, and secondary reduction measures downstream of the combustion chamber.

2 CONTRIBUTION TO TOTAL EMISSIONS

This section covers emissions of SO_x, NO_x, CO, CO_2, NMVOC, CH_4, N_2O, NH_3 and heavy metals (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn, V). The contributions of emissions released by some categories of gas turbines to the total emissions in countries of the CORINAIR90 inventory are given as follows in Table 2.1:

Table 2.1 Contributions of emissions from combustion plants as point or area sources to total emissions of the CORINAIR90 inventory reported as point sources

		Contribution to total emissions [%]							
Source category	**SNAP90 code**	SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3
Gas turbines	01 01 04 01 02 04 02 02 03 03 01 04	0	0.39	0.07	0.06	0.05	0.35	0.02	-

0 = emissions are reported, but the exact value is below the rounding limit of 0.1 per cent
- = no emissions are reported

The most relevant pollutant emitted from gas turbines is nitrogen oxides (NO_x). Other relevant pollutants are carbon dioxide (CO_2), carbon monoxide (CO), and volatile organic compounds (non-methane VOC and methane (CH_4)) from older plant. Emissions of nitrous oxide (N_2O), sulphur oxides (SO_x), and ammonia (NH_3) are of less importance.

3 GENERAL

3.1 Description

A gas turbine is a type of internal combustion engine in which fuel is burnt with compressed air. Energy from the fuel combustion is recovered by a power turbine which drives a compressor turbine (which provides the compressed combustion air) and the external load.

Gas turbines are installed with a thermal capacity ranging from several hundred kW up to 500 MW. Gaseous fuels are mainly used, such as natural gas or the product of coal gasification (e.g. CCGT or IGCC installations) or other process gases. Also liquid fuels are used, such as light distillates (e.g. naphtha, kerosene or fuel oil) and in some cases other fuels (e.g. heavy fuel oil). Combustion temperatures of up to 1,300 °C in the combustion chambers may lead to considerable NO_X emissions.

3.2 Definitions

CCGT – Combined Cycle Gas Turbine Plants

IGCC – Integrated Coal Gasification Combined Cycle Gas Turbine Plants

SCR – Selective Catalytic Reduction

SNCR – Selective Non-Catalytic Reduction

3.3 Techniques

The load is typically an alternator or pipeline compressor in industrial use, or a fan or propeller in aircraft. Industrial gas turbines can have a single shaft (all components mounted on a single drive shaft) or may have two or three shafts. Aeroderivative industrial gas turbines have been developed from aircraft power units and tend to be lighter and more suitable for variable load than 'heavy' gas turbines.

Gas turbines used for gas transfer may operate frequently under part load conditions, where load control may be by shaft or generation output. However, gas turbines used for electricity generation are more often run under maximum load under combustor temperature control. Actual output under temperature control can be affected by ambient conditions (air temperature, pressure and humidity).

Open cycle, combined cycle and cogeneration plant

Open cycle gas turbines provide shaft power but are not fitted with heat recovery. Pipeline compressor engines and standby generators are generally open cycle systems. Although open cycle gas turbines for standby electricity generation are not uncommon, modern industrial gas turbines tend to be part of cogeneration plant, such as combined heat and power (CHP) plant, combined cycle gas turbine (CCGT) systems, or Integrated Coal Gasification Combined Cycle Gas Turbine (IGCC) Plants. In a CCGT plant, gas turbines are used to generate electricity and a heat recovery steam generator (boiler) is used to recover energy from the turbine exhaust gases. The steam produced is then used to generate more electricity using a steam turbine alternator set. For IGCC plants, the only emission-relevant unit is the gas turbine (combustion chamber); for CCGT, in addition to the gas turbine, any installed fossil fuelled boiler should also be taken into account.

A cogeneration plant also uses a gas turbine to generate electricity and can use the turbine exhaust gas for direct or indirect drying; or, more commonly, a waste heat boiler is employed for steam generation. In common with a CCGT plant the steam may be used to generate electricity, but in general the steam is required primarily for process use. Supplementary burners are commonly used in CHP plant to accommodate variable process steam demand.

3.4 Emissions

The most relevant pollutant emitted from gas turbines is nitrogen oxides (NO_x). Other relevant pollutants are sulphur oxides (SO_x), carbon dioxide (CO_2), and volatile organic compounds (non-methane VOC and methane (CH_4)) from older plant. Emissions of nitrous oxide (N_2O), carbon monoxide (CO) and ammonia (NH_3) are of less importance.

Emissions of POPs and heavy metals might be significant where heavy fuel oil is used.

3.5 Controls

Pollution control techniques for gas turbines have essentially targeted combustion efficiency and NO_x emissions. Various techniques have been employed for NO_x control, including the following:

- Steam injection;
- Water injection;
- low NO_x burner systems.

In addition, Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) systems have also been developed for NO_x control for larger gas turbines. Low NO_x burner systems are often termed dry control systems as they do not involve water or steam injection.

4 SIMPLER METHODOLOGY

The simpler methodology involves the calculation of emissions based on emission factors and activity data. The simpler methodology should only be used in cases where no measured data are available.

The annual emission is derived from an annual activity multiplied by an emission factor (Equation (1)):

$$\text{Annual emission} = \text{Annual activity x Emission factor} \qquad (1)$$

The activity rate and the emission factor have to be determined on the same level of aggregation by using available data (e.g. fuel consumption).

Differences in design and operation of gas turbines, in fuels used and/or controls installed require different emission factors. The default emission factors in section 8 take into account these parameters.

If not stated otherwise, the emission factors presented in Section 8 refer to full load conditions. Start-up emissions can be considered separately but are small for gas turbines.

5 DETAILED METHODOLOGY

In principle, plant specific measurement data should be used, if available, for the determination of emissions from gas turbines.

6 RELEVANT ACTIVITY STATISTICS

For the activity rate, the energy input in [GJ] should be used, but in principle other relations are also applicable.

Activity data on the number and size of gas turbines and the amount of fuel burned should be available from statistical offices of individual countries or from statistical reports from Eurostat or OECD. A list of example statistical reports is given in section 18.

7 POINT SOURCE CRITERIA

According to CORINAIR90, combustion plants with:

- a thermal capacity ≥ 300 MW, or
- emissions of SO_2 or NO_x or NMVOC > 1,000 Mg/a[1]

should be considered as point sources. Within CORINAIR other combustion plants may also be considered as point sources on a voluntary basis.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

In the absence of better data, the following default emission factors may be used:

Simple Methodology

Tables 8.1 to 8.4 give default emission factors for the most significant pollutants from SNAP categories 010104, 010504 and 030104, where available, for plant running on natural gas with varying levels of NO_x control:

- Uncontrolled;
- steam injection;
- water injection;
- dry low-NO_x burner.

Table 8.5 gives a summary of emission factors by SNAP codes.

Table 8.6 gives a summary of emission factors measured on plant of varying age in Italy.

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[1] For CO_2 a further optional criterion for point sources is the emission of > 300 Gg/a.

Table 8.1 Default Emission Factors for NO_x

NO_x Control	**NO_x emission factors, g GJ^{-1}**				
	Stewart 1998	**USEPA**		**EMEP/ CORINAIR**	**UK NAEI**
		Electricity	**Pipeline**		
Uncontrolled	104-312	189	146	160-480	-
				650 (aeroderivative)	
Steam injection	46-120	51.6	-	-	-
Water injection	115	60.2	-	-	-
Dry low NO_x burner	33-86	-	-	80	44

Notes :

1. NO_x is expressed as NO_2.
2. '-' denotes no data
3. USEPA emission factor data from AP-42 5th Ed including supplements A and B.
4. EMEP/CORINAIR emission factors from the Atmospheric Emission Inventory Guidebook and are data for point sources.
5. NAEI emission factors are for 1996 and represent gas-fired power stations.

Table 8.2 Default Emission Factors for CO

NO_x Control system	**CO emission factors, g GJ^{-1}**				
	Stewart 1998	**USEPA**		**EMEP/ CORINAIR**	**UK NAEI**
		Electricity	**Pipeline**		
Uncontrolled	<3-120	47.3	73.1	-	-
Steam injection	3-47	68.8	-	-	-
Water injection	20.8	120	-	-	-
Dry low NO_x burner	1.2-21	-	-	-	16

Notes :

1. '-' denotes no data.
2. USEPA emission factor data from AP-42 5th Ed including supplements A and B.
3. EMEP/CORINAIR emission factors from the Atmospheric Emission Inventory Guidebook and are data for point sources.
4. NAEI emission factors are for 1996 and represent gas-fired power stations.

Table 8.3 Default Emission Factors for VOCs

NO$_x$ Control system	**VOC emission factors, g GJ^{-1}**				
	Stewart 1998	**USEPA**		**EMEP/ CORINAIR**	**UK NAEI**
		Electricity	**Pipeline**		
Uncontrolled	1.1-25	10.3	22.8	2.5-6.1 (CH_4) 2.5-5 (NMVOC)	-
Steam injection	1.3-6.3	-	-	“	-
Water injection	2.8	-	-	“	-
Dry. Low NO$_x$ burner	0.6-2.6	-	-	“	6.0 (CH_4) 5.3 (NMVOC)

Notes:

1. ‘-’ denotes no data.
2. VOC are expressed as methane.
3. USEPA emission factor data from AP-42 5th Ed including supplements A and B.
4. EMEP/CORINAIR emission factors from the Atmospheric Emission Inventory Guidebook and are for no specified type of gas turbine are data for point sources.
5. NAEI emission factors are for 1996 and represent gas-fired power stations.

Table 8.4 Default Emission Factors for N_2O

NO$_x$ Control system	**N_2O emission factors, g GJ^{-1}**				
	Stewart 1998	**USEPA**		**EMEP/ CORINAIR**	**UK NAEI**
		Electricity	**Pipeline**		
Uncontrolled	2-6	-	-	-	-
Steam injection	3	1.29	-	-	-
Water injection	3	1.29	-	-	-
Dry. low NO$_x$ burner	1-7	-	-	-	3.7

Notes:

1. ‘-’ denotes no data.
2. USEPA emission factor data from AP-42 5th Ed including supplements A and B.
3. NAEI emission factors are for 1996 and represent gas-fired power stations.

Table 8.5 Summary of emission factors by SNAP codes (Stewart, 1998)

SNAP Code	Description	NO_x control	No of gas turbines in survey	Size of gas turbines MW	NO_x EFs g GJ^{-1}	CO EFs g GJ^{-1}	VOC EFs g GJ^{-1}	N_2O EFs g GJ^{-1}
010104	Public power, gas turbines	Low NO_x burner	4	150-215	33-86	1.2-21	0.6-2.6	1-7
		Steam injection	1	125	120	4.0	2.6	<9
		Uncontrolled	2	~25-125	198-250	6.6-51	1.1-4.2	<9
030104	Combustion in industry, gas turbines	Water injection	1	22	115	20.8	2.8	2
		Steam injection	2	4.8-40	46-91	3-47	1.3-6.3	2
		Uncontrolled	4	6.25-40	140-279	<3-14	1.6-3.0	<4-4
010504	Gas extraction / distribution, gas turbines	Uncontrolled	5	6.25-25	104-312	6-120	3.7-25	2-6

Notes :

1. NO_x is expressed as NO_2 .
2. VOC expressed as methane.
3. With the exception of the large CCGT gas turbines used for utility power generation, many of the gas turbines surveyed would be used in other industry sectors.

None of the pipeline compressor gas turbines, which were visited early in the measurement programme, were fitted with NO_x control systems.

Table 8.6 Summary of emission factors measured during the years 1997 and 1998, Italy (Caserini et al)

SNAP	Town	Unit number	Thermal Capacity (MW)	Fuel Cons. (GJ/year)	E.F.CO g/GJ	E.F.NOx g/GJ	Control system	Age of the plant (*)
010104	CASSANO D'ADDA	3	105	220,700	32	222	Steam injection	old
010204	SAN DONATO MILANESE	1	12	337,482	34	265	uncontrolled	old
010204	SAN DONATO MILANESE	2	12	247,068	34	263	uncontrolled	old
010104	TURBIGO	6	400	1,547,026	-	71	Dry low NOx	medium
010104	TURBIGO	7	400	2,336,386	-	77	Dry low NOx	medium
010104	TURBIGO	8	400	4,039,245	-	68	Dry low NOx	medium
010204	SAN DONATO MILANESE	3	15	392,070	5.9	157	Steam injection	medium
010204	SAN DONATO MILANESE	4	15	343,428	6.1	145	Steam injection	medium
010204	SESTO SAN GIOVANNI	1	120	3,409,998	16	39	Dry low NOx	new
010104	BOFFALORA SOPRA TICINO	1	205	1,766,430	5.7	20	Dry low NOx	new
010204	CREMONA	1	26	752,536	0.8	108	Steam injection	new

* old : 1970-1980; medium : 1980-1990; new: >1990

9 SPECIES PROFILES

Limited speciated data are available.

10 CURRENT UNCERTAINTY ESTIMATES

The emission factors in Section 8 have an uncertainty rating of B/C.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

The emission factors are not necessarily representative of all gas turbine plant and could be improved if more data were available for plants in different countries.

For NM VOCs, these plants contribute a low proportion of total emissions and the generation of speciated data for this source should not be a priority.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

In general the following disaggregation steps for emissions released from residential combustion can be used:

- differentiation in spatial areas, e.g. administrative units (country, province, district, etc.), inhabited areas, settlement areas (divided in high and low density settlements);
- determination of regional emission factor per capita depending on the population density and the type of fuel used.

For emissions released from industrial combustion, spatial disaggregation takes into account the following steps:

- differentiation in spatial areas with regard to industrial areas;
- determination of emission factors related to the number of industrial employees.

13 TEMPORAL DISAGGREGATION CRITERIA

Temporal disaggregation of annual emissions released from combustion plants as point sources or industrial plant as area sources can be obtained from the temporal change of the production of power or the temporal change of the consumption, taking into account a split into:

- summer and winter time;
- working days and holidays;
- standstill times;
- times of partial load behaviour;
- number of start-ups / type of load design.

For non-industrial combustion (small consumer/residential combustion) temporal disaggregation should take into account:

- consumption of fuel;
- heating degree-days;
- summer and winter time (heating periods);
- working days and holidays;
- daily fluctuations of load.

14 ADDITIONAL COMMENTS

No additional comments.

15 SUPPLEMENTARY DOCUMENTS

The combustion chapters of the 1st Edition of the EMEP/CORINAIR Atmospheric Emission Inventory Guidebook should be referred to for more detail.

16 VERIFICATION PROCEDURES

For verification purposes, annual emissions can be compared to independently derived emission estimates. These independent emission estimates can be obtained by using relations between annual emissions and variables such as population equivalents, number of households, fossil fuel prices, etc.

Another possibility for verification is to make emission density comparisons of e.g. emissions per capita or emissions per GDP between countries with comparable economic structures.

17 REFERENCES

Caserini, S. personal communication on behalf of Regione Lombardia - Servizio Protezione Ambientale e Sicurezza Industriale, Regional Plan for Air Quality - Emission Inventories Unit. Contact: Dott. Angelo Giudici, Ing. Stefano Caserini, Via Stresa 24, 20125 Milano (Italy). Tel +39 02 6765 6752/ 4857; Fax +39 02 6765 4961; E-mail: angelo_giudici@ regione.lombardia.it; stefano_caserini@ regione.lombardia.it

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EUROSTAT Demographic Statistics, Luxembourg

19 RELEASE VERSION, DATE AND SOURCE

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SNAP CODE :	**010302** **010303** **010304** **010305**
SOURCE ACTIVITY TITLE :	**Combustion Plants >= 50 and < 300 MW (boilers)** **Combustion Plants < 50 MW (boilers)** **Gas Turbines** **Stationary Engines**

A specific methodology for these activities has not been prepared because the contribution to total national emissions is thought to be currently insignificant, i.e. less than 1% of national emissions of any pollutant.

If you have information contrary to this please contact the expert panel leaders.

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SNAP CODE : 010306

SOURCE ACTIVITY TITLE: Process Furnaces

1 ACTIVITIES INCLUDED

This chapter covers emissions released from combustion processes within a refinery for the heating of crude and petroleum products without contact between flame and products. Primary reduction measures are taken into account (if installed). The emission generating process is the combustion of heavy fuel oil, refinery gas and/or petroleum coke. Thermal cracking units are also taken into account.

The following activities are excluded: power plants installed within a refinery (producing steam and/or electricity) as well as internal combustion engines and gas turbines are considered in chapters B111 on “Combustion Plants as Point Sources” and B112 on “Combustion Plants as Area Sources”; fluid catalytic cracking/CO boilers are treated under SNAP 040102; sulphur recovery plants are covered by SNAP 040103; flaring in the oil industry is treated under SNAP 090204 (waste treatment and disposal). Process specific emissions from refineries are covered by SNAP 040104 “Storage and Handling of Petroleum Products in a Refinery”.

2 CONTRIBUTION TO TOTAL EMISSIONS

The contribution of emissions released from refinery process furnaces to the total emissions in countries of the CORINAIR90 inventory is given as follows:

Table 1: Contribution to total emissions of the CORINAIR90 inventory (*28 countries*)

Source-activity	**SNAP-code ***	**Contribution to total emissions [%]**							
		SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3
Process Furnaces without Conctact	010306	1.4	0.5	0.2	0	0.1	1.0	0.2	-

0 = emissions are reported, but the exact value is below the rounding limit (0.1 per cent)
- = no emissions are reported
* = SNAP90 code 030201

In a modern refinery up to 80 %, in some cases even 90 %, of all SO_2 emissions and also a major part of the NO_x emissions and particulate emissions (combined with heavy metals) of the refinery are dependent or directly related to the types of fuel used and their respective shares of the total fuel consumption of the refinery /14/. A split of total refinery emissions can be given as an example for SO_2 and NO_x emissions (Western Europe) /cf. 1, 9/:

SO_2:	- Process heaters and boilers:	69 %	of total SO_2 emissions from refineries
	- FCC units (CO boilers):	7 %	”
	- sulphur recovery unit:	10 %	”
	- flares:	9 %	”
	- other sources (e.g. gas turbines, stationary engines):	6 %	”
NO_x:	- process heaters:	46 %	of total NO_x emissions from refineries
	- boilers:	17 %	”
	- FCC units (CO boilers):	16 %	”
	- engines (for pumps etc.):	11 %	”
	- gas turbines and combined cycle systems:	10 %	“

Process heaters contribute about 40 % to the total refinery emissions of SO_2 and NO_x, whereas the contribution of refineries to the total anthropogenic emissions is about 1 % (average for SO_2 and No_x).

3 GENERAL

3.1 Description

The most relevant emission sources within this sector are process heaters. In most refining processes it is necessary to apply heat to raise the temperature of the feedstock to a required temperature. Process heaters are therefore used, and where processes are self-contained each process usually has its own separate process heater.

3.2 Definitions

Cracking	one of the process steps within a refinery for splitting long-chain hydrocarbons into short-chain hydrocarbons. Two types of cracking can be distinguished: catalytic and thermal. Catalytic cracking (e.g. FCC) is the most common type of cracking implemented in refineries. Thermal cracking is of less importance with the exception of visbreaking (thermal cracking of high-boiling residues).

3.3 Techniques

Process heaters are installed as for example pipe still or pre-heaters; they are mostly located at the atmospheric distillation, before the vacuum distillation, before the visbreaker, before the FCC units, before thermal cracking units[3], and before the sulphur recovery units. The burners are mostly situated at the bottom of the installations. Refineries can have about 4 up to more than 40 process heaters depending on the complexity of operations. The refinery gas,

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[3] Thermal cracking units are of less importance within refineries, but they are commonly used in the petrol chemistry (e.g. olefin cracking units).

produced by petroleum processing, provides a significant part of the fuel for process heaters. Different processes contribute varying amounts and varying compositions to the refinery gas. However, major components of the gas are hydrogen and light hydrocarbons. In principle, refineries use gaseous fuels (refinery gas, sometimes also natural gas /14/), which are supplemented by liquid fuels (heavy fuel oil or other residues) and solid fuels (petroleum coke). In many applications, dual-fuel burners are used with gas and liquid fuel being consumed by the same burners. The columns can also be heated by using the process steam generated in boilers. The fuel used for steam generation may be different from commercial fuel as its nature is determined by the optimal use of resources within each refinery at a given time. /cf. 1, 3/.

3.4 Emissions

Relevant pollutants are sulphur oxides (SO_x), nitrogen oxides (NO_x) and carbon dioxide (CO_2). SO_3 emissions are negligible for all fuels used. For normal operating conditions emissions of carbon monoxide (CO), nitrous oxide (N_2O), and heavy metals are of less relevance. Emissions of volatile organic compounds (non-methane VOC and methane (CH_4)) can occur, but they are often negligible. Normally, emissions of ammonia (NH_3) are not relevant.

Emissions considered here are associated with continuous operation of the refinery. Emissions are released through stacks. Nevertheless, frequent start-ups and shut-downs of process heaters may occur, due to unexpected changes in operating conditions or from regular non-operating times (e.g. for maintenance).

The emissions of sulphur dioxide (SO_2) are directly related to the sulphur content of the fuel(s) used. The sulphur content of refinery gas varies from 0.01 to 5 %, averaging 0.8 % /2/. Refinery gases are produced in almost all hydrocarbon processing installations. They can be classified as sulphur-free gases and gases containing sulphur: /14/

- sources of sulphur-free gases: [4]
  - isomerisation plants, catalytic reforming plants, hydrogen manufacturing plants, gasification of coke in some coke operations,
- sources of sulphur-containing gases: [5]
  - crude distillation, hydro-treating/hydro-desulphurisation, catalytic cracking, thermal cracking/coking/visbreaking, residue conversion, flare gas recovery[6], gasification of coke from some coke operations /14/ [7]

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[4] As a consequence of the use of sulphur sensitive catalysts in isomerisation and catalytic reforming, these processes require virtually sulphur free feedstocks. As a result, the gas streams from these units are nearly sulphur free. The gases produced in hydrogen manufacturing plants and from gasification units can also be desulphurised. /cf. 14/

[5] Most other gases produced in the refinery contain hydrogen sulphide (H_2S) and often small quantities of mercaptans.

[6] The flare gas recovery system is in fact a refinery safety device which under normal conditions has no flow /14/.

Liquid fuels used in a refinery originate from various processes (e.g. crude oil distillation, high vacuum distillation, thermal or catalytical cracking). In general, the liquid fuels comprise the following components: atmospheric and vacuum residues, thermally cracked residues, heavy catalytically cracked cycle oil and hydrocracked residues. Sulphur contents of liquid refinery fuels and/or components are given in Table 2. /14/

Table 2: Sulphur contents of liquid refinery fuels (cf. /14/)

Residue	**Sulphur content of residues [wt.-%] from**	
	Crude oil from North Sea	**Crude oil from Middle East**
Atmospheric residue	0.6 - 1.1	2.3 - 4.4
Vacuum residue	1.1 - 1.8	3.6 - 6.1
Cracked residue	n. d.	3.5 - 6.5

n. d. : no data are available

However, lower amounts of sulphur in liquid refinery fuels may occur (e.g. Swedish refineries use fuel oil with a sulphur content of 0.4 - 0.5 wt.-% /cf. 15/.). An average sulphur content of fuel oil used in refineries is given as 2.8 wt.-% in /cf. 2/. A weighted average sulphur content of the mix of refinery gas and heavy fuel oil can be given as 1.7 wt.-% /2/.

The sulphur content of the petroleum coke produced and consumed by refineries depends on the type of crude oil/fractions used. In practice, the sulphur content of coke varies between ca. 0.93 wt.-% sulphur (petroleum coke produced mostly from delayed coking process) and ca. 1.4 wt.-% sulphur (petroleum coke produced mostly from fluid coking process) /cf. 6/.

The formation of nitrogen oxides (NO_x) can be split into “fuel-NO”, “thermal-NO” and “prompt-NO” as discussed in chapter B111 on “Combustion Plants as Point Sources” (Section 3). Within the temperature range under consideration, the formation of “prompt-NO” can be neglected. “Fuel-NO” results from the oxidation of the fuel nitrogen content. For liquid fuels, the content of nitrogen in heavy fuel oil varies between 0.1 and 0.8 wt.-% /7/. The content of nitrogen in gaseous fuels (refinery gas) as well as in solid fuels (petroleum coke contain ca. 0.2 wt.-% /6/) is negligible. Relatively high NO_x emissions may be released by thermal cracking units in petrochemical industry (e.g. at olefin cracking units concentrations of about 130 up to 1,600 mg/m^3 may occur /18/). The design of burner and furnace as well as the operating conditions determine the NO_x formation. NO_x emissions vary considerably for existing and new (optimised) furnaces in refineries (see Table 3).

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[7] For a description of selected units see chapter B411 on "Petroleum Products Processing".

Table 3: Ranges of NO_x concentrations for existing and new (optimised) furnaces in refineries (according to /14/)[1]

Type of process furnace	NO_x concentration [mg/Nm³]	
	Gas[2]	Refinery fuel[3]
Existing furnace	160 - 1,300	280 - 1,000
Furnace with optimal burner and furnace design	100 - 200	about 250[4]

[1] Apart from firing either gas or liquid fuel separately, mixed gas/liquid firing in the same furnace is also practised in refineries, and emission values may differ considerably from the values observed in the case of gas fired units /14/.

[2] The lower range relates to natural gas firing /14/.

[3] Thermally cracked residue /14/; liquid fuel

[4] However, low-NO_x-burners are reported not to be available for low grade liquid fuels. /cf. 14/

Emissions of carbon monoxide (CO), methane (CH_4) and non-methane volatile organic compounds (NMVOC) are mainly associated with poorly regulated combustion processes; they are small when processes are managed correctly.

Heavy metal emissions are mainly determined by the type of fuel used; only liquid and solid fuels are of relevance. Most of the heavy metals (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn, V) are normally released as compounds (e.g. chlorides) in association with particulates (see also chapter B111 on “Combustion Plants as Point Sources”, Section 9). In the case of heavy fuel oil mainly Ni and V are of relevance. Particulate emissions originate from two different sources within a refinery; firstly from process heaters and boilers and secondly from FCC units (CO-boilers), which are not considered here. Their contribution to the total emissions is roughly equal. /cf. 8/.

3.5 Controls

SO_2 emissions from process furnaces are only controlled by the use of low sulphur fuels (e.g. by switching from liquid fuels to gaseous fuels, which contain less sulphur).

For the control of NO_x emissions from process furnaces only primary measures are installed (e.g. low-NO_x-burner, flue gas recirculation). The reduction efficiencies for low-NO_x-burners vary between 10 and 30 %, and for flue gas recirculation between 5 and 15 %. At thermal cracking units in petrochemical industry (e.g. olefine cracking units) also secondary abatement measures may be installed (e.g. SCR, SNCR) /18/.

4/5 SIMPLER AND DETAILED METHODOLOGY

Here both approaches refer to the calculation of emissions based on emission factors and activities, which are jointly discussed in the following. The “simpler methodology” is considered as an overall approach, where activity data refer to production figures. The “detailed methodology” is considered as the recommended approach, where activity data concerning the fuel consumption in refinery process furnaces is available for individual plants. The simpler and the detailed methodologies cover all relevant pollutants.

The annual emission is determined according to Equation (1) by an activity and an emission factor:

$$E_i = EF_i \cdot A \tag{1}$$

E_i	annual emission of pollutant i
EF_i	emission factor of pollutant i
A	activity

The activity A and the emission factor EF_i have to be determined on the same level of aggregation by using available data. The CORINAIR90 methodology requires for refinery process furnaces activity data, which is related to the type of fuel consumed in [GJ/a].

4.1 Simpler methodology

The simpler methodology corresponds to an approach, which takes into account activity rates derived from data of comparable installations or from literature data. Here, it is assumed, that the required activity data (according to CORINAIR90) are not available (see Equation (1)). In practice, statistical material (see also Section 6), which often provides only the throughput of crude oil in [Mg/a], has to be used. Some national statistics publications also provide throughputs per individual refinery.

In order to approximate activity data referring to the energy input into process heaters in [GJ/a] the specific energy consumption has to be taken into account as given e.g. in Equation (2):

$$A_{COR} = F \cdot A_{Stat} \tag{2}$$

A_{COR}	activity in CORINAIR-compatible unit (energy input [GJ])
F	specific energy consumption (energy input/mass crude oil [GJ/Mg])
A_{stat}	activity directly obtained from statistics (mass crude oil [Mg])

For the determination of the specific energy consumption F, related to the throughput of crude oil, only the own consumption of the refinery has to be taken into account. The own consumption of a refinery amounts to about 5 % (average in 1990) of the input (crude oil and intermediate products) /3, 5/. For hydroskimming refineries[8] the fuel demand may vary between 2 and 3 wt.-% and for complex, high conversion refineries between 6 and 8 wt.-% /14/. About 40 % of the refinery fuel consumption is used for process heaters. The fuel split of refinery fuel for its own consumption can be given as: heavy fuel oil (ca. 35 %), petroleum coke (ca. 10 %) and refinery gas (ca. 55 %); the relevance of gas oil is < 1% and can be neglected /3/.

However, the simpler approach leads to significant uncertainties. Therefore, no emission factors are provided for this edition.

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[8] The simplest type of refineries, the so-called „hydro-skimming“ refineries, carry out very little conversion into various products. The product distribution is largely determined by the composition of the crude oil processed and cannot be influenced to a great extent by modifying the operating mode of the refineries. /14/

4.2 Detailed methodology

The detailed methodology corresponds to a plant specific approach, which takes into account as far as possible plant specific information. Here, CORINAIR90 compatible activity data for refinery process furnaces (related to the type of fuel consumed in [GJ/a]) are directly available (Equation (1)).

The following two sections provide individual approaches for the determination of SO_2 and CO_2 emission factors.

4.2.1 SO_2 emission factors

Emission factors for SO_2 in [g/GJ] are given in Table 6 (see Section 8) based on literature data. SO_2 emissions can be directly correlated to the sulphur content of the fuel and the fuel consumption. Emission factors for SO_2 in [g/GJ] can be obtained by using Equation (2):

$$EF_{SO_2} = 2 \cdot C_{S\,fuel} \cdot \frac{1}{H_u} \cdot 10^6 \qquad (2)$$

EF_{SO_2}	emission factor of SO_2 [g/GJ]
$C_{S_{fuel}}$	sulphur content of fuel [wt.-%]
H_u	lower heating value [MJ/kg]

If no data is available, default values are recommended:

- sulphur content of fuel: see Section 3.4,
- lower heating value: see Table 4.

Table 4: Lower heating values of refinery fuels

Fuel used	NAPFUE code	Lower heating value [MJ/kg] /10/
Petroleum coke	110	29.31
Gas oil	204	42.70
Heavy fuel oil	203	41.03
Refinery gas	308	48.36

4.2.2 CO_2 emission factors

Emission factors for CO_2 are given in Table 6 (Section 8) based on literature data. Own estimations can be made according to Equation (3) and by using an approximation for the composition of oil, gas and coke as given in Table 5:

$$EF_{CO_2} = \frac{M_{CO_2}}{M_i} \cdot \frac{1}{H_u} \cdot 10^6 \qquad (3)$$

EF_{CO_2}	emission factor for CO_2 [g/GJ]
M_{CO_2}	molecular weight of CO_2 [g/mol]
M_i	molecular weight of fuel i (see Table 5) [g/mol]
H_u	lower heating value [MJ/kg]

Table 5: Approximations for the molecular weight /3/

Fuel	**Approximation**	**Molecular weight [g/mol]**
Fuel oil	HC	13
Petroleum coke	C	12
Refinery gas	CH_4/C_2H_6	23[1)]

[1)] An assumption concerning the average molecular weight has been made as both fractions are included with a mass portion of 50:50.

4.2.3 Emission factors for other pollutants

Emission factors for the pollutants NO_x, CH_4, NMVOC, CO, and N_2O are given in Table 6 (see Section 8) based on literature data depending on the type of fuel used. Emission factors for heavy metals are given in Table 7 (see Section 8).

6 RELEVANT ACTIVITY STATISTICS

The following statistics can be used for the determination of the throughput of crude oil. The consumption of intermediate products has to be taken into account separately. In some national statistics also the total own consumption of fuels within the refineries is reported.

- Statistical Office of the European Communities (EUROSTAT) (ed.): CRONOS Databank; 1993 (Crude oil production XX 93 0603 3, Crude oil treated in refineries XX 93 0604 3)
- Office for Official Publication of the European Communities (ed.): Annual Statistics 1990; Luxembourg; 1992

Information concerning European refineries is also provided by Concawe (Den Haag).

7 POINT SOURCE CRITERIA

Refineries have to be treated as point sources according to the CORINAIR90 methodology. Process furnaces within a refinery have to be reported collectively as a part of a refinery.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

The following Table 6 contains emission factors for selected pollutants based on literature data.

Table 6: Emission factors of gaseous pollutants for process heaters in refineries[10]

Type of fuel			NAPFUE code	Emission factors						
				SO_2 [g/GJ]	NO_x [g/GJ]	NMVOC [g/GJ]	CH_4 [g/GJ]	CO [g/GJ]	CO_2 [kg/GJ]	N_2O [g/GJ]
s[1]	coke	petroleum	110		300[7]				101[5]	22[7] g/Mg
l[2]	oil	residual	203	245 - 1,962[9]	100 - 210[8] 75 - 328[9]	1 - 41[9]	0.1 - 3.5[9]	7 - 350[9]	78[5] 53 - 79[9]	22[7] g/Mg 2 - 22[9]
g	gas	natural	301	0.7 - 432[9]	1.4 - 140[9]	0.3 - 7[9]	0.3 - 4[9]	1.3 - 280[9]	53 - 55[9]	1.5 - 22[9],
g[3]	gas	liquified petroleum	303	1.7[9]		14[9]	6[9]	45[9]	64[9]	1.5[9]
g	gas	refinery	308	12.5 - 1,423[9]	90[8], 140[7], 155[6] 30 - 150[8] 35 - 756[9]	0.3 - 10[9]	0.3[6] 0.3 - 4[9]	280[6] 10 - 280[9]	60[4], [6] 10 - 57[9]	1.5[6], 0.3 - 22[9], 22[7] g/Mg
l/g	mixture	of oil/gas	-	220[4] g/Mg	350[4] g/Mg					

[1] In CORINAIR90 also NAPFUE codes 103 and 105 have been reported

[2] In CORINAIR90 also NAPFUE code 204 has been reported

[3] In CORINAIR90 also NAPFUE code 303 has been reported

[4] CONCAWE /9/, range for SO_2 emission factors: 70 - 430 g/Mg

[5] BMU, Germany 1993 /12/

[6] BMU, Germany 1994 /16/

[7] CORINAIR /4/

[8] CONCAWE /1/

[9] CORINAIR90 data

[10] At this stage emission factors for thermal cracking units are not available.

Table 7: Heavy metal emission factors for gaseous fuels fired in refinery process heaters /13/

Source	Emission factor [g/TJ]			
	Cr (total)	Cr^{6+} (Hex)[1]	As	Cd
Process heater:				
- Single stage	0.10	0.19	0.03	0.01
- With LNB	0.05	0.01	0	0
- With air preheater	0.05	0	0	0.14
- Reformer	0.09	0.19	0	0

[1] Cr^{6+} is reported separately due to the high toxicity of this species.

For refinery process heaters, which are fed with fuel oil, emission factors for heavy metals are approximately the same as given in Table 31 in chapter B111 on “Combustion Plants as Point Sources”. Residues fuelled in refineries need not be comparable to heavy fuel oils as a product. Therefore, composition data of residues are needed in order to estimate heavy metal emissions /17/.

9 SPECIES PROFILES

Species profiles (oxides of sulphur and nitrogen) are comparable to those released from combustion installations. Details can be found in chapter B111 “Combustion Plants as Point Sources” (Section 9).

10 UNCERTAINTY ESTIMATES

At this stage no information is available.

11 WEAKEST ASPECTS / PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

Weakest aspects discussed here are related to emission factors and activities.

Data provided by CORINAIR90 project can only be used in order to give a range of emission factors. Further work should be invested to develop emission factors which take into account technical specifications and fuel characteristics.

Most refineries process crude oil as well as intermediate products coming from other refineries. The energy demand for the processing of intermediate products differs from the energy demand for the processing of crude oil. The share of intermediate products processing varies strongly. Therefore, further work should be invested in providing characteristic profiles for the energy consumption (own consumption) of a refinery, which are suitable for inventorying purposes.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

13 TEMPORAL DISAGGREGATION CRITERIA

Temporal disaggregation of annual emission data (top-down approach) provides a split into monthly, weekly, daily and/or hourly emission data. Temporal disaggregation of annual emissions released from process furnaces in refineries can be obtained by taking into account the:

- time of operation and
- variation of load.

Data for the annual time of operation in refineries is available from statistics. In principle, refineries produce continuously during the whole year except during standstill time due to maintenance.

The load of the refinery is determined by the variation of production due to the varying demand for petroleum products. Information concerning the variation in the production or the demand for refinery products can only be obtained directly from refinery operators. (Note: the short time demand for refinery products is met by refinery products being stored in tanks.).

14 ADDITIONAL COMMENTS

15 SUPPLEMENTARY DOCUMENTS

16 VERIFICATION PROCEDURES

As outlined in the chapter on “Concepts for Emission Inventory Verification” different verification procedures can be recommended. Verification procedures considered here are principally based on the verification of emission data on a national level and on a plant level. The verification on a plant level relies on comparisons between calculated emissions/emission factors and those derived from emission measurements.

17 REFERENCES

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/9/ Concawe (ed.): Sulphur dioxide emissions from oil refineries and combustion of oil products in western Europe in 1979 and 1982; Den Haag, 1985

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/11/ CORINAIR90 Emission Inventory (Proposals)-working paper for the 19 - 20 September 1991 meeting - Annex 4: Definition of Large Point Sources

/12/ Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (ed.): Umweltpolitik - Klimaschutz in Deutschland, Nationalbericht der Bundesregierung für die Bundesrepublik Deutschland in Vorgriff auf Artikel 12 des Rahmenübereinkommens der Vereinten Nationen über Klimaänderungen; 1993

/13/ Taback, H. J.; Ritter; Karin: Improving emission factors and harp profiles for the petroleum industry; in: Proceedings of the Conference on “Emission Inventory Issues”, US-EPA and AIR Waste Management Association (ed.); Pittsburgh; 1993

/14/ Technical note on the best available technologies to reduce emissions of pollutants into the air from the refining industry; Application of articles 7 & 13 of the Directive 84/360 EEC

/15/ Ms. Froste, Mr. Kvist, Mr. Jansson; personal communcation; February 1995

/16/ Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (ed.): Umweltpolitik - Klimaschutz in Deutschland, Erster Bericht der Regierung der Bundesrepublik Deutschland nach dem Rahmenübereinkommen der Vereinten Nationen über Klimaänderungen; 1994

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/18/ Mr. Drechsler (Umweltbundesamt, Berlin): Personal communication (paper); December 1995

18 BIBLIOGRAPHY

19 RELEASE VERSION, DATE AND SOURCE

Version : 2.0

Date : December 1995

Source : Rentz, Otto; Oertel, Dagmar
Institute for Industrial Production
University of Karlsruhe (TH)
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Abbreviations

FCC	Fluid Catalytic Cracking
g	gaseous state of aggregation
l	liquid state of aggregation
LNB	Low-NO_x-Burner
s	solid state of aggregation
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction

SNAP CODE :

010402
010403
010404
010405
010407

SOURCE ACTIVITY TITLE :

Combustion Plants >= 50 and < 300 MW (boilers)
Combustion Plants < 50 MW (boilers)
Gas Turbines
Stationary Engines
Other (coal gasification, liquefaction,...)

A specific methodology for these activities has not been prepared because the contribution to total national emissions is thought to be currently insignificant, i.e. less than 1% of national emissions of any pollutant.

If you have information contrary to this please contact the expert panel leaders.

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SNAP CODES: **010406**
040201

SOURCE ACTIVITY TITLE: **Coke Oven Furnaces**
Coke Oven (Door Leakage and Extinction)

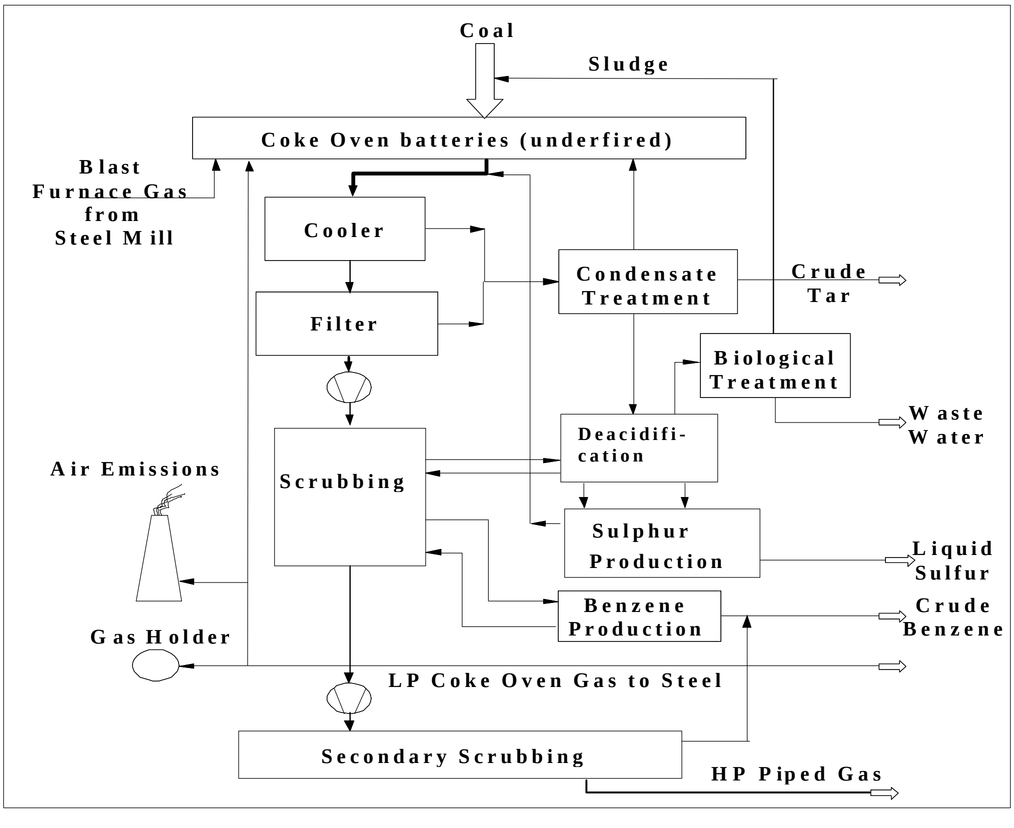
1 ACTIVITIES INCLUDED

Coke-production in general can be divided into the following steps:

Coal handling and storage, coke oven charging, coal coking, extinction of coke, and coke oven gas purification. Combustion in coke oven furnaces (SNAP 010406) is treated in this chapter as well as door leakage and extinction (SNAP 040201).

Figure 1-1 gives a key plan of a coke plant with emission relevant process steps and the by-product recovery section.

Figure 1-1: Key plan of a coke plant (Rentz et al. 1995)



2 CONTRIBUTION TO TOTAL EMISSIONS

Table 2-1: Contribution to total emissions of the CORINAIR90 inventory (*28 countries*)

Source-activity	**SNAP-code**	**Contribution to total emissions [%]**							
		SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3
Coke Oven Furnaces	010406*	0.5	0.3	0	0	0.2	1.0	-	-
Coke Oven (Door Leakage and Extinction)	040201	0.1	0.1	0.2	0.1	0.5	0.1	-	0.1

0 = emissions are reported, but the exact value is below the rounding limit (0.1 per cent)
- = no emissions are reported
* = SNAP90 code 030202

Table 2-2: Contribution to total heavy metal emissions of the OSPARCOM-HELCOM-UNECE inventory for 1990 (up to 38 countries)

Source-activity	**SNAP-code**	**Contribution to total emissions [%]**							
		As	Cd	Cr	Cu	Hg	Ni	Pb	Zn
Coke Oven (Door Leakage and Extinction)	040201	0.3	1.3	1.3	0.2	1.0	0.1	0.1	0.1

The emissions of persistent organics are also relevant. According to this OSPARCOM-HELCOM-UNECE inventory, coke ovens contributed some 3.1 % to total emissions of PAH in 1990.

Coke production is unlikely to be a significant source of sulphurhexafluoride (SF6), hydrofluorocarbons (HFCs) or perfluorocarbons (PFCs), (ETC/AEM-CITEPA-RISOE 1997).

3 GENERAL

About 90 % of the coke consumed in the EU is used in pig iron production. The major part is used in blast furnaces, followed by iron foundries, non-ferrous smelters, and the chemical industry.

3.1 Description

Coke and coke by-products (including coke oven gas) are produced by the pyrolysis (heating in the absence of air) of suitable grades of coal. The process also includes the processing of coke oven gas to remove tar, ammonia (usually recovered as ammonium sulphate), phenol, naphthalene, light oil, and sulphur before being used as a fuel for heating the ovens (World Bank Group 1997).

For coke production, hard coal is crushed, mixed and sieved. The coal is transported to the coke oven, which is charged by the mixture. After heating for 14 to 36 hours at 1,150-1,350°C, in the absence of oxygen, the coked mixture is pressed out of the coke chambers into special wagons. Subsequently, the hot coke will be extinguished.

The emissions related to coke production can be attributed to four sub-processes, namely:

- Coal handling and storage: emitting coal dust,
- Coke production and extinction: emitting coal and coke dust and coke oven gas,
- Coke oven gas handling and purification: emitting benzene, toluene, xylene, phenol, PAH, H_2S, HCN and NH_3,
- Combustion of coke oven gas: emitting C_xH_y, SO_2, NO_x, CO, CO_2, HF and soot.

3.2 Definitions

Production of coke: heating of coal mixtures in absence of oxygen at high temperatures
Extinction of coke: cooling of the hot coke after removal from the coke-chambers
Coke oven gas: the gas formed during coking of the coal

3.3 Techniques

In the coke making process, bituminous coal is fed (usually after processing operations, which control the size and the quality of the feed) into a series of ovens. The coke oven itself is a chamber, built of heat resistant bricks, generally 0.4-0.7 m wide, 4-8 m high and 12-18 m long. A chamber has two doors, one at each end, covering almost the full cross-sectional area. In the roof, there are 3-5 charging holes and a gas outlet ("ascension pipe"). Commonly 40 to 70 chambers, alternating with heating walls, form a coke oven battery (Dutch Notes on BAT 1997). Combustion of gases in burners in the flues between the ovens provides heat for the process. In order to improve the energy efficiency, regenerators are located right under the ovens, exchanging heat from flue gases with combustion air or fuel. Coke oven gas from the by-product recovery plant is the common fuel for underfiring the ovens at most plants, but blast furnace gas, and infrequently, natural gas may also be used (US-EPA 1985).

The ovens are sealed and heated at high temperatures. The generation of steam, gases, and organic compounds starts immediately after charging and they are exhausted via ascension pipes into the crude gas collecting system (Dutch Notes on BAT 1997). Volatile compounds are processed to recover combustible gases and other by-products. After coking, the vertical doors on each end of an oven are removed, a long ram pushes the coke from the oven into a rail quench car, which goes to a quench tower. There, large volumes of water are sprayed onto the coke mass to cool it, so that it will not continue to burn after being exposed to air. Alternatively, circulating an inert gas (nitrogen), also known as dry quenching can cool it. Coke is screened and sent to a blast furnace or for storage.

The raw coke oven gas exits at temperatures of about 760 to 870 °C and is shock cooled by spraying recycled flushing liquor in the gooseneck. This spray cools the gas to 80 to 100 C, precipitates tar, condenses various vapours, and serves as the carrying medium for the condensed compounds. These products are separated from the liquor in a decanter and are subsequently processed to yield tar and tar derivatives (US-EPA 1985b, van Osdell et al. 1979).

The gas is then passed either to a final tar extractor or an electrostatic precipitator for additional tar removal. When the gas leaves the tar extractor, it carries 75 % of the ammonia and 95 % of the light oil originally present when leaving the oven. The ammonia is recovered either as an aqueous solution by water absorption or as ammonium sulphate salt. The gas leaving the saturator at about 60°C is taken to final coolers or condensers, where it is typically cooled with water to approximately 24°C. During this cooling, some naphthalene separates and is carried along with the wastewater and recovered. The remaining gas is passed into a light oil or benzene scrubber, over which is circulated a heavy petroleum fraction called wash oil or a coal-tar oil, which serves as the absorbent medium. The oil is sprayed in the top of the packed absorption tower while the gas flows up through the tower. The wash oil absorbs about 2 to 3 % of its weight of light oil, with a removal efficiency of about 95 % of the light oil vapour in the gas. The rich wash oil is passed to a countercurrent steam stripping column. The steam and light oil vapours pass upward from the still through a heat exchanger to a condenser and water separator. The light oil may be sold as crude or processed to recover benzene, toluene, xylene, and solvent naphtha (US-EPA 1985b, van Osdell et al. 1979).

After tar, ammonia, and light oil removal, the gas undergoes final desulphurisation (e. g. by the Claus process) at some coke plants before being used as fuel. The coke oven gas has a rather high heating value, in the order of 20 kJ/m^3 (STP). Typically, 35 to 40 % of the gas is returned to fuel the coke oven combustion system, and the remainder is used for other plant heating needs (US-EPA 1985b, van Osdell et al. 1979).

Although most benzene is obtained from petroleum, some is recovered through distillation of coke oven light oil at coke by-product plants. Light oil is a clear yellow-brown oil which contains coal gas components with boiling points between 0 and 200°C. [30] Most by-product plants recover light oil, but not all plants refine it. About 13-18 l of light oil can be produced from coke ovens producing 1 Mg of furnace coke. Light oil itself contains from 60 to 85 % benzene (US-EPA 1985, Loibl et al. 1993).

3.4 Emissions

The coke oven is a major source of fugitive emissions into the air. The coking process emits sulphur oxides (SO_x), nitrogen oxides (NO_x), volatile organic compounds (non-methane VOC and methane (CH_4)), carbon dioxide (CO_2), carbon monoxide (CO), ammonia (NH_3), particulate matter, and heavy metals. In general, emissions of nitrous oxide (N_2O) are not relevant. Coke ovens are an important source of PAH emissions (polycyclic aromatic hydrocarbons).

The components of coke oven gas (raw gas) and their concentration can be given as follows.

Table 3.1: Composition of raw coke oven gas (Winnacker 1982)

Components of coke oven gas	Concentration [Vol.-%]
H_2	58 - 65
CH_4	24 - 29
CO	4.6 - 6.8
C_nH_m	2 - 4
CO_2	1.5 - 2.5

Besides these compounds, the following by-products are also components of the coke oven gas produced: tar, phenol, benzene, pyridine, ammonia, H_2S, HCN, CS_2 (carbon bisulphide) (Winnacker 1982). The by-product recovery section of a coking plant (e.g. ammonia processing, tar processing) may release significant amounts of NMVOC, CH_4, NH_3 and particulate matter (covered by SNAP code 040201).

Furthermore, continuous and discontinuous releases of emissions into the air can be distinguished (Dutch Notes on BAT 1997):

Continuous emissions to air:

- Emissions from storage and handling of raw materials and products,
- Oven door and frame seal leakage,
- Ascension pipe leakage,
- Charging holes leakage,
- Coke oven firing,
- Vent systems in gas treatment plant,
- Desulphurisation plant.
-

Discontinuous emissions to air:

- Oven charging,
- Coke pushing,
- Coke cooling.

3.5 Controls

Charging:
Dust particles from coal charging can be evacuated by the use of jumper-pipe system and steam injection into the ascension pipe or controlled by fabric filters (World Bank Group 1997).

Coking:
Emissions decrease with the increase of the size of the ovens. Large ovens increase batch size and reduce the number of chargings and pushings, thereby reducing associated emissions. Emissions are also reduced by constant coking conditions, cleaning, and a low-leakage door construction e. g. with gas sealings (Dutch Notes on BAT 1997).

Pushing:
Emissions from coke pushing can be reduced by maintaining a sufficient coking time thus avoiding the so-called "green push". Fugitive emissions can be controlled by sheds, enclosed

cars or travelling hoods. Captured gases should be treated in fabric filters (World Bank Group 1997).

Quenching:
Dry quenching creates lower emissions compared to wet quenching. Gases released from the dry quenching unit can be extracted and filtered. In the case of wet quenching, measures have to be taken to prevent pollutant transfer from wastewater to the air (Dutch Notes on BAT 1997).

By-product recovery:
In the processing of light oil, tar, naphthalene, phenol, and ammonia vapour recovery systems can be used. Tail gases from desulphurisation (Claus plant) can be returned to the coke oven gas system.

Combustion of coke oven gas:
Flue gases from coke oven firing contain NO_x, SO_2 and particulate matter as main pollutants. SO_2 emissions depend on the degree of desulphurisation of the coke oven gas. NO_x emissions may be reduced by low-NO_x-firing techniques.

4 SIMPLER METHODOLOGY

The most simple approach to assess emissions due to coke production is the use of emission factors related to the mass of coke produced, which cover several sub-processes as described in section 3.1. This procedure does not distinguish combustion emissions and emissions from door leakage and extinction. Therefore, this approach is not in line with the CORINAIR methodology. Nevertheless, it may be applied for pollutants such as SO_2 and NO_x, which mainly arise from fuel combustion.

5 DETAILED METHODOLOGY

The assessment of emissions with the more detailed methodology requires knowledge of the four subprocesses of coke production. It involves the use of emission factors; species profiles for different subprocesses combined with relevant activity statistics. Whenever measurement data are available, they can be used as a basis for the emission estimate.

6 RELEVANT ACTIVITY STATISTICS

Standard statistics on coke production and fuel consumption (e. g. International Energy Agency, United Nations, Eurostat, International Iron and Steel Institute etc.).

7 POINT SOURCE CRITERIA

Integrated iron and steel plants with production capacities of more than 3 million Mg/a have to be treated as point sources according to the CORINAIR90 methodology. Coke oven furnaces included in these integrated iron and steel plants have to be considered as a part of the point source.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

8.1 Simpler methodology

In table 8.1, average overall emission factors are presented for coke production. For reference (Emission Registration 1990), emissions due to coke oven gas purification and fuel combustion are included. In the other references from this table it is not clear if fuel combustion is included or not.

Table 8.1: Overall emission factors for coke production (g/Mg coke produced)

Compound	**Plant type**	**Emission factor**	**Data Quality**	**Abatement type**	**Abatement efficiency**	**Fuel type**	**Country or region**	**Ref.**
Particulates	*All processes*	*500 - 900*	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany*	(Luftreinh. 1989)
Particulates	*All processes*	53	*E*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1990)
Particulates	*All processes*	800 - 5000	*E*	*n. a.*	*n. a.*	*n. a.*	*USA*	*(US-EPA 1990)*
VOC	*All processes*	730 - 2800$^{2)}$	*E*	*n. a.*	*n. a.*	*n. a.*	*Netherlands USA*	(E. Registr. 1990), *(US-EPA 1990)*
PAH	*All processes*	29	*E*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1990)
B(a)P	*All processes*	0.16 - 0.6	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany Netherlands*	(Luftreinh. 1989), (E. Registr. 1990)
Arsenic	*All processes*	0.003 - 0.03, 0.32$^{1)}$	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany, USA*	(Luftreinh. 1989), *(US-EPA 1990)*
Cadmium	*All processes*	0.0007 - 0.8	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany Netherlands*	(Luftreinh. 1989), (E. Registr. 1990)
Chromium	*All processes*	0.17 - 0.34	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany Netherlands*	(Jockel W. 1991), (E. Registr. 1990)
Copper	*All processes*	0.09 - 0.05	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany Netherlands*	(Jockel W. 1991), (E. Registr. 1990)
Mercury	*All processes*	0.004 - 0.04	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany Netherlands*	(Luftreinh. 1989), (E. Registr. 1990)

Table 8.1 (continued): Overall emission factors for coke production (g/Mg coke produced)

Compound	**Plant type**	**Emission factor**	**Data Quality**	**Abatement type**	**Abatement efficiency**	**Fuel type**	**Country or region**	**Ref.**
Nickel	*All processes*	0.065 - 0.19	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany Netherlands*	(Jockel W. 1991), (E. Registr. 1990)
Lead	*All processes*	0.08 - 0.6, 2.85$^{1)}$	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany Netherlands USA*	(Luftreinh. 1989), (E. Registr. 1990), *(US-EPA 1990)*
Zinc	*All processes*	*0.22 - 0.58, 6.49*$^{1)}$	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany Netherlands USA*	(Jockel W. 1991), (E. Registr. 1990), *(US-EPA 1990)*

1) calculated with EPA coke dust profile *(US-EPA 1990)*
2) expressed as methane

8.2 Detailed methodology

According to the detailed methodology emissions should be calculated individually for all sub-processes. Emission factors for the process steps listed below are summarised in table 8.2.

In table 8-3, emission factors are given for the detailed sub-processes for total particulate, NO_x, SO_2, CO, VOC and NH_3 as reported in the USA (US-EPA 1985).

8.2.1 Coal handling

Coal handling consists of transport, pulverising, screening, and blending of several types of coal and storage. Table 8.2 includes factors for emissions of coal dust from the total process of coal handling.

8.2.2 The coking process (without combustion)

Emissions during coking operations are caused by the charging of the coal into the ovens, the oven/door leakage during the coking period, and by pushing the coke out of the ovens. In table 8.2, overall emission factors for these activities are presented for VOC, NMVOC and PAH.

8.2.3 Coke oven gas purification

The coke oven gas collected from the ovens during the coking process is subjected to various operations for separating ammonia, coke oven gas, tar, phenol, benzene, toluene, xylene, pyridine etc. In table 8.2, emission factors are given for the purification process of coke oven gas. The numbers are derived from data of a Dutch coke plant (Emission Registration 1992).

8.2.4 Combustion

Heat, necessary for the coking process, is generated by gas combustion in the flues between the ovens. Coke oven gas is the common fuel for underfiring the ovens at most plants but other gases (blast furnace gas, natural gas) may be used as well. The combustion also causes emissions. In table 8.2, emission factors are given for combustion emissions, related to the thermal energy input.

Table 8.2: Emission factors for sub-processes of coke production

Compound	**Plant type**	**Emission factor**	**Data Quality**	**Abatement type**	**Abatement efficiency**	**NAPFUE code**	**Country or region**	**Ref.**
Coal dust	*Coal handling*	*80 - 2500 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*USA*	*(US-EPA 1985)*
Coal dust	*Coal handling*	*150 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1981)
VOC	*Coking process*	*151 - 590 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1990) (E. Registr. 1992)
VOC	*Coking process*	*2880 g CH_4/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*USA 1967*	*(US-EPA 1985)*
VOC	*Coking process*	*1030 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Germany 1975*	*(Schade 1980)*
CH_4	*Coking process*	*122 - 639 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands, Germany*	(E. Registr. 1992), *(Schade 1980)*
NMVOC	*Coking process*	*29 - 400 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands, USA*	(E. Registr. 1992), *(Breidenbach 1982)*
PAH	*Coking process*	*10 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	*(Duiser et al. 1989)*
VOC	*Gas purification*	*213 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
Benzene	*Gas purification*	*157 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
Toluene	*Gas purification*	*27 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
Xylene	*Gas purification*	*26 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
PAH - 16 EPA	*Gas purification*	*47 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
Phenol	*Gas purification*	*3.2 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
SO_2	*C. oven furnaces*	*0.5 g/GJ*	*C*	*n. a.*	*n. a.*	*301*	*Europe*	*CORINAIR90*

Table 8.2 (continued): Emission factors for sub-processes of coke production

SO_2	C. oven furnaces	14 g/GJ	C	n. a.	n. a.	303	Europe	CORINAIR90
SO_2	C. oven furnaces	500 g/Mg coal; 650 g/Mg coke; 3.3 g/GJ	C	Desulphurisation	n. a.	304	Europe	(CITEPA 1992), CORINAIR90
SO_2	C. oven furnaces	1500 g/Mg coal; 3300 g/Mg coke; 1355 g/GJ	C	No desulphurisation	n. a.	304	Europe	(CITEPA 1992), CORINAIR90
NO_x	C. oven furnaces	100 - 250 g/GJ	C	n. a.	n. a.	301	Europe	CORINAIR90
NO_x	C. oven furnaces	90 g/GJ	C	n. a.	n. a.	303	Europe	CORINAIR90
NO_x	C. oven furnaces	14 - 250 g/GJ	C	n. a.	n. a.	304	Europe	CORINAIR90
NO_x	C. oven furnaces	30 - 178 g/GJ	C	n. a.	n. a.	305	Europe	CORINAIR90
NMVOC	C. oven furnaces	1 - 5 g/GJ	C	n. a.	n. a.	301, 303, 305	Europe	CORINAIR90
NMVOC	C. oven furnaces	1 - 133 g/GJ	C	n. a.	n. a.	304	Europe	CORINAIR90
CH_4	C. oven furnaces	0.02 - 2.5 g/GJ	C	n. a.	n. a.	301, 304	Europe	CORINAIR90
CH_4	C. oven furnaces	3 g/GJ	C	n. a.	n. a.	303	Europe	CORINAIR90
CH_4	C. oven furnaces	0.02 - 0.3 g/GJ	C	n. a.	n. a.	305	Europe	CORINAIR90
CO	C. oven furnaces	1 - 300 g/GJ	C	n. a.	n. a.	301, 305	Europe	CORINAIR90
CO	C. oven furnaces	20 g/GJ	C	n. a.	n. a.	303	Europe	CORINAIR90
CO	C. oven furnaces	2 - 518 g/GJ	C	n. a.	n. a.	304	Europe	CORINAIR90
CO_2	C. oven furnaces	42 - 56 kg/GJ	C	n. a.	n. a.	301, 303, 304	Europe	CORINAIR90
CO_2	C. oven furnaces	105 - 280 kg/GJ	C	n. a.	n. a.	305	Europe	CORINAIR90
N_2O	C. oven furnaces	1.1 - 3 g/GJ	C	n. a.	n. a.	301, 303, 304, 305	Europe	CORINAIR90

Table 8.3: Additional emission factors for the coking sub-processes (kg/Mg coal) (US-EPA 1985)

Type of operation	Particulate EF Rating	Particulate	SO_2	CO	VOC	NO_x	NH_3
Coal crushing							
with cyclone	D	0.055					
Coal preheating							
uncontrolled							
with scrubber	C	1.75					
with wet ESP	C	0.125					
	C	0.006					
Wet coal charging							
Larry car							
uncontrolled							
with sequent charging	E	0.24	0.01	0.3	1.25	0.015	0.01
with scrubber	E	0.008					
		0.007					
Doorleak							
uncontrolled	D	0.27		0.3	0.75	0.005	0.03
Coke pushing							
uncontrolled	B	0.58		0.035	0.1		0.05
with ESP	C	0.225					
with venturi scrubber	D	0.09					
with baghouse	D	0.045					
with mobile scrubber car	C	0.036					
Quenching							
uncontrolled							
dirty water	D	2.62					
clean water	D	0.57					
with baffles							
dirty water	B	0.65					
clean water	B	0.27					
Combustion stack							
uncontr. (COG)	A	0.234	2.0				
uncontr. (BFG)	A	0.085					
with ESP	D	0.046					
with baghouse (COC)	D	0.055					
Coke handling							
with cyclone	D	0.03					
Combined operations	D						

9 SPECIES PROFILES

Table 9-1 presents profiles for VOC emissions of the coking process.

Table 9.1: VOC profiles for the coking process (% weight)

Compound	(Frohne)	(Fudal. 1992)	(VOC 1980)[1]	(Peter 1992)	(Emis. Registr 1992)	(Emis. Registr 1990)	(Emis. Registr 1990)	proposal
CH_4	72	66	45.3	45.4[4]	80.8	62.1	47.4	60
C2-C10 aliphates						17.8	13.6	16
C2	1.0	7.4	8	0.7[2]	4.2			5
C2=	1.1	18.1	27.7		1.0			1-10
C2=-	0.2	0.4	1.2					
C3	0.5	1.6	0.5	1.3[3]				
C3=	0.3	0.6	1.9					
C4	0.8	1.1		2.6				
C4=	0.1	0.4	0.6					
C4==								
C5	1.0			1.3				
C>5	1.0			14.0				
Benzene	7.7	3.4	14.1	11.5	9.7	5.9	4.5	7
Toluene	1.6	0.9	0.7	1.7	1.9	6.7	5.1	1-5
C8 aromatics	0.9			2.9				
C>8 aromatics	0.3			6.6				
Xylene		0.3		2.1	0.6	7.6	5.8	1-5
Styrene					0.3			
Aromatics + benzene							23.7	
Others	11.5			10.0	1.5			
Total	100	100	100	100	100	100	100	

[1] stack sample; probably only fuel combustion; [2] total c2;
[3] total c3; [4] calculated

In table 9.2, profiles of non-methane volatile organic compounds (NMVOC) emissions are given for the coking process.

Table 9.2: NMVOC profiles for the coking process (% weight)

Compound	(Frohne)	(Fudal. 1992)	(VOC 1980)[1]	(Peter 1992)	(Emis. Registr 1992)	(Emis. Registr 1990)	(Emis. Registr 1990)	(Altieri 1945)
C2-C10 aliphates						46.9	25.8	
C2	3.6	21.7	14.5	1.3[2]	22.1			30.3
C2=	3.9	53.0	50.4		5.2			58.0
C2=-	0.7	1.1	2.2					1.2
C3	1.8	4.8	0.9	2.3[3]				1.9
C3=	1.1	1.7	3.5					8.1
C4	2.9	3.4		4.8				0.5
C4=	0.36	1.1	1.1					
C4==								
C5	3.6			2.5				
C>5	3.6			25.6				
Benzene	27.5	9.9	25.6	21.0	50.7	15.5	8.5	
Toluene	5.7	2.5	1.3	3.8	10.0	17.7	9.7	
C8 aromatics	3.2			5.3				
C>8 aromatics	1.1			12.1				
Xylene		0.8		3.8	3.1	20.0	11.0	
Styrene					1.4			
Aromatics + benzene							45.0	
Others	41.1			18.3	7.5			
Total	100	100	100	100	100	100	100	100

[1] stack sample; probably only fuel combustion; [2] total c2; [3] total c3

Table 9.3: Species profiles for polycyclic aromatic hydrocarbons (PAH) expressed as percentage of total PAH

	(Bjorseth et al. 1978) battery personal top sampling (average)		(Eisenhut et al. 1982) oven doors	(Tonkelaar et al. 1983) near coke plant	(Duiser et al. 1989) proposal
total PAH emission factor (g/Mg)	15		2.5	8	10
fluorene	4.4	0.6			2
phenanthrene	19.8	2.6		45.9	30
anthracene	6.2	1.1		7.6	8
fluoranthene	12.8	11.9	1.5	14.3	14
3,6-dimethylphenanthrene				0.8	
benzo(b)fluorene	1.3	4.1		2.1	
pyrene	9.5	8.4	0.9	6.9	9
benzo(a)phenanthrene	0.8	2.8			2
benzo(a)anthracene	3.4	8.5	4.7	3.1	5
chrysene+trifenylene	4.4	11.0	5.9	3.4	4
total low mol PAH	88	62		84	74
benzo(b)fluoranthene	} 1.9	4.7	} 5.7	2.5	} 5
benzo(j)fluoranthene					
benzo(k)fluoranthene			2.1	1.1	
benzo(a)pyrene	2.2	7.7	7.1	2.5	5
benzo(e)pyrene	1.8	4.3	6.2	1.6	4
perylene	0.6	1.8	2.4	0.5	1
indeno(1,2,3,-cd)pyrene	1.5	3.6	6.2	1.8	3
benzo(g,h,i)perylene	1.3	2.9	6.2	4.4	3
anthanthrene	0.9	1.7		0.7	1
coronene	0.7	4.5			2
dibenzo(a,h)anthracene			4.4		} 2
dibenzo(a,j)anthracene				0.3	
dibenzo(a,i)pyrene				0.3	
3-methylcholanthene				0.3	
total high mol. PAH	12	38		16	26

10 UNCERTAINTY ESTIMATES

The quality classification of the emission factors is estimated to be B-C.

11 WEAKEST ASPECTS FOR IMPROVEMENT IN CURRENT METHODOLOGY

Knowledge on abatement techniques, dust removal efficiencies and operating techniques is limited; measurement data on the composition of dust is poor.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

If treated on an area basis, national emission estimates can be disaggregated on the basis of plant capacity, employment or population statistics.

13 TEMPORAL DISAGGREGATION CRITERIA

Coke production can be considered as a continuous process.

14 ADDITIONAL COMMENTS

No additional comments are given

15 SUPPLEMENTARY DOCUMENTS

Environmental Protection Agency
Compilation of Air Pollutant Emission Factors AP 42

PARCOM-ATMOS Emission Factors Manual

16 VERIFICATION PROCESSES

Verification of the emissions can be done by measurements.

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18 BIBLIOGRAPHY

For a detailed bibliography the primary literature mentioned in AP 42 or the PARCOM-ATMOS Manual may be used.

19 RELEASE VERSION, DATE AND SOURCE

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010503
010504
010505

SOURCE ACTIVITY TITLE :

Combustion Plants >= 50 and < 300 MW (boilers)
Combustion Plants < 50 MW (boilers)
Gas Turbines
Stationary Engines

A specific methodology for these activities has not been prepared because the contribution to total national emissions is thought to be currently insignificant, i.e. less than 1% of national emissions of any pollutant.

If you have information contrary to this please contact the expert panel leaders.

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