



Pollution inventory reporting – combustion activities guidance note

Environmental Permitting (England and Wales) Regulations 2010

Regulation 60(1)

Version 4 January 2013

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We operate at the place where environmental change has its greatest impact on people's lives. We reduce the risks to people and properties from flooding; make sure there is enough water for people and wildlife; protect and improve air, land and water quality and apply the environmental standards within which industry can operate.

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We cannot do this alone. We work closely with a wide range of partners including government, business, local authorities, other agencies, civil society groups and the communities we serve.

Published by:

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LIT 7825 / 1213_10

Contents

1. Introduction	4
2. Emissions to air	4
2.1. Relevant pollutants.....	4
2.2. Emission sources	5
2.2.1 Point source emissions	5
2.2.2 Fugitive emissions	5
2.3. Quantification of emissions.....	5
2.3.1. Normalisation.....	5
2.3.2. Solid fuel combustion factors	6
2.3.3. Emission factors for liquid fuel combustion	9
2.3.4. Emission factors for natural gas combustion.....	11
2.3.5. Fuel analysis data.....	13
2.3.6. Estimating fugitive emissions	16
3. Emissions to water	16
3.1 Relevant pollutants.....	16
3.2 Emission sources	17
4. Off-site waste transfers	17
4.1 Introduction	17
4.2 Relevant wastes.....	17
4.3 Transboundary shipments of hazardous waste.....	18
Appendix A: Normalisation of emission concentrations	18
Appendix B: Conversion factors	20
References and other information.....	20

1. Introduction

If we regulate your activity as an A1 installation under the Environmental Permitting (England and Wales) Regulations 2010 (EPR) you will need to submit data to the Pollution Inventory.

You need to report each year. The system opens for reporting on 1 January and the deadline for submitting is 28 February.

Our general guidance sets out how to report and provides information applicable to all businesses and industries.

In this guidance you will find helpful information specific to the combustion sector. The scope includes prescribed/listed combustion activities (for example, combustion appliances with a rated thermal input of 50MWth or more), and combustion activities regulated as a consequence of their association with other listed activities.

If your operations include waste incineration please also read those guidance notes.

You can find additional information on the web:

Pollution Inventory Guidance: www.environment-agency.gov.uk/pi

2. Emissions to air

2.1. Relevant pollutants

The combustion of fossil fuels will almost always lead to releases to air of CO₂, CO, NO_x and particulates. Other pollutants will be released, depending on the fuel and combustion technology used, particularly SO₂. Smaller quantities of pollutants such as trace metals, hydrogen halides, unburnt hydrocarbons, non-methane volatile organic compounds (NMVOCs) and dioxins may also be emitted. These may have a significant influence on the environment owing to their toxicity or their persistence.

Pyrolysis and gasification can be used to pre-treat fuels in order to remove impurities or to produce fuel that can be combusted more readily. Fuels can be either pre-cleaned before combustion or directly combusted. The pollutants emitted from the process are therefore critically dependent on the fuel used and the nature of the process.

Table 2.1 illustrates the likely air pollutants emitted from different types of fuel. Use the table as a **guide** only and you should verify that there are no other pollutants emitted from your process.

Separate PI guidance exists for landfill operations, including the use of GasSim, a computer model that calculates emissions from landfill gas combustion.

Subsidiary or substitute fuels may contain other pollutants that will require reporting.

Table 2.1 Main pollutants likely to be emitted to air

Fuel type	Inputs	Potential air emissions
Solid	Coal	NO _x , CO, CO ₂ , SO _x , particulate matter (including PM ₁₀), fugitive dust, trace metals, PCBs and PAHs, hydrogen halides, methane, NMVOCs, dioxins, N ₂ O.
	Biomass	NO _x , CO, CO ₂ , SO _x (low), particulate matter (including PM ₁₀), CH ₄ , NMVOCs, trace metals (from sewage sludge).
Liquid	Fuel oil	NO _x , CO, CO ₂ , SO _x , particulate matter (including PM ₁₀), PCBs and PAHs, hydrogen chloride, trace metals, and dioxins.
Gaseous	Natural gas	NO _x , CO, CO ₂ , CH ₄ .
Secondary fuels	Solid, liquid or gaseous	NO _x , CO, CO ₂ , SO _x , particulate matter (including PM ₁₀), PCBs and PAHs, hydrogen halides, trace metals, NMVOCs, H ₂ S, ammonia and dioxins.

2.2. Emission sources

2.2.1 Point source emissions

These emissions are exhausted via a stack or vent, that is, a single point source, into the atmosphere. Abatement equipment, for instance an electrostatic precipitator (ESP) or fabric filter (bag house), can be incorporated into the exhaust system prior to discharge to atmosphere. Point source emissions will be the most significant emission source for combustion activities.

2.2.2 Fugitive emissions

Fugitive emissions are those that are not released from a point source such as a stack. They include dust from coal and ash stockpiles and entrainment of pollutants during material handling. Leaks from valves and flanges are also examples of fugitive emissions. With appropriate management and control, these emission sources are generally minor for the combustion sector. You only need to report fugitive emissions that leave the site to the PI. You don't need to report contained spills, but do need to report vapour emissions that may have dispersed.

2.3. Quantification of emissions

2.3.1. Normalisation

Take care to ensure that the emission concentration and flow rate are compatible. For instance normalised emission concentrations should be multiplied by normalised volumetric flow rates or actual, measured emission concentrations multiplied by actual, measured volumetric flow rates. Normalised emission rates are quoted in terms of a standard oxygen concentration, and are usually dry gas, at a temperature of 273K and a pressure of 101.3 kPa. It is always good practice to confirm the basis of

measured data. See Appendix A for formulae to convert between normalised and actual emission concentrations.

2.3.2. Solid fuel combustion factors

(i) Electricity supply industry (ESI)

The emission factors contained in this section represent currently agreed factors for electricity generating stations. They have been developed from measurements on large electricity generating stations (greater than 300 MW_{th}) and are regularly updated. Further detail on these emission factors is contained in the ESI methodology³.

Table 2.2 includes estimates of the amount of 'as received' coal that would need to be burnt in a year in order to exceed the reporting thresholds. A value for the tonnes of coal that will need to be burnt for SO₃ has not been provided, as you will report it with SO₂ (which is either normally estimated from CEMS or fuel analyses in accordance with Section 2.3.5). ESI plant burning less than the indicated tonnage of coal should report emissions as **brt** for that particular pollutant provided that there are no other sources of the pollutant on site.

Emissions of NO_x from ESI coal fired power plants that do not use CEMS for annual mass emissions can be calculated from the fuel burn and NO_x factors which have been agreed with us on a station specific basis.

Particulate matter concentrations are normally measured by CEMS for ESI plant. The annual mass emission should be calculated from the instantaneous measured concentration multiplied by the instantaneous volumetric emission. Where load and abatement performance is constant, the average concentration and flow rate can be used. For ESI plant it is generally assumed that each tonne of coal generates 9,000 m³ of flue gas normalised at 6% oxygen concentration.

The PI return requires the total, PM₁₀ and PM_{2.5} fractions of the particulate matter to be reported. For ESI coal fired plant, the PM₁₀ and PM_{2.5} fractions are assumed to be 80% and 40% respectively of the total particulate matter emitted. You can also use these factors when burning peat or biomass.

Emissions of hydrogen chloride, 'chlorine and inorganic compounds – as HCl' and 'fluorine and inorganic compounds – as HF' are normally estimated from fuel analysis, as shown in section 2.3.5.

Table 2.2 UK ESI PI emission factors for large combustion plant

Species	Emission factor (kg/tonne 'as received' coal burnt) for pulverised coal plant with or without FGD	[te coal burnt for above reporting threshold]
Dioxins and furans (expressed as I-TEQ)	1.5×10^{-11}	[666,667]
Dioxins and furans (expressed as WHO – TEQ)	1.6×10^{-11}	[625,000]
PCB (expressed as WHO –TEQ)	1.8×10^{-10}	[55,556]
PCB (expressed as total mass)	9.9×10^{-8}	[1,010,101]
Benzo(a)pyrene (BaP)	9.0×10^{-7}	[1,111,111]
Anthracene	2.7×10^{-7}	[brt]*
Benzo(b)fluoranthene	5.4×10^{-7}	[1,851,852]
Benzo(g,h,i)perylene	5.4×10^{-7}	[1,851,852]
Benzo(k)fluoranthene	5.4×10^{-7}	[1,851,852]
Chrysene	3.6×10^{-7}	[brt]*
Fluoranthene	4.5×10^{-7}	[2,222,222]
Indeno(1,2,3-cd)pyrene	5.4×10^{-7}	[1,851,852]
Naphthalene	4.9×10^{-5}	[2,040,816]
Methane	1.4×10^{-2}	[714,286]
Non-methane volatile organic compounds	2.7×10^{-2}	[370,370]
Carbon monoxide	1.1	[90,909]
SO ₃ (reported as part of Sulphur oxides - SO ₂ and SO ₃ as SO ₂)	6.3×10^{-2}	-
Nitrous oxide	2.6×10^{-2}	[384,615]

Note: * You should always report these emissions as below the reporting threshold given the required fuel burn.

(ii) Generic factors

In the absence of other information, you can use generic emission factors based on currently achievable emission rates from various combustion plant. The generic emission factors in this section have been taken from existing UK regulatory guidance for combustion appliances^{9,10,11,12} supplemented with Local Authority guidance^{13, 14}.

The existing UK regulatory guidance contains achievable emission data post abatement in terms of mg/MJ of net thermal input together with the equivalent normalised emission concentrations (mg/m³). If you know the normalised emission concentration of your combustion appliance, you can calculate the equivalent emission factor in terms of mg/MJ and use equation 1 below. The relevant mg/MJ and mg/m³ values from the guidance are listed in table 2.3, table 2.5 and table 2.7 for each fuel category. The generic emission factors (EF_i) for coal firing are presented in table 2.3 below and are expressed in terms of the **net** heat input into the combustion appliance.

$$(1) E = A_e \times EF \times 10^{-6}$$

Where: E = emission of pollutant, kg/yr
A_e = annual energy consumption, MJ/yr
EF = energy emission factor of pollutant, mg/MJ

The emission factors also enable an estimate to be made of the size of combustion plant that would need to be operated for the emission to be above the reporting threshold values. These estimates are also included in table 2.3 in terms of the average MW_{th} net thermal input of the plant, assuming that the combustion appliance operates for 100% of the year. If the combustion plant operates for less than 100% of the year, the calculated MW_{th} threshold can simply be divided by the percentage operating time to provide the appropriate MW_{th} threshold. For single combustion appliances that are rated less than the indicated MW_{th} threshold, you can make a **brt** return. If you have more than one combustion appliance on site, your aggregate emission may be above the threshold value.

Table 2.3 Solid fuel firing generic emission factors (net basis)

Technology	Emission factor	Particulate matter		NO _x		CO	
		mg/MJ	mg/m ³	mg/MJ	mg/m ³	mg/MJ	mg/m ³
Stoker boiler, in-furnace desulphurisation ¹¹	EF	9	25	105	300	50	150
	Threshold for <i>brt</i> (MW_{th})	35		30		63	
CFBC in-bed desulphurisation ¹¹	EF	9	25	70	200	50	150
	Threshold for <i>brt</i> (MW_{th})	35		45		63	
PFBC, in-bed desulphurisation and SNCR ¹¹	EF	9	25	21	60	10	30
	Threshold for <i>brt</i> (MW_{th})	35		151		315	
PF boiler, dry lime injection, low NO _x burners ¹²	EF	9	25	225	650	35	100
	Threshold for <i>brt</i> (MW_{th})	35		14		91	
PF boiler, wet limestone scrubbing, low NO _x burners and reburn ¹⁰	EF	5	15	87	250	35	100
	Threshold for <i>brt</i> (MW_{th})	63		36		91	
PF boiler, wet limestone scrubbing, low NO _x burners and SCR ¹⁰	EF	5	15	70	200	35	100
	Threshold for <i>brt</i> (MW_{th})	63		45		91	
Boiler, 20-50 MW_{th} , stoker firing ¹⁴	EF	108	300	160	450	50	150
	Threshold for <i>brt</i> (MW_{th})	2		20		63	
Boiler, 20-50 MW_{th} , other firing ¹⁴	EF	108	300	225	650	50	150
	Threshold for <i>brt</i> (MW_{th})	2		14		63	

For coal fired plants incorporating Selective Catalytic Reduction (SCR), you can use an emission factor of 4 mg/MJ (10 mg/m³) for ammonia.

Plant employing Selective Non-Catalytic Reduction (SNCR) could also release ammonia and nitrous oxide. In the absence of other information, emission factors for SNCR for ammonia and nitrous oxide releases can be assumed to be 2 mg/MJ (5 mg/m³) and 21 mg/MJ (60 mg/m³) respectively.

For unabated emissions of coal, peat or biomass powered plant the PM₁₀ fraction can be assumed to be 40% of the total particulate matter emitted, rising to 80% for plant with ESPs or bag filters and dry FGD and 95% for plant with ESPs or bag filters and wet FGD.

2.3.3. Emission factors for liquid fuel combustion

(i) Electricity Supply Industry (ESI)

Like section 2.3.2, the UK ESI emission factors are listed in table 2.4 for heavy fuel oil fired plant. Further detail on these emission factors is contained in the ESI methodology⁴.

Table 2.4 also includes estimates of the amount of oil that would need to be burnt to exceed the reporting thresholds given the listed emission factors. A value for the tonnes of oil that will need to be burnt for SO₃ has not been provided, as it will be reported with SO₂. For ESI plant burning less than the indicated tonnage of oil you should report emissions as **brt** for that particular pollutant provided that there are no other sources of the pollutant on site.

Table 2.4 UK ESI PI emission factors for large combustion plant

Species	Emission factor (kg/tonne oil burnt) for heavy oil fired plant	[te oil burnt for above the reporting threshold]
Dioxins and furans (expressed as I-TEQ)	2.1×10^{-11}	[497,512]
Dioxins and furans (expressed as WHO – TEQ)	2.1×10^{-11}	[497,512]
PCB (expressed as WHO – TEQ)	2.4×10^{-10}	[41,667]
PCB (expressed as total mass)	1.3×10^{-7}	[769,231]
Benzo(a)pyrene (BaP)	1.2×10^{-6}	[833,333]
Anthracene	3.6×10^{-7}	[brt]***
Benzo(b)fluoranthene	7.2×10^{-7}	[1,388,889]
Benzo(g,h,i)perylene	7.2×10^{-7}	[1,388,889]
Benzo(k)fluoranthene	7.2×10^{-7}	[1,388,889]
Chrysene	4.8×10^{-7}	[brt]***
Fluoranthene	6.0×10^{-7}	[1,666,667]
Indeno(1,2,3-cd)pyrene	7.2×10^{-7}	[1,388,889]
Naphthalene	6.5×10^{-5}	[1,538,462]
Methane	1.8×10^{-2}	[555,556]
Non-methane volatile organic compounds	3.6×10^{-2}	[277,778]
Carbon monoxide	1.5	[6,667]
SO3 (reported as part of Sulphur oxides - SO2 and SO3 as SO2)	4.2×10^{-2} * 1.08**	[-] [-]
Nitrous oxide	3.5×10^{-2}	[285,714]

Note

- * for plant with Mg(OH)₂ flue gas conditioning
- ** for plant without Mg(OH)₂ flue gas conditioning
- *** always report these emissions should as below the reporting threshold

Emissions of NO_x from ESI oil fired power plants that do not use CEMS for determining annual mass emission can be calculated from the fuel burn and NO_x factors that have been agreed with us on a station specific basis.

Particulate matter concentrations are normally measured by CEMS for ESI plant. The annual mass emission should be calculated from the instantaneous measured concentration multiplied by the instantaneous volumetric emission, as in equation 1. Where load is constant, the average concentration and flow rate can be used. For ESI plant it is generally assumed that each tonne of oil generates 12,000m³ of waste gas normalised at 3% oxygen concentration.

You need to report the total, PM₁₀ and PM_{2.5} fractions of the particulate matter to the PI. For ESI oil fired plant, the PM₁₀ and PM_{2.5} fractions are assumed to be 71% and 52% respectively of the total particulate matter emitted.

(ii) Generic factors

As for section 2.3.2, and based on the same referenced information sources, emission factors based on achievable emission rates from various liquid fired combustion plant can be used in equation 1. Relevant emission factors for liquid fired plant are given in table 2.5 (in terms of net heat input), and the same methodology should be used as that outlined in the general guidance.

Table 2.5 Liquid fuel firing generic emission factors (net basis)

Technology	Emission factor	Particulate matter		NO _x		CO	
		mg/MJ	mg/m ³	mg/MJ	mg/m ³	mg/MJ	mg/m ³
Gas turbine (after 1994) ¹³	EF	0	0	105	125	50	60
	Threshold for <i>brt</i> (MW _{th})	-		30		63	
Gas turbine (pre-1994) ¹³	EF	0	0	140	165	84	100
	Threshold for <i>brt</i> (MW _{th})	-		23		38	
Boilers, 20-50MW, L/M/H fuel oil firing ¹⁴	EF	42	150	125	450	42	150
	Threshold for <i>brt</i> (MW _{th})	8		25		75	
Boilers, 20-50MW, distillate firing ¹⁴	EF	28	100	55	200	42	150
	Threshold for <i>brt</i> (MW _{th})	12		58		75	
Compression ignition engine, SCR ¹²	EF	40	50	125	150	125	150
	Threshold for <i>brt</i> (MW _{th})	8		25		25	

For liquid fuel fired plants incorporating SCR, an emission factor of 3 mg/MJ (10 mg/m³) for ammonia can be used.

For unabated emissions, the PM₁₀ fraction can be assumed to be 45% of the total particulate matter emitted, rising to 80% for plant with ESPs or bag filters and dry FGD and 90% for plant with ESPs or bag filters and wet FGD.

2.3.4. Emission factors for natural gas combustion

(i) Electricity Supply Industry (ESI)

Like section 2.3.2, the UK ESI emission factors are listed in table 2.6 for natural gas fired plant. Further detail on these emission factors is contained in the ESI methodology³. Sulphur dioxide emissions are derived from Graham¹⁵. Note that the emission factors are based on gross calorific values (GCV).

Also included in table 2.6 are the approximate GJ of energy that would be required to exceed the reporting thresholds given the listed emission factors and burning only natural gas.

Table 2.6 UK ESI PI emission factors for large combustion plant

Species	Emission factor (g/GJ gas burnt) for gas firing (based on GCV)	[GJ of energy giving rise to numerical reported value]
Dioxins and furans (expressed as I-TEQ)	0	[-]
Dioxins and furans (expressed as WHO – TEQ)	0	[-]
PCB (expressed as WHO –TEQ)	0	[-]
Benzo(a)pyrene (BaP)	0	[-]
Anthracene	0	[-]
Benzo(b)fluoranthene	0	[-]
Benzo(g,h,i)perylene	0	[-]
Benzo(k)fluoranthene	0	[-]
Chrysene	0	[-]
Fluoranthene	0	[-]
Indeno(1,2,3-cd)pyrene	0	[-]
Naphthalene	0	[-]
Methane	3.7	[2,702,700]
Non-methane volatile organic compounds	0.9	[11,111,000]
Carbon monoxide	13	[7,692,300]
Nitrous oxide	0.5	[20,000,000]

NO_x emissions from CCGT and gas-fired plant are generally calculated from continuous monitors.

For the combustion of natural gas, the ESI PI methodology advises a revised emission factor of 0.80 g/GJ (GCV) or 0.89 g/GJ (NCV) for particulates from gas turbine plant.

For gas turbines running on distillate fuel, for example during start-up, the emission factors given in table 2.5 can be used, and 100% of the particulate matter emission assumed to be PM_{2.5}.

(ii) Generic factors

Like section 2.3.2, and based on the same referenced information sources, emission factors based on achievable emission rates from various natural gas fired combustion plant can be used in equation 1. Relevant emission factors for natural gas fired plant are given in table 2.7 (in terms of net heat input), and you should use the same methodology as that outlined in the general guidance. Note that the emission factors are based on net calorific values (NCV).

Table 2.7 Natural gas fuel firing generic emission factors (net basis)

Technology	Emission factor	Particulate matter		NO _x		CO	
		mg/MJ	mg/m ³	mg/MJ	mg/m ³	mg/MJ	mg/m ³
Gas turbine, after 1994 ¹³	Efi (mg/MJ)	0	0	50	60	50	60
	Threshold for <i>brt</i> (MW _{th})	-		63		63	
Gas turbine, pre- 1994 ¹³	Efi (mg/MJ)	0	0	105	125	84	100
	Threshold for <i>brt</i> (MW _{th})	-		30		38	
Boilers, 20-50MW, Flue Gas Recirculation (FGR) ¹⁴	Efi (mg/MJ)	1	5	39	140	30	100
	Threshold for <i>brt</i> (MW _{th})	317		81		106	
Dual Fuel Compression Ignition Engine, Selective Catalytic Reduction (SCR) ¹⁰	Efi (mg/MJ)	15	20	85	100	375	450
	Threshold for <i>brt</i> (MW _{th})	21		37		9	
Dual Fuel Compression Ignition Engine, lean burn ¹⁰	Efi (mg/MJ)	15	20	125	150	125	150
	Threshold for <i>brt</i> (MW _{th})	21		25		25	
Spark Ignition Engine, SCR ¹⁰	Efi (mg/MJ)	0	0	85	100	125	150
	Threshold for <i>brt</i> (MW _{th})	-		37		25	
Spark Ignition Engine, lean burn, Exhaust Gas Recirculation (EGR) ¹⁰	Efi (mg/MJ)	0	0	125	150	125	150
	Threshold for <i>brt</i> (MW _{th})	-		25		25	

For both compression ignition engines and spark ignition engines, you can use a factor of 170 mg/MJ (200 mg/m³) for NMVOCs. For natural gas fired plants incorporating SCR, you can use an emission factor of 8 mg/MJ (10 mg/m³) for ammonia.

Apart from mercury, trace metallic elements in natural gas are assumed to be zero. For mercury, an emission factor of 1 x 10⁻⁴ mg/m³ of gas burnt can be used to calculate mercury vapour emissions. In this case, greater than 1 x 10¹⁰ m³ of gas would need to be burnt in a year to exceed the reporting threshold.

The PM₁₀ and PM_{2.5} fractions can be assumed to be 100% of the total particulate matter emitted when burning natural gas.

2.3.5. Fuel analysis data

(i) General

The use of fuel analysis data to determine emissions is similar to the use of emission factors. The basic equation used in fuel analysis emission calculations is:

$$(2) E = Q_f \times [\text{Op hours}] \times [\text{PC}_f/100] \times (\text{MM}_p / \text{EM}_f)$$

Where:

- E = emission of pollutant, kg/yr
- Q_f = fuel use (kg/hr)
- PC_f = pollutant concentration in the fuel (%)
- Op hours = operating hours per year, hr/yr
- MM_p = molar mass of pollutant as emitted after combustion

EM_f = relative atomic mass of polluting element as present in fuel

Equation 2 is the method usually used for calculating SO_2 emissions where it is normally assumed that all of the sulphur in the fuel is converted to SO_2 . However, when using the equation for coal fired plant, it is assumed that 5% of the sulphur is retained in the ash.

Where the pollutant concentration in the fuel is consistent over the averaging period (one year), equation 2 can be written as:

$$(3) E = M \times [PC_f/100] \times (MM_p / E_f)$$

Where:

E	=	emission rate of pollutant in kg/yr
M	=	mass of fuel burnt in one year (kg/yr)
PC_f	=	pollutant concentration in the fuel (%)
MM_p	=	molar mass of pollutant as emitted after combustion
EM_f	=	relative atomic mass of pollutant as present in fuel

Example: This example shows how SO_2 emissions can be calculated from oil combustion, based on fuel analysis results and fuel flow information. It is assumed that the facility operates using oil for 150 hours per year and that abatement of SO_2 does not occur.

Q_f	=	2000 kg/hr
PC_f	=	1.17%
MW_p	=	64
EW_f	=	32
Op hours	=	150 hr/yr
E	=	$Q_f \times PC_f \times (MW_p / EW_f) \times [Op \text{ hours}]$
	=	$[(2000) \times (1.17 / 100) \times (64/32) \times 150] \text{ kg/yr}$
	=	$7.02 \times 10^3 \text{ kg/year (7.02 tonnes/year)}$

Equation 2 can also be used for volatile elements such as fluorine and chlorine as well as trace metallic pollutants, although some of these species are retained in the plant, either in the ash or in abatement equipment (see below).

When using equation 2 or equation 3, be aware that the amounts of pollutants present in the fuel can vary significantly. For UK ESI plant, the trace element concentration in the coal is calculated as a yearly weighted mean average for each plant, based on the delivered tonnage of coal. Where coals have not been analysed for trace element content, then you should use an average value for coals from a similar geographic region.

(ii) Solid fuel analysis

For elements that are captured effectively in either bottom ash or fly ash, equation 2 can result in the overestimation of emissions. In addition, emission quantities of volatile and semi-volatile components will greatly depend on the emission temperature and abatement collection efficiency as volatile and semi-volatile substances can condense on fine particulate matter. Increasing the emission temperature may significantly increase the pollutant release rate of volatile components. You need to take into account any changes to the process conditions that may affect pollutant partitioning or capture in emission calculations by the determination of site- specific retention and enrichment factors (see below).

Mass emissions of trace metallic elements from coal combustion can be calculated indirectly from the amount of particulate matter emitted, corrected by factors representing the concentration of the trace element in the coal and how much of the element is chemically present in the ash, using the following equations. The total emission is the sum of the emission from the non-volatile and volatile phases:

Non-volatile phase:

$$(4) E_{nv} = PC_{coal} \times (100 / AA) \times F \times R \times PM$$

Volatile phase:

$$(5) E_v = PC_{coal} \times (1 - F) \times CB$$

Where:	E_{nv}	= Non-volatile pollutant emission (kg/yr)
	E_v	= Volatile pollutant emission (kg/yr)
	PC_{coal}	= Trace element weight fraction in the coal
	AA	= Average ash mass percentage in coal (%)
	F	= Retention factor in ash (-)
	R	= Enrichment factor (-)
	PM	= Particulate matter emission (kg/yr)
	CB	= Coal burned (kg/yr)

Common enrichment and retention factors that are used across UK coal fired ESI plant are tabulated in table 2.8. These factors are appropriate for exhaust gas temperatures of less than approximately 130°C. For higher exhaust gas temperatures the factors may differ, especially for the more volatile elements, so you should use site-specific factors.

The use of Flue Gas Desulphurisation (FGD) will lead to the retention of sulphur from the emission, but it will also lead to the retention of soluble acid halides such as HCl and HF. In the absence of site specific data for FGD, retention factors for HCl and HF should be taken as 98% and 72% respectively. The additional factors given in table 2.8 for FGD are for wet limestone/gypsum systems.

Table 2.8 UK ESI PI coal combustion factors

Element	Retention factor (F)	Enrichment factor (R)	FGD retention factor (vapour)
Arsenic	1	3.4	-
Selenium	0.8	9.0	0.65
Lead	1	2.9	-
Nickel	1	1.9	-
Chromium (total)	1	1.7	-
Copper	1	2.0	-
Zinc	1	4	-
Cadmium	1	4.5	-
Mercury	0.5	4.0	0.5

To use equations 4 and 5, you need to know the percentage of trace metallic elements present in the coal. As coal composition can vary significantly depending on the source of the fuel, you should obtain information on the trace elements from the supplier, or have specific coal analysis carried out.

Fuel composition should also be taken into account in determining pollutant emissions from subsidiary or substitute fuels. In the absence of other data, for fuels such as biomass that have a low ash content, the enrichment and retention factors given above can be used.

(iii) Liquid fuel analysis

You can use equation 5 to calculate trace metallic emissions from oil-fired plant. As a generality within the ESI methodology it is assumed that for large, heavy fuel oil plant with particulate or grit arrestors a retention factor of 0.75 can be used for trace elements. Appropriate retention factors should be determined for other abatement plant. In the absence of abatement, the retention factor would be zero.

As with coal, information on the composition of the trace elements in the fuel should be obtained from the supplier or be measured.

Emissions of halogens from oil-fired plant can be assumed to be zero.

(iv) Natural gas analysis

As indicated in Section 2.3.2, apart from mercury, natural gas supplies in the UK are currently assumed to have zero trace metal content. Emissions of halogens from natural gas fired plant are also assumed to be zero.

Where no specific gas analysis is available, and in order to calculate emissions from gas venting, natural gas should be assumed to comprise 1% CO₂, 1% nitrogen, 92% CH₄ and 6% NMVOCs².

2.3.6. Estimating fugitive emissions

For solid fuel plant, particulate matter emissions can occur by dust blow from coal stocks and ash storage areas. However, these can be assumed to be low in comparison to stack emissions unless specific events have occurred which are known to have released significant quantities of material off-site.

Techniques for estimating fugitive emissions from the surface of stockpiles are limited. Options include measuring ambient dust levels upwind and downwind of the source of interest and/or applying predictive mathematical models.

Methane and other hydrocarbon emissions from coal stocks and oil tank filling can be assumed to be small in relation to emissions through the stacks. For natural gas fired plant, where gas is vented to atmosphere for operational and maintenance purposes, the mass emissions of CO₂, CH₄ and NMVOCs should be calculated from the gas composition.

3. Emissions to water

Emissions of substances to water can be either direct to controlled waters or indirect, following transfer to off-site effluent treatment plant. Guidance on what constitutes an emission or a transfer is contained in the general PI guidance document.

We recognise that you may experience difficulty disaggregating EPR and non-EPR releases of substances to water where both pass through a common monitoring point as a combined effluent. In cases where it is not possible to estimate the individual contributions, the combined effluent value should be used.

3.1 Relevant pollutants

You need to consider a variety of substances when reporting emissions to water or transfers in wastewater. The main ones are illustrated in table 3.1. Use the table as a **guide** only, and verify that there are no other pollutants emitted from the process. The significance of each parameter depends on the specific plant configuration and the process applied, which also determines the type and amount of pollutant present in the wastewater prior to treatment.

Table 3.1 Guide on main reportable substances likely to be emitted to water

Substance	Substance
Arsenic	Zinc
Cadmium	Iron
Chromium	
Copper	Nitrogen (total as N)
Lead	Phosphorus (total as P)
Mercury	Chlorides
Nickel	Fluorides

3.2 Emission sources

Emissions to water generally arise from the following sources:

- cooling water system
- demineralised water treatment plant
- boiler blowdown
- FGD wastewater treatment plant
- ash transport wastewater
- surface water run-off from storage areas (for example, fuel, ash, FGD material)
- cleaning water

You need to consider **all** emission sources to water and characterise the flows and emission concentrations from each source.

4. Off-site waste transfers

4.1 Introduction

Wastes must be classified by the List of Wastes Regulations (LOW) 6-digit codes and by the relevant Waste Framework Directive disposal or recovery codes (D&R).

There is no reporting threshold for hazardous wastes, which are indicated by an asterisk in the LOW. For all other LOW/D&R code combinations, a reporting threshold of 5 tonnes applies.

Any transfer of waste off-site to a third party is covered by the Duty of Care provisions of the Environmental Protection Act 1990. This includes the requirement to describe the waste and record the quantity. You should therefore use data generated in compliance with Duty of Care requirements to complete the PI return.

4.2 Relevant wastes

Typical wastes that may be generated in this sector are:

- bottom ash and/or boiler slag
- fly-ash

- fluidised bed ash
- flue gas desulphurisation residues
- special wastes (for instance solvents)
- metallic wastes
- chemical wastes
- waste oils
- general waste

You do not have to report materials that are recognised as by-products rather than wastes, such as sold gypsum, under the off-site waste transfer section.

4.3 Transboundary shipments of hazardous waste

The annual quantities of any transboundary hazardous waste shipments taking place must be reported to the PI.

Appendix A: Normalisation of emission concentrations

In many cases, pollutant emission concentrations to air are reported as normalised concentrations, the actual measured emission concentration having been adjusted to a normalised temperature (273K), oxygen, pressure and/or water vapour concentration. In calculating mass emissions to air, it is important that either the actual release concentration is multiplied by the actual volumetric flowrate, or the normalised concentration is multiplied by the normalised volumetric flow rate

The following equations can be used to correct measured concentrations and flow rates for temperature, oxygen, pressure and water vapour content.

Concentrations

To correct for moisture concentration to dry (0% oxygen)

$$C_d = C_m \times (100/(100 - \%H_2O))$$

Where: C_d is the dry concentration

C_m is the measured concentration
 $\%H_2O$ is the measured water vapour percentage

To correct the % oxygen to dry basis (if required – may already be measured dry)

$$O_2(\text{dry}) = O_{2m} \times (100/(100 - \%H_2O))$$

Where: $O_2(\text{dry})$ is the dry oxygen percentage
 O_{2m} is the measured oxygen percentage

To correct to normalised oxygen concentration

$$C_{\text{corr}} = C_d \times (20.9 - O_{2\text{norm}})/(20.9 - O_2(\text{dry}))$$

Where: C_{corr} is the corrected concentration for oxygen concentration
 $O_{2\text{norm}}$ is the stated normalised oxygen percentage

To correct for temperature

$$C_{\text{normT}} = C_{\text{corr}} \times ((273 + T_m)/273)$$

Where: C_{normT} is the normalised concentration for temperature
 T_m is the measured temperature in degrees centigrade

To correct for pressure

$$C_{norm} = C_{normT} \times (101.3/P_m)$$

Where: C_{norm} is the normalised concentration
 P_m is the measured pressure in kPa

Volumetric flowrates

To correct for moisture concentration to dry (0% oxygen)

$$Q_d = Q_m \times ((100 - \%H_2O)/100)$$

Where: Q_d is the dry volumetric flowrate
 Q_m is the measured volumetric flowrate
 $\%H_2O$ is the measured water vapour percentage

To correct the % oxygen to dry basis (if required – may already be measured dry)

$$O_2(\text{dry}) = O_{2m} \times (100/(100 - \%H_2O))$$

Where: $O_2(\text{dry})$ is the dry oxygen percentage
 O_{2m} is the measured oxygen percentage

To correct to normalised oxygen concentration

$$Q_{corr} = Q_d \times (20.9 - O_2(\text{dry})) / (20.9 - O_{2norm})$$

Where: Q_{corr} is the corrected volumetric flowrate for oxygen concentration
 O_{2norm} is the stated normalised oxygen percentage

To correct for temperature

$$Q_{normT} = Q_{corr} \times (273 / (273 + T_m))$$

Where: Q_{normT} is the normalised volumetric flowrate for temperature
 T_m is the measured temperature in degrees centigrade

To correct for pressure

$$C_{norm} = C_{normT} \times (P_m / 101.3)$$

Where: C_{norm} is the normalised volumetric flowrate
 P_m is the measured pressure in kPa

Appendix B: Conversion factors

ppm to mg/m³ - air

The conversion between ppm and mg/m³ is dependent on both the molecular weight of the substance and the temperature at which the conversion is made. The assumption is that the pollutant behaves as an ideal gas and as such, 1 mole of the substance occupies 22.4 litres at standard temperature (273K) and pressure (101.3 kPa). This is consistent with normalised concentrations, and it is therefore not normally necessary to take account of the temperature or pressure difference in the conversion. However, when converting ppm to mg/m³ at actual discharge conditions, it is important to take account of the necessary factors.

To convert from ppm to mg/m³, use the following formula:

$$\text{mg/m}^3 = \text{ppm} \times (\text{MM}/22.4) \times (273/\text{T}) \times (\text{P}/101.3)$$

Where
MW is the molar mass of the substance (in grams)
T is the temperature at which the conversion is to be made (degrees Kelvin)
P is the pressure at which the conversion is to be made (kPa)

To convert from mg/m³ to ppm, the following formulae should be used:

$$\text{ppm} = \text{mg/m}^3 \times (22.4/\text{MM}) \times (\text{T}/273) \times (1013/\text{P})$$

ppm to mg/l – Water

The conversion between ppm and mg/l for water is straightforward in that it is normally assumed that water has a density of 1000 kg/m³. On this basis, 1 ppm = 1 mg/l = 1 g/m³ = 1 mg/kg.

References and other information

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