Environmental Permitting Technical Note 1/1(18)

Reference document for combustion plant of 20 to 50 MW thermal capacity

Revised: xxx 2018

1 Legal Status

1.1 This note applies to the whole of the UK. It is issued by the Secretary of State, the Welsh Government, the Scottish Government and the Department of Agriculture, Environment and Rural Affairs in Northern Ireland (DAERA).

1.2 This note is issued as statutory guidance in England and Wales under regulation 65(1) of the Environmental Permitting Regulations; and in Northern Ireland under regulation 41(1) of the Pollution Prevention and Control (Industrial Emissions) Regulations. This note is also issued as guidance in Scotland. This note will be treated as one of the material considerations when determining any appeals against a decision made under this legislation.

1.3 This note supersedes:

- PG1/3(12), Statutory Guidance for Boilers and Furnaces 20-50MW thermal input;
- PG1/4(11) Statutory Guidance for Gas Turbines 20 – 50MW Thermal Input; and
- PG1/5(95) Secretary of State's Guidance-Compression Ignition Engines, 20-50 MW Net Rated Thermal Input.

2 Scope

2.1 England and Wales

This note applies to activities described in Schedule 1, Part 2, Chapter 1, Section 1.1, Part B (a) of the Environmental Permitting Regulations (England and Wales) 2016 as described below:

Part B
Unless falling within Part A(1) of this Section –
(a) burning any fuel in
  (i) a boiler,
  (ii) a furnace,
  (iii) a gas turbine, or
  (iv) a compression ignition engine,

With a net rated thermal input of 20 or more megawatts, but a rated thermal input of less than 50 megawatts.

Scotland

This note applies to the activity described in Schedule 1, Part 1, Chapter 1 Section 1.1 of the Pollution Prevention and Control (Scotland) Regulations 2012 as described below:

Part B
Unless described in Part A of this section –
(a) Burning any fuel in a boiler or furnace with a rated thermal input of more than 20 megawatts and less than 50 megawatts
(b) Burning any fuel in a gas turbine or compression ignition engine with a rated thermal input of more than 20 megawatts and less than 50 megawatts

Northern Ireland

This note applies to the activity described in Schedule 1, Part 1, Chapter 1, Section 1.1 of the Pollution Prevention Control (Industrial Emissions) (Northern Ireland) Regulations 2013 as described below:

Part C
(a) Unless falling within Part A of this section, burning any fuel, in a boiler or furnace or a gas turbine or compression ignition engine with, in the case of any of these appliances, a net rated thermal input of 20 megawatts or more but less than a rated thermal input of 50 megawatts.

2.2 This note does not apply to those plants of between 20 and 50 MW thermal input where they are one of a number of appliances with an aggregate rated thermal input of 50MW or more, operated on the same site by the same operator. These plants should be permitted as a single appliance with a rated thermal input of 50MW or more, Section 1.1 Part A(1)(a) (Part A in Scotland and Northern Ireland) and are subject to the BAT conclusions for large combustion plant (Commission Implementing Decision 2017/1442).

2.3 In England and Wales, the footnote in EPR to the activity description described above, says that where two or more appliances with an aggregate net rated thermal input of 20 or more megawatts are operated on the same site by the same operator, those appliances must be treated as a single appliance with a net rated thermal input of 20 or more megawatts.

In Scotland this is covered by a listed activity Part B "(c) Burning any fuel in a combination of appliances with a total rated thermal input of more than 20 megawatts and less than 50 megawatts in an installation to which Schedule 1A applies"

The EPR footnote is included to ensure those plants which fall within scope of the EU Energy Efficiency Directive 2012/27/EU carry out the cost benefit analysis on co-generation required by this Directive, However, compliance with the EED, is outside the scope of the note.

2.4 This note does not apply to any activities which fall within the scope of Chapter III of the EU Industrial Emissions Directive (2010/75/EU). Neither does Chapter III of the IED apply to the activities which are the subject of this note.

2.5 Other than as described in 2.7; from 20th December 2018, all plants within the scope of this note will come within the scope of the Medium Combustion Plant Directive (MCPD) 2015/2193/EU. The requirements of the MCPD have been built into Sections 4 and 5 of this reference document.

2.6 Other than as described in 2.7; all plants within the scope of this note that come into operation from 20th December 2018 will need to comply with the new plant requirements of MCPD.

For plants in operation before 20th December 2018; all plants within the scope of this note will need to comply with MCPD requirements for existing plant from 1st January 2025.

2.7 Where the plant meets one of the criteria in Article 2(3) of the MCPD, e.g. it is a furnace where the gaseous products of the combustion are used for the direct heating, drying or any other treatment of objects and material; then MCPD does not apply, but such plants will still need a Part B permit.

2.8 In England and Wales, the regulator for those plants described in 2.6 will be the Environment Agency or NRW respectively, otherwise the regulator will be the relevant Local Authority. In Scotland SEPA is the regulator for all plant. In Northern Ireland, the regulator will be NIEA in relation to Part A and B plant, while for Part C it will be the relevant District Council.

In England and Wales, if an MCP is part of a Part B or Part A2 installation, then the installation will have two environmental permits. One from the EA or NRW for the MCP and one from the local authority for the Part B or Part A2 activities. In Northern Ireland, if an MCP or generator is not part of a Part A or Part B installation, then the operator will need to have two permits. One from the District Council where the MCP is located and one from the Chief Inspector (NIEA) for the Part A or Part B activities.

2.9 In England and Wales, those plants which generate electricity will also be classified as 'specified generators' and subject to additional controls which are set out in Schedule 25B of the EPR. The requirements of Schedule 25B have been built into Sections 4 and 5 of this reference document.

Generators are divided into 2 groups, Tranche A and Tranche B:

Tranche A:

- Plants in operation before 1 December 2016
- Plants put into operation between 1st December 2016 and 19th December 2018 which are either:
    - the subject of a Capacity Market Agreement arising from the 2014 or 2015 auction; or
    - for which a Feed-in Tariff preliminary application had been received by Ofgem before 1 December 2016.

Tranche B:

- All other plants in operation on 20th December 2018, which are not Tranche A, other than back-up generators operating less than 50 hours per year (i.e. for testing purposes only).

Tranche B plants need to meet the relevant emission standards from 1st January 2019.

Tranche A plants where NO_X emissions to air are currently greater than 500 mg/Nm^3 (15% O_2) must meet the relevant emission standards from 1st October 2019. All other Tranche A plants will need to meet the relevant emission standards from 1st January 2025.

Where permit conditions need to be amended for Tranche A or B generators, regulation will move from control of the local authority to that of the Environment Agency or NRW as appropriate.

In Northern Ireland the controls on specified generators are set out in Schedule 9B of the Pollution Prevention and Control Regulations. The Tranches set out for England and Wales do not apply to Northern Ireland. For purposes of Schedule 9B generators are grouped as:
Existing Generator

- a generator with a rated thermal input equal to or greater than 1 megawatt and less than 50 megawatts which came into operation before 1st December 2016.

New Generator

- any specified generator which is not an existing

2.10 Note: the rated thermal input is taken to mean the net rated thermal input, i.e. that based on the net calorific value (or lower heating value) of the fuel, except for open cycle combustion plant burning gas or liquid fuel where rated thermal input is taken to mean the gross rated thermal input, i.e. that based on the gross calorific value (or upper heating value) of the fuel.

Except in Scotland, where it is defined in Regulations as follows: “rated thermal input is the rate at which fuel can be burned at the maximum continuous rating of the appliance multiplied by the net calorific value and expressed as megawatts thermal”.

3 General Conditions

3.1 In general terms, this note describes what is BAT for those activities falling within its scope. This note also, where appropriate, gives details of any mandatory requirements affecting air emissions which are in force (or about to come into force) at the time of publication. Unless otherwise stated, the provisions of this note are generally applicable.

3.2 The techniques listed and described in this reference document are neither prescriptive nor exhaustive. Other techniques may be used provided that they ensure at least an equivalent level of environmental protection.

3.3 Sections 4 and 5 set out a number of matters which should be considered for inclusion as permit conditions.

3.4 It is important to note, however, that this should not be taken as a short cut for regulators to a proper determination of BAT, e.g. where the combustion plant is a directly associated activity to another regulated process, BAT must be determined for the installation as a whole. In some circumstances, permit conditions including emission limit values based on BAT may be tighter than those set out in MCP. In individual cases it may be justified to:

a) include additional conditions;
b) include different conditions;
c) not include conditions relating to some of the matters indicated.

4 Summary of Best Available Techniques

4.1 Control of emissions to air

4.1.1 In order to reduce emissions to air of CO and unburnt substances from combustion plants, BAT is to ensure an optimised combustion.

An optimised combustion is achieved by good design and operation of the equipment, including optimisation of the temperature and residence time in the combustion zone, efficient mixing of the fuel and combustion air, and combustion control. Combustion control is based on the continuous monitoring and automated control of appropriate combustion parameters (e.g. O_2, CO, fuel to air ratio and unburnt substances).

4.1.2 In order to reduce NOx emissions to air from combustion plants, BAT is to use one or a combination of the primary techniques given below.

Table 4.1 Primary techniques for NO_x reduction

Technique	Description	Applicability
Choice of fuel	The use of fuel (including support/auxiliary fuel) with a low content of potential pollution generating compounds (e.g. lower sulphur, ash or nitrogen content in the fuel).	The switch from liquid to gaseous fuels may be restricted by the design of the burners in the case of existing plants.
Staged combustion	Staged combustion burners achieve lower NO_x emissions by staging the injection of either air or fuel in the near burner region. The division of fuel or air reduces the oxygen concentration in the primary burner combustion zone, thereby lowering the peak flame temperature and reducing thermal NO_x formation.	Applicability may be restricted by space availability when upgrading small plants, thus limiting the retrofit of fuel/air staging without reducing capacity.
Flue-gas recirculation (external)	Recirculation of part of the flue-gas to the combustion chamber to replace part of the fresh combustion air, with the effect of reducing the oxygen content and therefore cooling the temperature of the flame.	For existing plants, the applicability may be restricted by their design.
Flue-gas recirculation (internal)	Recirculation of part of the flue-gas within the combustion chamber to replace part of the fresh combustion air, with the effect of reducing the oxygen content and therefore reducing the temperature of the flame.	For existing plants, the applicability may be restricted by their design.
Low-NO_x burner (LNB) and ultra-low-NO_x burner (ULNB)	This technique is based on the principles of reducing peak flame temperatures, delaying but completing the combustion and increasing the heat transfer (increased emissivity of the flame). It may be associated with a modified design of the furnace combustion chamber. The design of ultra-low NO_x burners includes (air/) fuel staging and exhaust/flue-gas recirculation.	For existing plants, the applicability may be restricted by their design.

Technique	Description	Applicability
Use of inert diluents	'Inert' diluents, e.g. steam, water, nitrogen are used (either by being premixed with the fuel prior to its combustion or directly injected into the combustion chamber) to reduce the temperature of the flame. Steam injection may increase CO emissions.	Generally applicable.

4.1.3 In the event that primary techniques are not sufficient to control NO_x emissions below the emission limit value, BAT is to use one of the secondary techniques given below.

Table 4.2 Secondary techniques for NO_x reduction

Technique	Description	Applicability
Selective catalytic reduction (SCR)	The reduction of NO_x to nitrogen in a catalytic bed by reaction with ammonia (usually supplied as an aqueous solution) at an optimum operating temperature of around 300-450°C. One or more layers of catalyst may be applied.	Applicability to existing plant may be restricted by space availability.
Selective non-catalytic reduction (SNCR)	The reduction of NO_x to nitrogen by reaction with ammonia or urea at a high temperature. The operating temperature window must be maintained between 900°C and 1,050°C.	Applicability to existing process furnaces/heaters may be restricted by the temperature window (900-1,050°C) and the residence time needed for the reaction.

4.1.4 In order to prevent or reduce dust emissions to air from combustion plants BAT is to use one or a combination of the techniques given below.

Table 4.3 Techniques for dust reduction from combustion

Technique	Description	Applicability
Optimised combustion	See paragraph 4.1	Generally applicable
Choice of fuel	The use of a fuel with a lower pollution potential, e.g. liquid instead of solid fuel, gaseous fuel instead of liquid fuel.	For existing plant, the switch from one type of fuel to another may be restricted by the design of the plant.
Atomisation of liquid fuels	Use of high pressure to reduce the droplet size of liquid fuel. Current optimal burner design generally includes steam atomisation.	Applicable to liquid fuels.

4.1.5 In the event that the techniques above are not sufficient to control dust emissions below the emission limit value, BAT is to use one or a combination of techniques given below.

Table 4.4 Techniques for dust reduction from combustion

Technique	Description	Applicability
Cyclones / Multicyclones	Set of dust control systems, based on centrifugal force, whereby particles are separated from the carrier gas.	Solid fuel combustion plant.
Electrostatic precipitator	Electrostatic precipitators operate such that particles are charged and separated under the influence of an electrical field	Solid fuel combustion
Bag or fabric filter	Bag or fabric filters are constructed from porous woven or felted fabric through which gases are passed to remove particles.	Liquid and / or solid fuel combustion plant.
Ceramic or metal filter	Use of a ceramic filter material. In metal filters, surface filtration is carried out by sintered porous metal filter elements	Liquid and / or solid fuel combustion.

4.1.6 In order to prevent or reduce dust emissions to air from fuel and ash handling and storage, BAT is to use one of a combination of the techniques given below.

Table 4.5 Techniques for dust reduction from fuel/ash handling and storage

Techniques	Description	Applicability
Dust arrestment	Bag filters, cartridge filters	Silos
Dust suppression	Dust covers, water and/or suppressants, well positioned spray guns, sufficient coverage by sprays	Fuel / ash stockpiles
Appropriate siting	Away from site boundary especially if near residential or other sensitive receptors.	Outdoor operations, e.g. fuel stockpiles, conveyors, etc.
Wind dynamics management	Use of fencing, bunding, wind boards, enclosed conveyors, reduced drop heights, etc.	Outdoor operations, e.g. fuel stockpiles, conveyors etc.
Site and process design	Indoor storage, below ground or covered stock bins	Fuel stockpiles

4.1.7 In order to prevent or reduce SO_2 emissions to air from combustion plants, BAT is to use a fuel with a low sulphur content.

In the event that the emission limit value cannot be achieved by fuel choice, BAT is to use a suitable abatement technique, e.g. wet caustic scrubbing or dry scrubbing (i.e. in duct sorbent injection with hydrated lime or sodium carbonate/bicarbonate followed by dust abatement).

4.2 Control Techniques for biomass combustors

4.2.1 Fluidised combustion and travelling grates can meet a tighter limit for NO_x than stepped grate boilers, and fluidised bed or travelling grate should be preferred to stepped grate boilers. If the fuel is not suitable for fluidised bed combustion or a travelling grate, then a stepped grate boiler can be allowed.

4.2.2 Other parameters influencing the choice of biomass combustor, and its design include:

- Purpose: Energy generation, variation of load, CHP
- Fuel: %biomass, high N CI, slagging characteristics,
- Form:
  - EN14961-1 Table 1 lists: briquettes, pellets, wood chips, hog fuel, wood logs, sawdust, shavings, bark, bales, energy grain, olive residues, fruit seed, others.
  - And as an example, the specification for pellets includes: Origin, dimensions, moisture, bulk density, fines, additives, net calorific value as received, mechanical durability; and in certain cases sulphur, chlorine, nitrogen content.
- Aquatic biomass, blends and mixtures
- Fuel indexes

4.2.3 The effect of the parameters can include:

- High moisture content can be limiting by effect on heat balance
- Difficult ash behaviour – slagging in the fire bed, and fouling on furnace and boiler surfaces
- Difficult physical properties – bale handling equipment, metering and feeding materials to combustor
- Deposit build-up on boiler tubes requires removal for thermal and corrosion reason.

4.2.4 Techniques to predict fuel behaviour from bio-fuel analysis are still being developed.

4.2.5 Biomass combustor designs are actively being developed: e.g. control techniques include fuel and air staging, flue gas recirculation, fuel bed cooling.

4.3 Techniques to control emissions from storage and handling of fuels and ash

4.3.1 When delivering, moving or removing materials, loading to and from stock piles should be carried out so as to prevent emissions to the air.

4.3.2 The transport and handling of dusty materials within the site should be carried out by methods which prevent emissions to the air. External above – ground conveyors carrying dusty materials should be fitted with protection against wind whipping. Transfer point extraction should be ducted to suitable arrestment equipment to meet the limit values in section 5 below.

4.3.3 All vehicles transporting dry, dusty materials to or from a site should be totally enclosed or adequately sheeted to prevent escape of particulate matter to the air.

4.3.4 All dusty materials should be stored in covered containers, purpose-built silos or undercover whenever practicable.

4.3.5 Stockpiles of dusty, or potentially dusty, materials should be stored so as to prevent wind whipping e.g. by covering, screening or dampening.

4.3.6 Bulk fuel storage and silos should be fitted with a high-level alarm or volume indicator to warn of and thereby prevent overfilling. For example for chipped fuels.

- The high-level alarm should be electronically interlocked with the fuel delivery system in order to prevent overfilling.
- Deliveries of chipped fuels should be supervised at all times.

4.3.7 Silos for the storage of solid fuels should be vented to air through suitable arrestment equipment, to meet the emission concentration limits specified in section 5 below.

4.3.8 All arising's of ash and other dusty materials should be stored in closed containers or buildings or stored in a wet state pending removal from site.

4.3.9 All on-site fuel processing activities such as chipping, shredding, pulverising or screening should be conducted so as to minimise releases of dust to air. Such activities should take place inside a building.

4.3.10 Bulk storage tanks for liquid fuels should wherever practicable be back vented to the delivery tank during filling. Where this is impracticable, displaced air vents should be sited in such a way as to prevent the arising of offensive odour, as perceived by the local enforcing authority inspector at or beyond the site boundary.

4.3.11 Above-ground fuel storage tanks should be completely contained by bunding which is impervious and resistant to the fuels in storage and capable of holding 110% of the capacity of all storage tanks within the bund.

4.3.12 Adequate provision should be made for the containment of liquid and solid spillages. All spillages should be cleared as soon as possible and in the case of solid materials this should be achieved by the use of vacuum cleaning, wet methods or other appropriate techniques. Dry sweeping should not be permitted.

4.4 Air quality, dispersion and dilution

4.4.1 Pollutants that are emitted via a stack require sufficient dispersion and dilution in the atmosphere to ensure that they ground at concentrations that are deemed harmless.

4.4.2 Emissions to air should be free from dark smoke (see 5.4) and from offensive odour outside the site boundary, as perceived by the regulator. Good combustion should achieve that aim.

4.4.3 All new installations should submit an air quality report which details the long term and short term process contribution as part of their application. The process contribution can be calculated using the Environment Agency H1 guidance.

4.4.4 Emissions from the permitted process or installation shall not contribute significantly to any exceedance of EU air quality limit values or objectives of

the air quality strategy for England, Scotland, Wales and Northern Ireland for sulphur dioxide, oxides of nitrogen and particulate matter (PM_{10} and $PM_{2.5}$).

4.4.5 In areas where air quality standards or objectives are being breached or are in serious risk of breach and it is clear from the air quality report or detailed review and assessment (for existing installations) that the permitted process or installation itself is a significant contributor to the problem, it is likely that the regulator will impose tighter emission limits than those set out in tables 5.2 to 5.6 of this Technical Note. The need for tighter emission limits might be offset, fully or in part, by increasing the stack height and/or exit velocity.

4.4.6 The aim should be to ensure that the process contribution is no more than 1% of the relevant long term EQS and/or 10% of the relevant short term EQS at sensitive receptors, which could include designated Habitats and wildlife sites as well as residential locations. Where this cannot be demonstrated through simple calculation, (E.g. the Environment Agency's H1 methodology), the applicant will need to use computer based air dispersion models (e.g. ADMS, AERMOD) or some form of intermediate screening tool.

Where it cannot be shown to be no more than 1% of the long term EQS and/or 10% of the short term EQS, representative data on background levels of pollution will be needed to fully assess the impact of emissions.

Note when assessing the impact of particulate emissions (PM_{10} and $PM_{2.5}$), a first assumption will normally be to assume that all the dust emissions are PM_{10} or $PM_{2.5}$. Data on particle size distribution of dust emissions may be needed where the process contribution cannot be shown to be no more than 1% of the long term EQS and/or 10% of the short term EQS at sensitive receptors using this initial assumption, as an alternative to, or in combination with more detailed assessment methodologies.

4.4.7 Where necessary the regulator should include the minimum stack height and exit velocity within the environmental permit.

4.4.8 In order to ensure dispersion is not impaired by either low exit velocity at the point of discharge, or deflection of the discharge, a cap, or other restriction, should not be used at the stack exit. However, a cone may sometimes be useful to increase the exit velocity to achieve greater dispersion.

4.5 Emission testing

4.5.1 Where annual emission testing is required it is essential that the operator has sufficient monitoring locations for testing. Guidance on testing locations can be found in the Environment Agency's Technical Guidance Note (Monitoring) M1: Sampling requirements for stack monitoring or appropriate regulator's guidance. It is also advisable for the operator to employ the services of an emissions testing company before they apply for a permit to determine if emissions monitoring can be undertaken.

4.5.2 Where emissions monitoring is required but cannot be safely or correctly undertaken the regulator should refuse the permit.

4.5.3 If considered necessary the regulator should include permit conditions detailing the requirements needed, (e.g. design, access, etc.) to undertake periodic emissions testing.

4.6 Management

4.6.1 Effective management is central to environmental performance; it is an important component of BAT and of achieving compliance with permit conditions. It is therefore desirable that installations put in place some form of structured environmental management system that addresses the following areas.

a) Cleaning and maintenance
b) Training and plant operation
c) Bottom ash disposal
d) Emission monitoring
e) Plant failures
f) Record keeping

If the operator already has a published standard (i.e. ISO 14001) they do not need to set up a separate system. Regulators should use their discretion, in consultation with individual operators, to agree the appropriate level of EMS dependent to the nature and size of the particular process.

4.7 Cleaning and maintenance

4.7.1 Effective preventative maintenance and cleaning plays a key role in achieving compliance with emission limits.

4.7.2 Regular cleaning of the flues and ductwork should be undertaken to ensure that dispersion rates are not affected by a build-up of material

4.7.3 All aspects of the process including all plant, buildings and equipment should be maintained in line with manufactures recommendations. Where there are no manufactures recommendations then the operator should devise their own maintenance procedures.

4.8 Training and operation

4.8.1 In order to minimise the risk of emissions during operation all plant should be operated in accordance with the manufactures operating manual. Where there is not a manufacturing operating manual the operator should develop their own operating procedures that includes plant failures.

4.8.2 Only staff that are trained should be authorised to operate the plant.

4.9 Record keeping

4.9.1 It is important that the operator can prove their compliance with all permit conditions so it is recommended that the operator keeps records of:

(a) All inspections both by external bodies and internal employees,

(b) Maintenance including cleaning, maintenance undertaken by external contractors or internal personnel and breakdowns,

(c) Operating procedures with subsequent training records,

(d) Emission testing, periodic and operator assessment and as well as details of any testing platforms.

And makes available these records to the regulator when requested.

4.9.2 In addition for medium combustion plants the operator shall keep a record of:

a) the type and quantities of fuels used in the plant

b) information proving the effective continuous operation of secondary abatement equipment needed in order to meet the emission limit values; and,

c) any malfunctions or breakdown of secondary abatement equipment.

4.9.3 Records must be kept for a minimum of 6 years.

5. Emission limits, Monitoring and Other Provisions

5.1 Emissions Monitoring

5.1.1 Emissions of the substances listed Table 5.1 below should be controlled. The emission limit values and other provisions described in this section are achievable using the best available techniques described in Section 4.

5.1.2 Monitoring of emissions should be carried out according to the standard and with at least the minimum frequency specified in table 5.1 or by an equivalent method agreed by the regulator. Measurements shall be carried out for those pollutants for which an emission limit value is set and for carbon monoxide for all plants. Where reference is made to a British, European, or International standard (BS, CEN or ISO) in this section, the standards referred to are correct at the date of publication.

Table 5.1 Emission monitoring frequencies and standards.

Substance/ Parameter	**Standard ([1])([2])**	**Minimum monitoring frequency ([2])**
Carbon monoxide	EN 15058	Once every year ([5])
Dust ([3])	EN 13284-1	
Oxides of Nitrogen (NO and NO_2, expressed as NO_2)	EN 14792	
Sulphur dioxide ([4])	EN 14791	
Smoke (Ringlemann)	BS 2742:2009	Daily when in operation

([1])The standard referred to are correct at the date of publication. Users of this note should bear in mind that the standards are periodically amended, updated or replaced. The latest information regarding the monitoring standards applicable can be found at the Source Testing Association website. Further information on monitoring can be found in Environment Agency publications (M1) and (M2).
([2]) Where continuous measurements are made the relevant EN standards are EN 15267-1, -2 and -3 and EN 14181, which are applicable to all parameters.
([3]) Monitoring of dust does not apply when combusting gaseous fuels only.
([4]) In the case of emissions of sulphur dioxide from combusting fuels with a known sulphur content, monitoring can be replaced emissions may be calculated by calculation ensuring the provision of data of an equivalent scientific quality.
([5]) For plants which operate for less than 500 hours per year, the minimum monitoring frequency is once every 500 operating hours or once every 5 years, whichever comes first.

5.1.3 For newly permitted plant, the first measurements shall be carried out within four months of the grant of a permit or of the date of the start of the operation, whichever is the latest.

5.1.4 In determining whether more frequent monitoring than that set out in tables 5.2 to 5.5 or continuous monitoring is required. The regulator should have regard to the following factors:

- the level of risk to local air quality or other sensitive receptors;
- variability in operating conditions, e.g. waste types and feed rate;
- absence of secondary dust abatement or reliance on cyclones.

In the case of continuous measurements, the automated measuring systems shall be subject to checking by means of parallel measurements with the reference methods at least once per year and the operator shall inform the regulator about the results of those checks.

5.1.6 During each measurement, the plant shall be operating under stable conditions at a representative even load. In this context, start-up and shut-down periods shall be excluded.

5.1.7 Whether sampling on a continuous or non-continuous basis care is needed in the design and location of sampling systems in order to obtain representative samples for all release points.

- Sampling points on new plant should be designed to comply with the British or equivalent standards, see paragraph above.
- The operator should ensure that relevant stacks or ducts are fitted with facilities for sampling which allow compliance with the sampling standards.

5.2 Emission Limit values

5.2.1 All activities should comply with the emission limits and other provisions with regard to releases specified in Tables 5.2 to 5.6.

5.2.2 Unless stated otherwise, the emission limit values refer to values of concentration, expressed as mass of emitted substance per volume of waste gas under standard conditions (dry gas at a temperature of 273.15K and a pressure of 101,3 kPa), and expressed in the unit mg/Nm3. The reference oxygen level of the waste gases is 6 vol-% for solid fuels, and 3 vol-% for liquid and gas fuels, other than engines and gas turbines and 15 vol-% for engines and gas turbines.

5.2.3 Unless stated otherwise, the averaging periods associated with the ELVs for emissions to air are defined, for periodic monitoring, as the average over the sampling period i.e. the average of three consecutive measurements of at least 30 minutes each.

Table 5.2 Emission limit values for emissions to air from boilers and furnaces combusting solid fuels

Substance / Parameter	Emission Limit Value (mg/Nm^3)	Fuel ([1])	Type of Plant
Sulphur dioxide (SO_2)	3000	Coal (indigenous coal)	Existing plants until 31st December 2024
	2000	Coal (non-indigenous coal)	
	400	All solid Fuels (other than biomass)	New plants and existing plants from 1st January 2025.
	200	Solid biomass	All plants

Table 5.2 Emission limit values for emissions to air from boilers and furnaces combusting solid fuels (continued)

Substance / Parameter	Emission Limit Value (mg/Nm^3)	Fuel ([1])	Type of Plant
Oxides of Nitrogen (NOx)	650 ([2])	Coal	Existing plants until 31st December 2024
	650 ([2])	All solid fuels (other than biomass)	Existing plants from 1st January 2025.
	300		New plants
	250 ([3])	Solid biomass	All plants
Dust	300	Coal	Existing plants until 31st December 2024
	50	Solid biomass	
	30	All solid fuels	Existing plants from 1st January 2025.
	20		New plants
Carbon monoxide (CO)	No limit ([4])	All solid fuels	All plants

([1]) Unless stated otherwise, the reference to solid fuels other than biomass shall include coal.
([2]) For stoker firing furnaces using coal as a fuel the limit is 450 mg/Nm^3.
([3]) For stepped grates the limit is 300 mg/Nm^3.
([4]) No ELV is applied for CO. As an indication, the CO emission level will generally be less than 150 mg/Nm^3.

Table 5.3 Emission limit values for emissions to air from boiler and furnaces combusting liquid fuels

Substance / Parameter	Emission Limit Value (mg/Nm^3)	Fuel ([1])	Type of Plant
Sulphur dioxide (SO_2)	S content of fuel limited to 1% w/w	Heavy fuel oil	Existing plants until 31st December 2024
	350	Liquid fuels other gas oil	New plants and existing plants from 1st January 2025
	S content of fuel limited to 0.1% w/w	Gas oil	All plants
Oxides of Nitrogen (NOx)	450	Liquid fuels other than gas oil	Existing plants
	300		New plants
	200	Gas oil	All plants
Dust	150	Heavy fuel oil	Existing plants until 31st December 2024
	100	Gas oil	
	30	All liquid fuels	Existing plants from 1st January 2025
	20		New plants
Carbon monoxide (CO)	No limit ([2])	All liquid fuels	All plants

([1]) Unless stated otherwise, reference to liquid fuels other than gas oil shall include heavy fuel oil.
([2]) No ELV is applied for CO. As an indication, the CO emission level will generally be less than 150 mg/Nm^3.

Table 5.4 Emission limit values for emissions to air from boilers and furnaces combusting gaseous fuels

Substance / Parameter	Emission Limit Value (mg/Nm^3)	Fuel	Type of Plant
Sulphur dioxide (SO_2)	No limit	Natural gas	All plants
	35 ([1])([2])	Gaseous fuels other than natural gas	New Plants and existing plants from 1st January 2025
Oxides of Nitrogen (NOx)	140	Natural gas	Existing plants
	100		New plants
	250	Gaseous fuels other than natural gas	Existing plants from 1st January 2025
	200		New plants
Carbon monoxide (CO)	No limit ([3])	All gaseous fuels	All plants
([1]) The limit for low calorific value gases from coke ovens is 400 mg/Nm^3. The limit for low calorific value gases from blast furnaces is 200 mg/Nm^3. ([2]) The limit for biogas is 170 mg/Nm^3 for existing plant and 100 mg/Nm^3 for new plant. ([3]) No ELV is applied for CO. As an indication, the CO emission level will generally be less than 100 mg/Nm^3.			

Table 5.5 Emission limit values for emissions to air from gas turbines

Substance / Parameter	Emission Limit Value (mg/Nm^3)	Fuel	Type of Plant ([4])
Sulphur dioxide (SO_2)	S content of fuel limited to 0.1%w/w	Gas oil	All plants
	15 ([1])([2])	Gaseous fuels other than natural gas	New plants and existing plants from 1st January 2025
	120	Liquid fuels other than gas oil	
Oxides of Nitrogen (NOx)	125	Natural gas	Existing plants in operation prior to 6th October 2004
	60		Existing plants in operation from 6th October 2004
	50		New plants
	165	Liquid fuels or LPG	Existing plants in operation prior to 6th October 2004
	125		Existing plants in operation from 6th October 2004
	75	Liquid fuels and gaseous fuels other than natural gas	New plants
Dust	10	Liquid fuels other than gas oil	New Plants and existing plants from 1st January 2025

Table 5.5 Emission limit values for emissions to air from gas turbines (continued)

Substance / Parameter	Emission Limit Value (mg/Nm^3)	Fuel	Type of Plant ([4])
Carbon monoxide (CO)	No limit	All fuels	Existing plants in operation prior to 6th October 2004
	60 ([3])		All plants other than those in operation prior to 6th October 2004.
([1]) For existing plants, the limit for low calorific value gases from coke ovens is 130 mg/Nm^3 and the limit for low calorific value gases from blast furnaces is 65 mg/Nm^3. ([2]) The limit for biogas is 60 mg/Nm^3 for existing plant and 40 mg/Nm^3 for new plant. ([3]) The CO limit only applies when the plant is operating above 70% load. ([4]) In England and Wales, new plants also include Tranche B generators.			

Table 5.6 Emission limit for emissions to air from compression ignition engines

Substance / Parameter	Emission Limit Value (mg/Nm^3)	Fuel	Type of Plant ([2])
Sulphur dioxide (SO_2)	S content of fuel limited to 0.1% w/w	Gas oil	All plants
	120	Liquid fuels other than gas oil	New plants and existing plants from 1st January 2025
Oxides of Nitrogen (NOx)	500	All liquid fuels	Existing plants until 31st December 2024 ([3])
	190([1])		New plants and existing plants from 1st January 2025
Dust	50	All liquid fuels	Existing plant until 31st December 2024
	10		New plants and existing plants from 1st January 2025
Carbon monoxide (CO)	No limit	All liquid fuels	All plants
([1]) For dual fuel engines in liquid mode the limit is 225 mg/Nm^3. ([2]) In England and Wales, new plants also include Tranche B generators. ([3]) In England and Wales, plants unable to achieve the 500 mg/Nm^3 will be required to apply for a new permit and achieve 190 mg/Nm^3 no later than 1st October 2019.			

5.2.4 Where a boiler or furnace is fired simultaneously with two or more fuels (co-firing), the following formula should be used to calculate the emission limits that will apply when the boiler or furnace is being fired this way:

$$Emission = \frac{[MWth\ (fuel\ a) x\ ELV\ (fuel\ a) + MWth\ (fuel\ b) x\ ELV\ (fuel\ b) etc.]}{Total\ thermal\ input\ from\ all\ fuels}$$

5.3 Compliance with emission limit values

5.3.1 Compliance monitoring can be carried out either by use of a continuous emission monitor (CEM), or by a periodic extractive measurements.

5.3.2 In the case of periodic measurements, the emission limit values referred to in Tables 5.2 to 5.6 shall be regarded as having been complied with if the results of each of the measurements or of the other procedures do not exceed the relevant emission limit value.

5.3.3 In the case of continuous measurements, the emission limit values shall be regarded as having been complied with if the evaluation of the measurements results indicates, for operating hours within a calendar year, that all of the following conditions have been met:

(a) No validated monthly average value exceeds the relevant emission limit values;
(b) No validated daily average values exceeds 110% of the relevant emission limit values;
(c) In cases of combustion plants composed only of boilers using coal, no validated daily average value exceeds 150% of the relevant emission limit values;
(d) 95% of all the validated hourly average values over the year do not exceed 200% of the relevant emission limit values.

The validated hourly and daily average values shall be determined from the measured valid hourly average values after having subtracted the value of the confidence interval specified below.

At the emission limit value, the values of the 95% confidence intervals of a single measured result shall not exceed the following percentages of the emission limit values:

Carbon monoxide	10%
Sulphur dioxide	20%
Nitrogen dioxide	20%
Dust	30%

Any day in which more than three hourly average values are invalid due to malfunction or maintenance of the automated measuring system shall be invalidated. If more than 10 days over a year are invalidated for such situations the regulator shall require the operator to take adequate measures to improve the reliability of the automated measuring system.

5.4 Other emissions to air

5.4.1 Emission from combustion processes, including gas turbines should, in normal operation, be free from visible smoke.

5.4.2 During start-up and shut-down combustion emission of smoke should not exceed the equivalent of Ringelmann Shade 1.

5.4.3 For gas turbines, a monitor for visible emissions should be calibrated to sound an audible alarm in the event of smoke emissions exceeding the equivalent of

Shade 1 on the Ringelmann chart. Events when this limit is exceeded should be recorded.

5.4.4 All other releases to air other than condensed water vapour, including emission from materials handling operations, should be free from persistent visible emissions.

5.5 Other than normal operating conditions

5.5.1 Higher emissions may occur during start-up and shut-down of a process. These emissions can be reduced, by minimising, where possible, the number of start-up and shut-downs and having adequate procedures in place for start-up, shut-down and emergency shut-downs.

5.6 Reporting and Notifications

5.6.1 Communication between the operator and the regulator is essential for an effectively regulated installation.

5.6.2 Where an operator undertakes periodic emissions monitoring, the operator should notify the regulator, sufficiently in advance, of the monitoring exercise taking place to allow the regulator to witness the testing.

5.6.3 Subsequently the operator should submit the results of any periodic emission testing to the regulator once they have received the results. This submission should be within a timescale and format agreed with the regulator.

Notwithstanding the requirements of paragraph 5.6.5, where an operator undertakes continuous emissions monitoring, the operator should report all results (including the results of parallel measurements using the relevant reference method) at least annually, or more frequently if required by the regulator. This submission should be within a timescale and format agreed with the regulator.

5.6.4 Where monitoring is not in accordance with the main procedural requirements of the relevant standard, deviations should be reported as well as an estimation of the error involved.

5.6.5 In the event of any non-compliance with any emission limit value, or malfunctions and breakdown of the plant that leads to abnormal operating conditions or complaints about odour and / or smoke; the operator shall take the measures necessary to ensure that compliance is restored within the shortest possible time. This action should include but is not limited to:

a) Notify the regulator within 24 hours of receiving the information to agree the investigation of the issue.
b) Undertake the agreed investigation.
c) Adjust the process or activity to minimise those emissions.
d) If applicable re-test to demonstrate compliance as soon as possible.
e) Promptly record the events and actions taken.
f) Submit to the regulator the report and updates as agreed.

5.6.6 The operator should inform the regulator, without undue delay, of any proposed changes to the plant which could affect the applicable emission limit values. This notification should be sufficiently in advance of those changes coming into effect for the regulator to make the necessary assessments with a view to varying the permit as appropriate.