How to comply with your environmental permit
Additional guidance for:

Combustion Activities (EPR 1.01)

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Contents

Introduction

Introduction

In *"Getting the basics right – how to comply with your environmental permit"* (GTBR) we described the standards and measures that we expect businesses to take in order to control the risk of pollution from the most frequent situations in the waste management and process industries.

This sector guidance note (SGN) is one of a series of additional guidance for Part A(1) activities listed in Schedule 1 of the Environmental Permitting Regulations (the Regulations). We expect you to use the standards and measures in this note **in addition** to those in GTBR to meet the objectives in your permit.

Sometimes, particularly difficult issues arise such as problems with odour or noise. You may then need to consult the "horizontal" guidance that gives in depth information on particular topics. Annex 1 of GTBR lists these.

The IPPC Directive requires that the Best Available Techniques (BAT) are used. When making an application, explain how you will comply with each of the indicative BATs in this sector guidance note. Where indicative BAT is not included, where you propose to use an alternative measure or where there is a choice of options you should explain your choice on the basis of costs and benefits. Part 2 of Horizontal Guidance Note H1 Environmental Risk Assessment (see GTBR Annex 1) gives a formal method of assessing options which you should use where major decisions are to be made.

We will consider the relevance and relative importance of the information to the installation concerned when making technical judgments about the installation and when setting conditions in the permit.

Modern permits describe the objectives (or outcomes) that we want you to achieve. They do not normally tell you how to achieve them. They give you a degree of flexibility.

Where a condition requires you to take appropriate measures to secure a particular objective, we will expect you to use, at least, the measures described which are appropriate for meeting the objective. You may have described the measures you propose in your application or in a relevant management plan but further measures will be necessary if the objectives are not met.

The measures set out in this note may not all be appropriate for a particular circumstance and you may implement equivalent measures that achieve the same objective. In cases where the measures are mandatory this is stated.

Introduction

In response to the application form question on Operating Techniques, you should address each of the measures described as indicative BAT in this note as well as the key issues identified in GTBR.

Unless otherwise specified, the measures and benchmarks described in this note reflect those of the previous Sector Guidance Note. They will be reviewed in the light of future BREF note revisions. In the meantime we will take account of advances in BAT when considering any changes to your process.

Installations covered

This note applies to activities regulated under the following section of schedule 1 of the Regulations:

Section 1.1 Combustion Activities, Part A(1) :

(a) Burning any fuel in an appliance with a rated thermal input of 50 megawatts or more. The reference to thermal rated input shall be taken to refer to gross, not net, input.

(b) Burning any of the following fuels in an appliance with a rated thermal input of 3 megawatts or more, but less than 50 megawatts, unless the activity is carried out as part of a Part A (2) or B activity -

  (i) waste oil;
  (ii) recovered oil;
  (iii) any fuel manufactured from, or comprising, any other waste.

Selected activities of Section 1.2 Part A(1):

(e) Producing gas from oil or other carbonaceous material or from mixtures thereof, other than from sewage, unless the production is carried out as part of an activity which is a combustion activity (whether or not that combustion activity is described in Section 1.1).

(j) Activities involving the pyrolysis, carbonisation, distillation, liquefaction, gasification, partial oxidation, or other heat treatment of coal (other than the drying of coal), lignite, oil, other carbonaceous material or mixtures thereof otherwise than with a view to making charcoal.

Operators of landfill gas engines should refer to LFTGN 6 Guidance on gas treatment technologies for Landfill Gas Engines[1]

Appliances operated on the same site by the same operator should be aggregated. This note applies if the total exceeds 50MW. This includes those rated <3 MWth and standby plant.

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[1] goto http://www.environment-agency.gov.uk/commondata/acrobat/lftgn06_treatment_936556.pdf

Introduction

Directly associated activities

The installation will also include **directly associated activities**, which have a direct technical connection with the main activities, and which may have an effect on emissions and pollution. These may involve activities such as:

- the storage and handling of raw materials; the storage and despatch of finished products, waste and other materials
- the control and abatement systems, where not an integral part of the activity
- waste treatment or recycling.

Tables 3.1 and 3.2 (Annex 3) provide information regarding which part of the regulations apply to your plant.

Certain biomass wastes are exempt from the requirements of WID. For further information refer to IPPC Co-Incineration Supplement, http://www.environment-agency.gov.uk/commondata/acrobat/coincinerator_924475_924475.pdf

For a new plant with a multi-fuel firing unit involving the simultaneous use of two or more fuels, the LCPD sets the method by which emissions limit values should be calculated.

Plaster processes are included in this sector because of the aggregation rule. This part of the combustion sector differs as it uses combustion techniques to modify mineral properties within its processes and does not generate power or steam.

Key issues

The key issues are:

Key emissions to air

- sulphur dioxide
- nitrogen oxides
- particulate matter, particularly from solid fuel fired plants
- trace substances, such as heavy metals and dioxins.

In any combustion activity, there is an inter-relation between the CO concentration, NOx concentration, carbon in ash and thermal efficiency. Combustion should be controlled to provide an optimum compromise between these factors.

Global warming

Global warming is addressed under climate change levy agreements and/or the Greenhouse Gas Emissions Trading Regulations. This environmental permit considers basic energy efficiency measures.

Introduction

Burning alternative fuels

Where these fuels are classified as wastes, plants will be classified as co-incineration plants under the Waste Incineration Directive (WID). The relevant emission limits given within that Directive will apply.

Releases to land

Ash and residues from air pollution control equipment require disposal. Where possible, these should be recycled e.g. in the manufacture of gypsum and cement manufacture. The Landfill Directive requires specialist pre-treatment of some residues before they can be landfilled.

Releases to water

Cooling water discharge is usually the key release. There may also be some aqueous discharges from air pollution control equipment.

1

Managing your activities

Energy efficiency

1. Managing your activities

1.1 Energy efficiency

For power generating cycles, the maximum theoretical (thermodynamic) efficiency is obtained by maximising the working temperature difference. This implies high combustion temperatures and minimising the temperature at which heat is rejected from the cycle.

Fuel should be combusted as completely as possible and the heat generated should be transferred efficiently to the working medium, usually water in the case of boilers.

In addition to efficient boiler heat transfer design, further efficiency improvements may be obtained by optimal heat recovery through combustion air preheating and feedwater heating. Practical limits are reached by the tendency for increased NOx formation with high air preheating and by the risk of condensation and corrosion by overcooled stack gases. You should account for these factors when designing plant.

Indicative BAT

You should where appropriate:

1. Demonstrate that the proposed or current situation represents BAT where there are other considerations involved, e.g. recovering energy from waste affects the energy efficiency of the process.

Boilers and furnaces

2. Carry out regular checks to minimize leakage of air into units operating below atmospheric pressure.
3. Ensure good design, operation and maintenance of burners.

Steam turbines

4. Replace existing turbines with more efficient turbines.
5. Increase cycle efficiency by measures such as reheating steam between stages, improving the vacuum on condensers and using very high, including supercritical, pressures to increase the working temperature difference and cycle efficiency.
6. Take steam from between stages or from a backpressure exhaust for use in, for example, process or building heating.

Energy efficiency

Gas turbines

7. In large installations, consider installing more than one smaller turbine to allow for more efficient load following.
8. Consider measures to improve the efficiency of the turbine:
   - increasing the combustion temperature, but balanced against increase NOx levels and amounts of excess air required
   - using concentric shafts to connect different stages of compression and expansion - this is common in aero derivative machines
   - intercooling between stages of air compression and reheating between stages of expansion. Such features are normally incorporated at the design stage and may not be relevant to retrofits
9. The exhaust from even the most efficient gas turbines contain large amounts of heat that should be recovered, and used for process or building heating (CHP), or steam may be fed to a steam turbine to provide additional power in a combined cycle (CCGT). Supplementary fuel may also be fired in the heat recovery boiler to meet the heat demands. The design of the system needs to optimize the characteristics of the turbines and boiler to achieve the best overall performance.

Reciprocating engines

10. Maximise engine efficiency by measures such as turbo charging and air intercooling. However, this should be balanced against increased NOx emissions.
11. Recover exhaust gas heat for process or building heating or absorption chilling.
12. Recover lower-grade heat from engine coolants.
13. Where additional heat is required, supplementary fuel may be fired into the boiler, although this can be complicated by the pulsating exhaust and size limitations.

(These features are usually incorporated at the design stage.)

Avoidance, recovery and disposal of wastes

1.2 Avoidance, recovery and disposal of wastes

Indicative BAT

You should where appropriate:

1. Store, handle and transport all waste streams to prevent the release of waste, dust, VOC, leachate or odour.
2. Store bottom ash and fly ash separately. This provides flexibility to re-use the different ash fractions.
3. Where scale allows, store ash fractions and other dusty residues in closed silos fitted with high level alarms and dust abatement plant.
4. Explore markets for waste streams, for example:
    - bottom ash for aggregate
    - PFA for cement manufacture and construction products
    - FGD gypsum and fused slags for construction products
5. Recycle materials back into the process whenever possible, e.g. re-using partially reacted lime.
6. Where recycling or re-use is not possible, then consider regeneration of other materials or return to the manufacturer e.g.:
    - ion exchange resins
    - reverse osmosis membranes
    - molecular sieves
    - catalysts

2

Operations

Liquid fuels
Gaseous fuels

2. Operations

2.1 Liquid fuels

Air: The in-furnace techniques for controlling releases of NOx and particulates are based on burner design, the method of atomization and the control of primary, secondary and tertiary air. A control loop system is required to govern the air and fuel supply and is significant in air pollution control. Such techniques may not be practical for small installations using compact, high thermal rating combustion chambers.

Solids removal from the fuel may be required. Efficient atomisation of oil fuels is necessary and fuel viscosity at the burners is a primary consideration. Oil (including bitumen) emulsions and many heavy fuel oils have high sulphur contents and may have high vanadium and nickel contents. The use of oil fuels containing sulphur will result in some sulphur trioxide releases, as well as sulphur dioxide. Where low sulphur oils (below 1% w/w sulphur) are used, this may preclude the need for flue gas desulphurisation (FGD). The Sulphur Content Of Liquid Fuels Regulations 2000 (SCOLF) allows for derogation from this limit where the Emission Limit Values set out in LCPD are met.

2.2 Gaseous fuels

These include natural gas and others, e.g. mine gas; vaporised LPG, refinery gas and gases from the production of smokeless fuel; together with that from the gasification of coal, oil or other carbonaceous matter in a separate plant, or the underground gasification of coal.

Air: If a plant designed for and normally operated on gaseous fuel not requiring the use of flue gas treatment, has to use standby fuel because of an interruption in the gas supply, then for short periods only such plant may be allowed to operate without flue gas treatment.

Indicative BAT

1. You should inform us, and the local authority, when standby fuel is used, and when you return to gas firing.

3

Emissions and monitoring

Point source emissions to water

3. Emissions and monitoring

3.1 Point source emissions to water

Generally, waste water can arise from:
- the process
- rain-water run-off where there is the potential for contamination
- storm water
- cooling water
- treatment of accidental releases of raw materials, products or waste materials
- fire-fighting.

At sites with large boilers and furnaces the following sources of waste streams to water are the most significant:
- **Coal storage** - leachate from coal stacks is governed by the coal composition. In particular the presence of pyrite (iron sulphide) and a low pH can cause pollution. Acidic conditions may increase mobility of trace metals, contributing to the polluting effect of the leachate.
- **Oil storage** - leakage from oil storage areas can cause pollution.
- **De-ionisation effluent** - water de-ionisation plant regeneration effluent will usually be produced as an acid stream and an alkali stream, which are mixed together and pH adjusted for disposal. This effluent contains all the dissolved solids in the original water supply and any undissolved solids which may be present, particularly where river or estuary water is used. Soluble sulphates are also likely to be present where sulphuric acid is used for regeneration of the ion exchange material. The presence of salts in the release should be considered.
- **Boiler blowdown** - during normal operations boilers are blown down to control the composition of the boiler water. This blowdown is a concentration of the small amounts of solids remaining in the boiler feed water from the water de-ionisation plant, plus any chemicals used for treating the water, e.g. phosphates, small amounts of alkalis, hydrazine, ammonia etc .
- **Process water (e.g. wet scrubbing)** – the effluent will be acidic and be likely to contain metals, solids and organics.
- **Cleaning liquids** - Wash waters and cleaning-out solutions arising from the maintenance of boiler plant may contain organic acids, alkalis, alkali phosphates, iron oxides in suspension, complex corrosion inhibitors, and hydrochloric or hydrofluoric acid.
- **Waste water treatment** - many sites will have on-site wastewater treatment plants for treating domestic wastes and suitable other streams.
- **Cooling tower purge** - Where evaporative cooling towers are used, biocides, most frequently chlorine or bromine based, lead to releases of

Point source emissions to water

prescribed substances to both air and water. Timber used in cooling towers is usually treated with CCA (copper sulphate, potassium dichromate, arsenic pentoxide), most of which remains well bound to the timber over its operating life, but initial surface residues can lead to significant levels in the purge water. You should include the requirement for controlled washing at the treatment site in your specification for treated timber.

Indicative BAT

You should where appropriate:

Oil storage

1. Fit a high-level alarm to oil tanks.
2. Drain decanted water from oil storage tanks and storm water from bunded areas to a water treatment plant, or direct it to an appropriate disposal facility. You should deal with liquid effluents generated during periodic tank cleaning in a similar way.
3. Use oil removal facilities such as partition chambers or plate separators for water contaminated with oil.

Coal storage

4. Where there is a significant risk of pollution of water or groundwater, you should collect and treat leachate.

De-ionisation effluent

5. Neutralise water de-ionisation plant regeneration effluent before discharge.

Process water (e.g. wet scrubbing)

6. Chemically treat, neutralise and settle the effluent from wet scrubbing before discharge.
7. Quantify organics, including dioxins, furans and PAHs in the treated effluent. At low levels they are normally most effectively treated in a biological plant, usually by the sewerage undertaker.
8. Discharge volumes for sea water scrubbing make most treatment impracticable. Since contaminants are likely to be present in very low concentrations, focus your effort on minimising mass releases where practicable.

Ash handling

9. Handle ashes in a solid state and not as slurry. Hydraulic transport of ashes produces a wastewater stream that is likely to contain metal salts and organic compounds. If there is a market for the ash, you should not use a handling technique that will prevent its re-use.

Cleaning liquids

10. Neutralise or treat wash waters and cleaning-out solutions to produce an acceptable waste before discharge or disposal.
11. Boiler cleaning wastes require appropriate disposal.

Point source emissions to air

Site drainage including rainwater

12. Use an efficient oil/water separation/interceptor system. Further treatment may be required to remove dissolved hydrocarbons.
13. Direct discharge to controlled waters will only be allowed where discharges will meet discharge requirements under all conditions.

Waste water treatment

14. On-site wastewater treatment plant effluent must meet discharge standards.

Cooling tower purge

15. Optimise the dosing regime for biocides in evaporative cooling towers to minimise their use.
16. Chemically treating the main cooling water circuit may allow reduced use of biocides. Do not release accidental overdoses of biocides into the environment.

Thermal plumes

17. In terms of the overall energy efficiency of an installation, the use of once-through systems is an appropriate measure. It may be acceptable to use water from a river or an estuary for once-through cooling, provided that:
    - fish can still migrate through the extended heat plume in the receiving water
    - the cooling water intake minimises fish entrainment
    - heat load does not interfere with other users of the receiving surface water.

3.2 Point source emissions to air

For further information concerning the regulatory framework applicable to large coal and oil fired power stations in England and Wales, refer to “Controls on Releases of Oxides of Sulphur and Nitrogen from Coal and Oil Fired Power Stations” at: http://www.environment-agency.gov.uk/business/444304/444367/972464/?version=1&lang=_e.

NOx control

Primary measures for NOx control

The most important oxides of nitrogen with respect to releases from combustion processes are nitric oxide (NO), nitrogen dioxide (NO_2) (i.e. NOx) and nitrous oxide (N_2O). Nitric oxide forms over 95% of the total NOx in emissions from most types of combustion plant. Higher proportions of NO_2 can be present in exhaust gases from gas turbines particularly modern gas turbines with dry low NOx burner

Point source emissions to air

technology. Atmospheric fluidised bed operations produce higher levels of nitrous oxide than other types of combustion plant.

There are three recognised NOx formation mechanisms:

- "fuel NOx" by conversion of chemically bound nitrogen in the fuel
- "thermal NOx " by fixation of nitrogen in the combustion air
- "prompt NOx " by a mechanism in which molecular nitrogen is converted to NO via intermediate products in the early phase of the flame front with hydrocarbons participating in the reactions.

The first two mechanisms are the only ones of major importance in most combustion plants.

Fuel NOx formation depends on the oxygen level in the vicinity of the flame. Reducing oxygen levels reduces fuel NOx. Fuel NOx is most important in coal fired and biomass fired combustion systems, as these fuels have a higher fuel N content.

Thermal NOx formation requires temperatures greater than 1000°C. Reducing peak temperatures reduces thermal NOx formation. The thermal NOx formation route is the most important source of NOx in emissions from oil and gas fired plant.

Baseline NOx emissions from unabated internal combustion engines vary with engine size and speed (RPM). Larger, lower speed engines will produce more NOx than smaller high-speed engines. Similarly NOx emissions from unabated gas turbines are generally a function of engine load, combustor temperature and size.

Applying combustion modifications is limited by operational and fuel specific parameters, that influence the safe operation of plant, such as:

- ignition stability at the burner
- change in flame shape
- problems of corrosion and erosion
- incomplete burnout of the fuel
- increase in CO emissions
- change in flue gas temperature
- changes in the water-steam circuits.

As a result of the likely changes in one or more of these parameters, the suitability and choice of a primary measure and the resulting effects may not be directly transferable from one type of plant to another.

Large boilers and furnaces

Combustion modification techniques include:

NOx control by operational adjustments

Reducing the level of excess air can reduce NOx emissions, but carbon monoxide and carbon in ash levels must also be controlled. Particulate emissions may also increase and thermal efficiency may be affected. All new plant should be

Point source emissions to air

designed to take account of these characteristics.

In large multiple burner boilers, the upper burners may be used to supply air only. This is not as effective as purpose designed over fire air (OFA) systems. This technique is most suitable for gas and oil-fired boilers.

If you preheat your combustion air (up to 300°C), reducing the level of air preheat may reduce NOx emissions but at the expense of a reduction in thermal efficiency.

Low NOx burners

Low NOx burners are effective in reducing NOx emissions, but may cause increased emissions of carbon monoxide to air, and a higher level of carbon in the ash. You should use them in all new plant. Retrofitting low NOx burners should be considered for all plant, but sometimes the modifications required make it impossible. Low NOx burners are highly effective for gas firing but there is a tendency to generate particulates when firing heavy fuel oil.

Over-fire air (OFA)

This technique involves introducing air above the primary combustion zone in a boiler. The technique is best used in conjunction with low NOx burners and may be applied to small and large boilers. 15-25% of the total combustion air can be supplied as OFA. The reduction of NOx emissions is variable, depending on boiler type and design and the method of OFA application. The use of this technique may result in increases in carbon monoxide and unburnt carbon emissions. Carbon in ash levels must be controlled.

Flue gas recirculation (FGR)

Recirculation of flue gas dilutes the combustion air, lowering peak flame temperatures and reducing the thermal NOx produced. This technique is useful for gas and oil firing (distillate in particular), but is less effective for coal firing. Particulate emissions may increase with heavy fuel oil. This technique should be considered in the design of boilers. Space requirements may prevent its application to smaller designs. Retrofitting to some types of existing plant may be possible.

Reburn

This technique controls NOx emissions by injecting part of the fuel input at a level above the main combustion zone in the boiler. In this fuel rich region the NOx produced in the main combustion zone is reduced. Up to 20% of fuel may be introduced this way and the fuel need not be the same as the primary fuel. Thus gas or oil might be the reburn fuel for a coal-fired boiler. This technique can be applied to new and existing boilers and in combination with low NOx burners. The higher the initial concentration of NOx, the more efficient reburn is at reducing NOx emission levels.

For smaller scale combustion plant, for example plant regulated only as a result of

Point source emissions to air

aggregation or small (<100MW(th)) single units, the use of combustion modifications may be sufficient in the consideration of appropriate measures for the control of oxides of nitrogen emissions.

Pressurised fluidised beds

Pressurised fluidised bed combustion (PFBC) plants are now available up to 400 MW(th).Emissions of NOx are inherently lower than with conventional fuel systems. If required, ammonia can be directly injected (a form of SNCR) into the furnace to reduce NOx further, without using add-on back-end catalysts (i.e. SCR). SOx levels are also inherently low due to the use of sorbent (limestone or dolomite), which also helps form the fluidised bed.

Recent developments in pressurized fluidized bed combustion (PFBC) technology include:

Freeboard firing – injecting a small quantity of oil into the freeboard at part load increases the plant's efficiency and also maintains the conditions for selective non-catalytic NOx reduction close to those valid at full load conditions.

Fly ash recirculation – improves SO_2 emission reductions for a given quantity of sorbent feed. Improvements in combustion efficiency can also be achieved. Thermal NO*x* is not produced. SO_2 emissions are controlled by feeding a sorbent (limestone or dolomite) into the fluidized bed. Elevated pressures in the PFBC improve SO_2 capture.

Turbine engines

The use of combined cycle gas turbine (CCGT) plant is the appropriate measure for new gas turbine installations. Dry low NOx combustion is preferred to wet low NOx combustion for new plant. Low emission combustors can be retrofitted to some existing gas turbines, but it may be more economical to replace others with new higher-efficiency, lower-emissions models. Additional NOx formed by supplementary firing in the exhaust using a well-designed and adjusted burner can be much less than would be expected by firing in air. This is often used in CHP schemes to vary the ratio of heat to power produced. It has a high incremental thermal efficiency and low environmental impact. Very low NOx emissions are not achieved with auxiliary firing when the gas turbine is not running.

Reciprocating engines

Note that this technology is developing rapidly. You should ensure that you consider the latest developments when planning the installation of new plant.

The principal technique used to reduce NOx emissions is lean burn technology, where the fuel content of the charge is less than stoichiometric. This reduces local temperatures by dilution and ensures there is ample oxygen for good hydrocarbon conversion.

Low NOx emissions from both SI and CI engines can also be achieved by combustion modification. Applying the

Point source emissions to air

techniques listed below is limited by engine design, plant operation and certain fuel parameters. The suitability and choice of a primary measure may not be directly transferable from one engine to another (or between SI – CI engines):

- reduction of charge temperature by the addition of water (CI Engines). This reduces NOx, but is impractical in most circumstances
- tuning for NOx (ignition timing). Reducing the timing angle reduces NOx emissions but it also reduces engine efficiency and increases levels of CO and VOCs
- the use of SCR for gas fuelled SI engines. SI engine exhausts are prone to rapid fluctuations in pressure, which can destroy the SCR catalyst
- fuel/air mixing improvements (CI engines.) This is generally only available on new engines, although multiple discharge injectors can be retrofitted to existing engines
- reduction of air manifold temperature. Increased after-cooling may reduce the temperature of the air charged into the cylinders and reduce NOx levels. This technique should be applicable to both existing and new engines
- exhaust Gas Recirculation (EGR). Recycling exhaust gas into the air inlet feeds more inert mixture into the engine and reduces NOx emission. This method of NOx reduction is not recommended for lean burn engines.

All the above techniques except lean burn engines have the drawbacks of reduced efficiency and increased emissions of CO and VOCs. Effective control of combustion conditions is essential if they are used.

Plaster processes

In installations manufacturing plaster from gypsum, the combustion gas stream is intentionally diluted with additional air in order to provide, for example, a transport medium for dried and calcined material and a heat transfer medium, which interacts directly with individual particles. For effective process performance the oxygen content of exhaust gases often approaches ambient levels. For such installations, the excess air should be minimised.

Secondary abatement measures to control NOx

End-of-pipe flue gas technologies to reduce NOx emissions rely on the injection of ammonia, urea or other compounds to react with the NOx in the flue gas and reduce it to molecular nitrogen. They can be divided into:

- selective catalytic reduction (SCR)
- selective non catalytic reduction (SNCR).

Selective catalytic reduction (SCR)

SCR reduces NO and NO_2 to N_2 with the addition of ammonia or urea solution in the

Point source emissions to air

presence of a catalyst at 300-400°C. SCR plant can be operated at various locations in the flue gas stream. It may also be positioned after exhaust gas de-sulphurisation, although this arrangement would normally require an exhaust gas reheating stage, which may take up as much as 2% of the electric capacity. This measure typically removes between 80 and 90% of the NOx.

SCR is used on combustion plants from <50 MW(th) to 1000 MW(th). The use of SCR for gas turbines can achieve ultra low NOx emissions (<10 mg/m^3 at 15% O_2). Catalytic combustion is in commercial development for some types of gas turbine.

The use of SCR requires the storage of liquid ammonia or ammonia solution.

Selective non-catalytic reduction (SNCR)

SNCR reduces NOx emissions by chemically reducing them to nitrogen and water through the injection of NH_2-X compounds into the furnace. SNCR is operated without a catalyst at a temperature of 850 to 1100°C. The temperature window and residence time can strongly influence the reagent used (ammonia or urea). Ammonia tends to give rise to lower nitrous oxide formation but urea may be more effective over a slightly larger temperature window and is easier to handle. Abatement efficiencies of up to 80% have been claimed although efficiencies of 30-50% are more typical.

SNCR also requires a sufficient retention time for the injected reagents to react with NO. Reagent distribution/injection must be optimized and computational fluid dynamics modelling may be useful, and essential for all new plant.

Forms of SNCR have been successfully used at lower temperatures in both CFBC and PFBC systems.

Point source emissions to air

Indicative BAT

You should where appropriate:

1. Control emissions of NOx by a combination of the following, as applicable:
   - combustion control systems
   - combustion temperature reduction
   - low NOx burners
   - over fire air (OFA)
   - flue/exhaust gas recycling
   - reburn
   - selective catalytic reduction (SCR)
   - selective non catalytic reduction (SNCR).
2. Use low NOx burners for coal- and oil-fired plant.
3. Use OFA or equivalent for existing coal-fired plant above 100 MWth).
4. Use dry low NOx burners in new natural gas-fired gas turbines. For natural gas-fired gas turbines, use water/steam injection, or convert to dry low NOx burning.
5. Where air quality standards or other environmental standards must be met, you must use SCR or SNCR for smaller plant (<100 MW).
6. For new coal and oil-fired plant above 100MW, use SCR or primary measures to achieve equivalent NOx levels.
7. Only combustion optimisation and SCR are feasible on >500MW PF plant firing low volatile coal. In these cases you need SCR for new plant. You need a site specific assessment for existing plant.

SOx control

Fuel Selection

The source of sulphur in emissions to air from combustion processes is the fuel. During combustion the major oxide of sulphur produced is sulphur dioxide (SO_2). Sulphur trioxide is adsorbed and reacts with ash particles in the flue gases. It is more likely to pose a problem with low ash fuels (e.g. fuel oils) and its presence is an important contributing factor in acid smutting. Measures used to control SOx will also result in lower emissions of hydrogen chloride and hydrogen fluoride.

Point source emissions to air

Fuel selection needs to consider a wide range of quality parameters and is a complex issue.

For smaller scale combustion plant, use of low sulphur fuels (ie less than 1.2 % S) may be sufficient in the consideration of BAT for control of oxides of sulphur emissions.

Coal sulphur content varies widely (range 0.1-3.5%). If coal is the selected fuel, flue gas desulphurisation (or a technique that delivers equivalent emissions) is required. Where life or size of the plant precludes FGD as BAT, then low sulphur coals should be used.

For fuel oils, the Sulphur Content of Liquid Fuels (SCOLF) Regulations set limitations on the sulphur content of liquid fuels. A similar approach should be adopted to that used for coal fired plant.

Natural gas that meets the standard for acceptance into the National Transmission System is considered to be a sulphur free fuel. Natural gas that does not meet this standard, and industrial gases (e.g. some refinery gas and gases from gasification plants) may contain sulphur compounds and may require desulphurisation.

The sulphur content of biofuels can range widely, dependent upon the fuel used. For example straw and barley crops can contain between 0.2 and 0.7% sulphur whilst concentrations in willow are expected to be at round 0.06%

For coal fired plant:

Coal washing is well developed. Most techniques involve crushing coal to fine particle sizes and then separating pyrites and ash content from coal. Depending on the pyrites content, up to 50% of the original coal sulphur may be removed. However, extra energy is consumed, a water waste stream is produced and solids waste will require disposal.

For industrial gas fired plant:

Gas cleaning reduces the sulphur content of raw gas streams. Sulphur compounds in the raw fuel gas may be recovered as elemental sulphur by additional treatment. Where gasification is used as an alternative to the direct combustion of coal, oil and oil emulsion fuels, it should be possible to remove about 99% of the sulphur present in the original feedstock.

In-furnace sulphur control

Emissions of sulphur dioxide from combustion plant can be reduced using in-furnace injection of sorbents. Fluidised bed combustion (FBC) techniques are suited to this technique. In FBCs, between 10-15% of sulphur is retained in the ash as a result of reaction with calcium carbonate naturally present. Adding crushed sorbent material (e.g. limestone) to the bed may increase sulphur retention in the ash. Wider environmental considerations include the use of limestone and its disposal, and possible uses of the combustor bottom ash and the fly ash streams.

Point source emissions to air

Dry sorbent injection may also be used with pulverised fuel furnaces, however the efficiency of SO_2 removal tends to be lower than with some other wet and dry FGD techniques.

Sulphur dioxide abatement

For large coal-fired plant, end-of-pipe flue gas desulphurisation (FGD), or equivalent techniques are considered appropriate measures. Removal efficiency is “the ratio of sulphur not emitted over a given period to the sulphur in the fuel over the same period”; or, the “Rate of desulphurisation”. The given period will be when the FGD plant is ‘Available’ for use and excludes start up and shutdown periods.

Wet limestone scrubbing

Sulphur dioxide removal is currently about 90-92% at existing FGD plant in the UK (500-600 Mwe), depending on coal sulphur content. The by-product is gypsum. Hydrogen chloride in the flue gas is captured in the scrubber liquor and is purged in the wastewater stream. Sulphur dioxide removal may be increased up to 92-98% (BREF reference), but the buffers used to assist in controlling the chemistry of the process may increase problems with waste-water treatment from scrubbing plant.

This technique represents an appropriate measure for large coal-fired combustion plants above 100 MWth scale and large CI engines using high sulphur residual/fuel oils, which have the potential for high sulphur dioxide emissions. If the facility only operates for a limited period this may change the cost benefit equation and make wet limestone scrubbing uneconomic.

Sea water scrubbing

This technique is considered an appropriate measure for large combustion plants situated on the coast. Up to 98% sulphur dioxide removal is possible. The reheat system may limit efficiency if a bypass is required. Localised effects of the additional sulphate, chloride, heavy metals and elevated temperatures in the discharge must be addressed.

Spray dry scrubbing

This has been used on coal and oil fired systems. 70-95% sulphur dioxide removal is possible. Hot flue gases dry the wet scrubbing medium, which results in a dry residue and an aqueous waste steam is not produced.

Dry sorbent scrubbing

A solid residue is produced which can be used. 80-95% sulphur dioxide removal is possible depending on the process and the quantity of sorbent used. The sorbent may be lime, limestone or other material. A fabric filter is needed to remove alkaline dusts. The filter coated with alkaline dust enhances the scrubbing effect.

Point source emissions to air

Indicative BAT

You should where appropriate:

1. Use low sulphur fuels as a primary measure.
2. For large coal or oil-fired plant, use wet limestone scrubbing or seawater scrubbing for flue gas desulphurisation (FGD).
3. Consider dry sorbent injection for pulverised and liquid fuel furnaces which are too small to justify FGD.
4. For fluidised bed combustors, consider in-bed sulphur capture.
5. Consider IGCC for new large-scale solid and liquid fuel fired plant.

Particulate matter control

Solid and liquid fuel fired plants emit particulate matter. Gas fired plant using natural gas will not generally require particulate control. Some industrial gases contain particulates and should be filtered on production or, if that is not possible, before combustion.

Abating particulate matter, especially the finer fractions, is a significant method of controlling the release of heavy metals, dioxins and polynuclear aromatic hydrocarbons (PAHs).

Where particulate abatement is required, the options include:

- electrostatic precipitators (EPs)
- fabric filters
- ceramic filters
- wet scrubbers
- cyclones

For Compression Ignition (CI) engines, particulate removal efficiency is very dependent upon fuel quality. For many CI engine sites particulate abatement may not be required. New CI engines should be capable of achieving the given unabated release levels.

Electrostatic precipitators

Electrostatic precipitators located downstream of FGD can consistently achieve levels below 25 mg/m^3. Where FGD is not fitted, levels of 50mg/m^3 should be achieved. Electrostatic precipitators are used in both solid and liquid fuelled combustion plants and are available for small and large-scale plant.

Fabric Filters

Bag (fabric) filters when correctly operated and maintained provide reliable abatement to below 10mg/m^3 and are likely to be the appropriate measure for many

Point source emissions to air

applications. They cannot generally be used at temperatures over 250°C.

In oil-fired plant, using a pre-coat of lime or ash on the bags adsorbs any oil carryover. Bags in oil fired plant need to be cleaned less often than with other fuels and fresh coating material must be injected to coincide with cleaning cycles. Using filters in this way must also be done in conjunction with maintaining good combustion control.

Good temperature control is required to prevent thermal damage to bags and blinding by the condensation of moisture

Ceramic filters

Ceramic filters are available for small combustion plant and are being developed for larger plant. They can normally achieve reliable levels below 10 mg/m^3 and have low maintenance requirements. Ceramic filters are able to withstand high temperatures around 800-900°C. Operating temperatures are usually limited by the housing rather than the filter media.

Indicative BAT

1. For coal and oil-fired plant above 100 MWth, electrostatic precipitators (EP) are required. At smaller scale plant, other methods may be acceptable to meet emission limits.
2. For 'opted in' [2] plant FGD is an appropriate measure, and therefore particulate abatement is FGD + EP.
3. For large (>100 MW) existing plant and where FGD is not required (not 'opted in') EP is an appropriate measure.
4. Where low sulphur fuel is used with EPs, use sulphur trioxide injection to improve particulate control.

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[2] 'Opted in' plant have to comply with the requirements of the Large Combustion Plants Directive.

Point source emissions to air

Control of CO_2, CO and volatile organic compounds (VOC)

All measures to reduce fuel use will also reduce CO_2 emissions. Selecting raw materials with low organic matter content and fuel with a low ratio of carbon content to calorific value reduces CO_2 emissions.

Elevated CO and VOC emissions indicate poorly controlled combustion and may also indicate higher releases of other pollutants. Good combustion conditions are required to minimize releases.

Where necessary, the use of catalytic oxidation in the exhaust gas stream will reduce carbon monoxide emissions to less than 100 mg/m^3.

Other releases

Metals and their compounds

The largest proportion of metals and compounds released to air are in the particulate phase, except for mercury and boron, which are released in the vapour phase. Controlling particulate levels (see above) and selecting residual fuel oils with a low ash content will control levels of most metals. Vapour phase mercury and other heavy metals will be partially removed from flue gases during FGD when using a wet scrubbing system.

Halogens

Hydrogen chloride and hydrogen fluoride are produced during the combustion of coal and oil and some biofuels and waste derived fuels. Techniques used for abating sulphur dioxide will also reduce these gases. UK coal contains 0.1 - 0.6% chloride and so emissions of hydrogen chloride will be significant from larger unabated combustion plant.

Polycyclic aromatic hydrocarbons (PAHs)

Total PAH (unspecified) emissions for large coal and oil fired combustion plant are of the order of 10-100 ng/m^3 in the flue gas. Some PAH is associated with particles, so abating particulates (see above) will reduce emissions of PAHs, although the ash and dust will be contaminated.

Dioxins

Dioxins can potentially be formed by the combustion of any carbon containing fuel in the presence of trace quantities of chloride. Dioxins are usually present in both the particulate and vapour phases and accordingly measures to reduce particulate matter emissions will also significantly reduce emissions of these compounds. FGD systems can enhance dioxin removal as can some SCR systems employed for NOx reduction. These systems should not be relied upon as primary measures to abate dioxins, which should be at concentrations below or close to the limits of current measurement and analysis techniques.

Fugitive emissions

3.3 Fugitive emissions

On many installations fugitive or diffuse emissions may be significant.

Coal, limestone and other solid raw materials may create a dust problem during receipt and subsequent handling and processing operations. Particulate emissions to air should be minimised.

Liquid feedstocks should be stored in roofed tanks. Venting arrangements will depend on the nature of the feedstock, its vapour pressure and composition. The size and number of tanks will depend on whether the oil is the main or standby fuel. Alternatively, at larger sites, oil may be supplied from nearby refinery sites by pipeline. Oil and oil emulsion storage facilities require heating plant to reduce the viscosity of the fuels. Releases will include volatile organic compounds (VOC's) to air, oil spills from storage and transfer operations and sludge from tanks.

Gaseous fuels are supplied direct by pipeline. Where gas is used as a fuel, local compression facilities may be required in order to inject sufficient fuel. Releases of gaseous fuels can arise from controlled venting during maintenance and purging of the fuel system.

Indicative BAT

1. Windbreaks should be created by natural terrain, banks of earth or planting of long grass and evergreen trees in open areas. This has aesthetic benefits and such vegetation is able to capture and absorb dust without suffering long-term harm. Hydro seeding should be used to rapidly establish vegetation on waste tips, slag heaps or other apparently infertile ground.
2. Where materials are delivered by sea and dust releases could be significant, use self-discharge vessels or enclosed continuous unloaders.
3. Minimise dust generated by grab-type ship unloaders by ensuring adequate moisture content of the material as delivered, minimising drop heights and using water sprays or atomised mist at the mouth of the ship unloader hopper.
4. **Fugitive emissions** from fly ash should be prevented by dust suppression, or by enclosing its handling and storage.
5. Intercept rainwater run off from open areas, especially coal and raw materials stocking areas, and remove the suspended solids by settlement or other techniques. Where there are potentially vulnerable receptors, monitor the quality of the water discharged from the storage and blending areas.
6. Plant used to pre-treat and store raw materials should be totally enclosed, with extraction

and arrestment plant as appropriate, to prevent emissions to atmosphere. For some gasification processes coal is milled to a very fine dust and needs to be handled with an inert gas blanket.

7. Gasifiers should be coal-charged using a double lock system, whereby the gases released from the reactor during charging are contained within the lock hopper. After closure of the charge valve they are routed either to recompression for re-injection into the crude gas stream or to a vent treatment system. Alternatively, a wet feed (slurry) system may be used with comparable features.
8. You should demonstrate that the potential risks of contamination of land by deposition of dust, leachate or run-off are not significant and that you can comply with the requirements of the Groundwater Directive.

3.4 Monitoring

Indicative BAT

1. **Emissions to air**

Many plants in this sector will be subject to the detailed monitoring requirements of Annex VIII of the Large Combustion Plant Directive (LCPD). For plants co-incinerating waste, the provisions of Articles 10, 11 and Annexes II and III of the Waste Incineration Directive (WID) should also apply. The monitoring requirements of the LCPD and WID are considered to represent appropriate measures for this sector. The LCPD requires that:

For existing plant using continuous emission monitors the emission limit values shall be regarded as having been complied with if the evaluation of the results indicates, for operating hours within a calendar year, that:

(a) none of the calendar monthly mean values exceeds the emission limit values; and
(b) in the case of:
  - sulphur dioxide and dust: 97% of all the 48 hourly mean values do not exceed 110% of the emission limit values
  - nitrogen oxides: 95% of all the 48 hourly mean values do not exceed 110% of the emission limit values.

For new plants, emission limit values shall be regarded, for operating hours within a calendar year, as complied with if:

(a) no validated daily average value exceeds the relevant figures set out in part B of Annexes III to VII, and

Monitoring

(b) 95% of all the validated hourly average values over the year do not exceed 200% of the relevant figures set out in part B of Annexes III to VII.

For both existing and new plants, start-up and shut-down periods shall be disregarded.

Installations that do not fall within the scope of WID or LCPD should meet the benchmark standards except where you can clearly demonstrate that this is not the appropriate measure.

We may require you to monitor and report releases more frequently than required by WID or LCPD where it is considered appropriate to do so.

You should process the readouts from continuous emission monitors using software that reports monitoring compliance, to enable direct comparison with the emission limit values specified in relevant European legislation and in this guidance.

In order to relate emission concentrations to mass releases, you will need to measure or otherwise determine the stack gas flow rate. In order to relate measurements to reference conditions, you will need to determine temperature and pressure. Determination of oxygen or water vapour content may also be required. All such measurements should be recorded.

2. Emissions to water and sewer

For combustion plants co-incinerating waste and operating air pollution control equipment with an aqueous discharge, you should comply with Article 8 and Annexes III and IV of the Waste Incineration Directive (WID).

Environmental monitoring (beyond installation)

Specific environmental monitoring requirements which may be required are:

To air:

Where there is a significant public concern/record of complaint:

- you should keep 24 hour time/date coded CCTV/video recordings of chimney stack emissions
- you should record wind speed and direction data to help with complaint investigation.

To water:

- effluent treatment plant discharges to controlled waters
- cooling water discharges

To land:

Monitoring surveys may be needed where sensitive soil systems or terrestrial ecosystems are at risk from deposition of air borne pollutants or direct impacts of any on-site operations.

Monitoring

Process variables

You should consider monitoring for process variables that may affect the environment. For example:

- differential pressure across abatement equipment which can indicate removal efficiency, filter failures, etc.
- solid and liquid fuel fired plants - fuel feedstock should be sampled and analysed at a frequency and manner appropriate to the type of plant concerned
- potential difference across EP plates
- reagent injection or feed rates.

4

Annexes

Annex 1 Emission benchmarks

Annex 2 Other relevant guidance and abbreviations

Annex 3 Regulatory information

Annex 1-Emission benchmarks

4. Annexes

Annex 1- Emission benchmarks

The emissions quoted below are daily averages based upon continuous monitoring during the period of operation.

New plants

- No daily average value exceeds the benchmark value.
- 95% of all hourly averages over a defined period, e.g. a calendar year do not exceed 200% of the benchmark value.

Retrofit plant

- No monthly average value (where defined in table 3.1) exceeds the benchmark value.
- For SO_2 and dust, 97% of the 48 hour average values do not exceed 110% of the benchmark value.
- For NOx, 95% of the 48 hour average values do not exceed 110% of the benchmark value.

Where spot tests are employed:

- It may be necessary to set periodic limits taking account of sampling times practical for the spot test method involved.
- Where the continuous and spot test sampling periods are compatible, the mean of three consecutive tests taken during a calendar year shall not exceed the relevant continuous monitoring benchmark value by more than 10%.

Processes, which come under the provisions of the Large Combustion Plant Directive or the Waste Incineration Directive, will also need to address the specific requirements of these directives.

Annex 1-Emission benchmarks

Release values shown are for consolidated but not agglomerated units and NOx releases values under LCPD are ‘not opted out’ >2000 hr 5 yr rolling average.

Reference conditions for releases to air

The reference conditions of substances in releases to air from point-sources are:

- For combustion gases:
    - dry
    - temperature 273K (0°C)
    - pressure 101.3kPa (1 atmosphere)
    - oxygen content
        - 3% v/v, dry for liquid and gaseous fuels burned at large boilers and furnaces
        - 15% v/v, dry for liquid and gaseous fuels burned at CI engines and gas turbines
        - 6% v/v, dry for solid fuels burned at large boilers and furnaces.
- For non-combustion gases:
    - temperature 273K (0°C)
    - pressure 101.3kPa
    - no correction for water vapour or oxygen content.

To convert measured values to reference conditions, see **Monitoring Guidance**[3].

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[3] Environment Agency Technical Guidance Notes M1 and M2 provide extensive guidance on the monitoring of stack emissions to air. The conversion referred to is given in TGN M2.

Annex 1-Emission benchmarks

Table 1.1 - Summary of achievable releases to air (normal font- daily averages, underlined font- monthly averages).

Note 1 where FGD used

Note 2 Low sulphur coal will produce typically 100mg/m^3 per 0.1% Cl in coal. Duct Sorbent Injection will reduce this by up to 90%

Note 3 Where straw or other higher Cl containing biomass material are used, HCl concentrations may be up to 300mg/m^3

Note 4 Upper end of range applies where higher moisture content biomass is BAT.

Fuels and processes	**Size MW$_{th}$**	**Process**	**Ref % O_2**	**Achievable concentrations, mgm^3, dry at 0°C, 101.3kPa (at ref O_2)**					
				PM	**SO_2**	**NO_x**	**N_2O**	**CO**	**HCl**
Coal	50-100	New Grates/PC	6	20	400	300	10	150	10 Note 1,2
		New CFBC and PFBC		20	400	300	30-120	150	30
		New BFBC		20	400	300	30-120	100	5
		Retrofit PC	6	100	1300	600	2-10	400	400 Note 2
		Retrofit CFBC and PFBC		100	1300	600	30-120	150	30
		Retrofit BFBC		100	1300	600	30-120	100	1 - 5
	100-300	New PC	6	20	200	200	2-10	150	10 Note 1,2

Annex 1-Emission benchmarks

		New CFBC and PFBC		20	200	200	30-120	150	30
		New BFBC		20	200	200	30-120	100	1-5
		Retrofit PC		100	400	600	2-10	400	400 Note 2
		Retrofit CFBC and PFBC		100	400	600	30-120	100	30
		Retrofit BFBC		100	400	600	30-120	100	1-5
	>300	New PC	6	10	150	150	2-10	150	10
		New CFBC and PFBC		10	200	200	30-120	150	30
		New BFBC		10	200	150	30-120	100	1-5
		Retrofit PC with FGD & OFA	6	25	400	500	2-10	400	0 Note 1
		…with OFA		50	2,000	500	2-10	400	400 Note 2
		Retrofit CFBC and PFBC		100-50	100-200	500	30-120	100	30
		Retrofit BFBC		100-50	1200-400	500	30-120	100	1-5
	>500	Retrofit PC with FGD & OFA	6	25	400	500		400	40 Note 1
		…with OFA		50	2000	500		400	400 Note 2

Annex 1-Emission benchmarks

Table 1.1 continued

Fuels and processes	**Size MW_{th}**	**Process**	**Ref % O_2**	**Achievable concentrations, mg/m^3, dry at 0°C, 101.3kPa (at ref O_2)**					
				PM	**SO_2**	**NO_x**	**N_2O**	**CO**	**HCl**
Biomass	50-100	New PF/Grates New FBC	6	20	300	300 250		100-250 Note 4 100-150 Note 4	25 Note 3
		Retrofit PF/Grates Retrofit FBC	6	50	300	300		100-250 Note 4	25 Note 3
		Retrofit PF/Grates Retrofit FBC	6	50	300	300		100-250 Note 4 100-150 Note 4	25 Note 3
	>300	New PF/Grates New FBC	6	20	200	150		100-250 Note 4 100-150 Note 4	25 Note 3
		Retrofit PF/Grates Retrofit FBC	6	50	200	200		100-250 Note 4 100-150 Note 4	25 Note 3

Annex 1-Emission benchmarks

Table 1.1 continued

Fuels and processes	Size MW_{th}	Process	Ref % O_2	Achievable concentrations, mg/m^3, dry at 0°C, 101.3kPa (at ref O_2)					
				PM	SO_2	NO_x	N_2O	CO	HCl
Liquid Fuels	50-100	New	3	15	350 (175 post 2008)	300		150	1-5
		Retrofit 1%S 1%S +DSI	3	50	1700 685	450		30-50	1-5
	100-300	New	3	15	200	150		150	1-5
		Retrofit 1%S 1%S +DSI	3	50	1700 400	450		30-50	1-5
	>300	New	3	15	150	100		150	1-5
		Retrofit opt out	3	50	1700	1400		30-50	1-5

Annex 1-Emission benchmarks

		Opt in			400	450-400 (300-500MW)			
		Engines CI	15	50	112 66 from 2008	150		150	
		Gas Turbines	15		112	125		100	
					(66 from 2008)				

Annex 1-Emission benchmarks

Table 1.1 continued

Fuels and processes	**Size**	**Process**	**Ref % O_2**	**Achievable concentrations, mg/m^3, dry at 0°C, 101.3kPa (at ref O_2)**					
				PM	**SO_2**	**NO_x**	**N_2O**	**CO**	**HCl**
Natural gas		New Gas Turbines (incl CCGT)	15	5	10	20-50		100	
		Existing GTs(inc CCGT)DLN Water or Steam injection	15	5	10	75 110		100	
		Engines CI(dual Fuel) SCR	15	20	50	100		450	
		Engines CI(dual fuel) Lean burn	15	20	50	150		150	
		Engines SI SCR	5			250		400	

Annex 1-Emission benchmarks

		Engines SI Lean Burn pre 2005	5			250 500		400 1000	
		New Boilers (<100MW / >100MW)	3	5	10	150/100		30-50	
		Existing Boilers (<500MW / >500MW)	3	5	10	300/200		50	

Annex 1-Emission benchmarks

Table 1.1 continued

Fuels and processes	**Size**	**Process**	**Ref % O_2**	**Achievable concentrations, mg/m^3, dry at 0°C, 101.3kPa (at ref O_2)**					
				PM	**SO_2**	**NO_x**	**N_2O**	**CO**	**HCl**
Industrial gas		All combustion plant	3 or 15	Appropriate measure is gas cleaning to remove fuel S and fuel PM	Appropriate measure is gas cleaning to remove fuel S and fuel PM				
Smokeless Fuels									
Combustor/Incinerator/ Battery/Boiler Flue Gases				25		300		150	
Dryer Vents				25		300			
Battery Abatement				25					

Annex 1-Emission benchmarks

Dryer Vents				25		300			
Screen Abatement				25					
Coal/oil liquor handling				25					
Carbon black									
Boiler/CHP flue gases			10	25	2300	500		150	
Dryer Flue Gases			10	25	2300	500		150	
Process/Purge/ dust filters			10	10					
Other Processes		(Corrected to 3% O_2 liquid & gas fuels, 6% O_2 solid fuels)							
Combustion process release points						300		150	

Annex 1-Emission benchmarks

Table 1.1 continued

Fuels and processes	**Size**	**Process**	**Ref % O_2**	**Achievable concentrations, mg/m^3, dry at 0°C, 101.3kPa (at ref O_2)**					
				PM	**SO_2**	**NOx**	**N_2O**	**CO**	**HCl**
Gasification		Liquid and gas	3% v/v	Appropriate measure is gas cleaning to remove fuel S and fuel PM 10-25	Appropriate measure is desulphurisation to remove S 97-99.8%	Use of low NOx technology in heating burners 200		200	
		Solid fuels	6% v/v						
		GT oper'n	15% v/v						
GCC			15%	1mg/MJ	1	45	20		

General Note Releases values shown are for consolidated but not agglomerated units and NOx releases values under LCPD are 'not opted out' >2000 hr 5 yr rolling average.

Annex 2-Other relevant guidance and abbreviations

Annex 2- Other relevant guidance and abbreviations

For a full list of available Technical Guidance and other relevant guidance see Appendix A of GTBR (see http://publications.environment-agency.gov.uk/pdf/GEHO0908BOTD-e-e.pdf?lang=_e).

In addition to the guidance in GTBR the following guidance is relevant to this sector:

1. The Categorisation of Volatile Organic Compounds, 1995 HMIP Report No DOE/HMIP/RR/95/009
2. BREF on Waste Water and Waste Gas Treatment Industry http://www.jrc.es/pub/english.cgi/0/733169 or http://eippcb.jrc.es
3. LFTGN 6 Guidance on gas treatment technologies for Landfill Gas Engines http://www.environment-agency.gov.uk/commondata/acrobat/lftgn06_treatment_936556.pdf

Abbreviations

BAT	Best Available Techniques
BOD	Biochemical Oxygen Demand
BREF	BAT Reference Document
CEM	Continuous Emissions Monitoring
CHP	Combined heat and power plant
COD	Chemical Oxygen Demand
ELV	Emission Limit Value
EMS	Environmental Management System
EQS	Environmental Quality Standard
ETP	Effluent treatment plant
FOG	Fat Oil Grease
ITEQ	International Toxicity Equivalents
MCERTS	Monitoring Certification Scheme
NIEHS	Northern Ireland Environment and Heritage Service
SAC	Special Areas of Conservation
SECp	Specific Energy consumption
SEPA	Scottish Environment Protection Agency
SPA	Special Protection Area
TSS	Suspended solids
TOC	Total Organic Carbon
VOC	Volatile organic compounds

Annex 3-Regulatory information

Annex 3- Regulatory information

Tables 3.1 and 3.2 provide information regarding which part of the regulations apply to your plant.

Note that this table is not applicable in Scotland. Please contact SEPA to discuss combustion plant regulatory issues for Scotland

Table 3.1 Combustion, gasification plus combustion or pyrolysis (where gas is produced) plus combustion

		<0.4MWth	**0.4 - 3MWth**	**3 - 20MWth**	**20 - 50MWth**	**>50MWth**	
Material Processed		See note 1					
Fuel not comprising Waste e.g. coppiced wood		Not regulated under EPR	Not regulated under EPR	Not regulated under EPR	1.1 B(a)	1.1A(1)(a)	WID DOES NOT APPLY
WID Exempt waste e.g. biomass		Not regulated under EPR	1.1 B (c)	1.1A(1)(b)(unless part of a part A(2) or B activity)	1.1A(1)(b)(unless part of a part A(2) or B activity)	1.1A(1)(a)	
Non hazardous	**Incineration (Primary**	5.1A(1)(c) if >= 1t/hr	5.1A(1)(c) if >= 1t/hr	5.1A(1)(c) if >= 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if	WID DOES APPLY

Annex 3-Regulatory information

waste	**purpose is destruction of waste)**	5.1A(2)(a) if < 1t/hr	5.1A(2)(a) if < 1t/hr	5.1A(2)(a) if < 1t/hr		< 1t/hr	
Non hazardous waste	**Co-incineration (Primary purpose is generation of energy)**	5.1A(2)(b)	5.1A(2)(b)	1.1A(1)(b)(unless part of a part A(2)activity)	1.1A(1)(b)(unless part of a part A(2) activity)	1.1A(1)(a)	
Hazardous waste Incineration	**(Primary purpose is destruction of waste)**	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	
Hazardous waste Co-incineration	**(Primary purpose is generation of energy)**	5.1A(1)(b)	5.1A(1)(b)	1.1A(1)(b)	1.1A(1)(b)	1.1A(1)(a)	

Note:1 WID Guidance(ref) excludes certain small waste burners and space heaters or other waste oil burners. In these cases 1.1 B (b) or (c) may apply dependent on individual or aggregated capacity

Annex 3-Regulatory information

PLEASE NOTE This table is not applicable in Scotland. Please contact SEPA to discuss combustion plant regulatory issues for Scotland

Table 3.2 Pyrolysis where gas is not produced

		<0.4MWth	**0.4 - 3MWth**	**3 - 20MWth**	**20 - 50MWth**	**>50MWth**	
Material Processed							
Material not comprising Waste e.g. coppiced wood		1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	WID DOES NOT APPLY
WID Exempt waste e.g. biomass		1.2A(1)(j)	1.2A(1)(j)	1.1A(1)(b)(unless part of a part A(2) or B activity)	1.1A(1)(b)(unless part of a part A(2) or B activity)	1.1A(1)(a)	
Non hazardous waste Incineration	**(Primary purpose is destruction of waste)**	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	WID DOES APPLY

Annex 3-Regulatory information

Non hazardous waste Co-incineration	**(Primary purpose is generation of energy)**	5.1A(2)(b)	5.1A(2)(b)	1.1A(1)(b)(unless part of a part A(2)activity)	1.1A(1)(b)(unless part of a part A(2)activity)	1.1A(1)(a)	
Non hazardous waste	**Material products- No incineration of** any **products** locally or remotely	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	WID DOES NOT APPLY
Hazardous waste	**Incineration (Primary purpose is destruction of waste)**	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	WID DOES APPLY
Hazardous waste	**Co-incineration (Primary purpose is generation of energy)**	5.1(A)1(b)	5.1(A)1(b)	1.1A(1)(b)	1.1A(1)(b)	1.1A(1)(a)	
Hazardous waste	**Material products- No incineration of** any **products** locally or remotely	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	WID DOES NOT APPLY

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