EUROPEAN COMMISSION

Integrated Pollution Prevention and Control

Reference Document on
Best Available Techniques for

Large Combustion Plants

July 2006

This document is one of a series of foreseen documents as below (at the time of writing, not all documents have been drafted):

Reference Document on Best Available Techniques...	**Code**
Large Combustion Plants	LCP
Mineral Oil and Gas Refineries	REF
Production of Iron and Steel	I&S
Ferrous Metals Processing Industry	FMP
Non Ferrous Metals Industries	NFM
Smitheries and Foundries Industry	SF
Surface Treatment of Metals and Plastics	STM
Cement and Lime Manufacturing Industries	CL
Glass Manufacturing Industry	GLS
Ceramic Manufacturing Industry	*CER*
Large Volume Organic Chemical Industry	LVOC
Manufacture of Organic Fine Chemicals	OFC
Production of Polymers	POL
Chlor – Alkali Manufacturing Industry	CAK
Large Volume Inorganic Chemicals - Ammonia, Acids and Fertilisers Industries	LVIC-AAF
Large Volume Inorganic Chemicals - Solid and Others industry	LVIC-S
Production of Speciality Inorganic Chemicals	SIC
Common Waste Water and Waste Gas Treatment/Management Systems in the Chemical Sector	CWW
Waste Treatments Industries	WT
Waste Incineration	WI
Management of Tailings and Waste-Rock in Mining Activities	MTWR
Pulp and Paper Industry	PP
Textiles Industry	TXT
Tanning of Hides and Skins	TAN
Slaughterhouses and Animals By-products Industries	SA
Food, Drink and Milk Industries	FDM
Intensive Rearing of Poultry and Pigs	ILF
Surface Treatment Using Organic Solvents	STS
Industrial Cooling Systems	CV
Emissions from Storage	ESB
Reference Document...	
General Principles of Monitoring	MON
Economics and Cross-Media Effects	ECM
Energy Efficiency Techniques	ENE

EXECUTIVE SUMMARY

The BAT (Best Available Techniques) Reference Document (BREF) entitled 'Large Combustion Plants' reflects an information exchange carried out under Article 16(2) of Council Directive 96/61/EC (IPPC Directive). This Executive Summary describes the main findings, the principal BAT conclusions and the associated emission levels. It can be read and understood as a standalone document but as a summary, it does not present all the complexities of the full BREF text (e.g. full detail of the BAT sections). It is, therefore, not intended as a substitute for the full BREF text as a tool in BAT decision-making and it is strongly recommended to read this summary together with the preface and standard introduction to BAT sections.

More than 60 experts from Member States, industry and environmental NGOs have participated in this information exchange.

Scope
This BREF covers, in general, combustion installations with a rated thermal input exceeding 50 MW. This includes the power generation industry and those industries where 'conventional' (commercially available and specified) fuels are used and where the combustion units are not covered within another sector BREF. Coal, lignite, biomass, peat, liquid and gaseous fuels (including hydrogen and biogas) are regarded as conventional fuels. Incineration of waste is not covered, but co-combustion of waste and recovered fuel in large combustion plants is addressed. The BREF covers not only the combustion unit, but also upstream and downstream activities that are directly associated to the combustion process. Combustion installations which use process-related residues or by-products as fuel, or fuels that cannot be sold as specified fuels on the market as well as combustion processes which is an integrated part of a specific production process are not covered by this BREF.

Submitted Information
A large number of documents, reports and information from Member States, industry, operators and authorities as well as from suppliers of equipment and environmental NGOs have been used to draft the document. Information was further obtained during site visits to different European Member States and by personal communication on selection of technology and on experiences with the application of reduction techniques.

Structure of the document
Electricity (power) and/or heat generation in Europe is a diverse sector. Energy generation is based on a variety of fuels, which can generally be classified by their aggregate state into solid, liquid or gaseous fuels. This document has, therefore, been written vertically, fuel by fuel, but with common aspects and techniques described together in the three introductory chapters.

The European Energy Industry
In the European Union, all available types of energy sources are used for electric and thermal power generation. National fuel resources such as the local or national availability of coal, lignite, biomass, peat, oil and natural gas, largely influence the choice of fuel used for energy generation in each EU Member State. Since 1990, the amount of electric power generated from fossil fuel energy sources increased by about 16 % and demand increased by about 14 %. The amount of electric power generated from renewable energy sources (including hydropower and biomass) shows an above average increase of approximately 20 %.

Combustion plants are operated according to energy demand and requirement, either as large utility plants or as industrial combustion plants providing power (e.g. in the form of electricity, mechanical power), steam, or heat to industrial production processes.

Technologies used

Power generation in general utilises a variety of combustion technologies. For the combustion of solid fuels, pulverised combustion, fluidised bed combustion as well as grate firing are all considered to be BAT under the conditions described in this document. For liquid and gaseous fuels, boilers, engines and gas turbines are BAT under the conditions described in this document.

The choice of system employed at a facility is based on economic, technical, environmental and local considerations, such as the availability of fuels, the operational requirements, market conditions, network requirements. Electricity is mainly generated by producing steam in a boiler fired by the selected fuel and the steam is used to power a turbine which drives a generator to produce electricity. The steam cycle has an inherent efficiency limited by the need to condense the steam after the turbine.

Some liquid and gas fuels can be directly fired to drive turbines with the combustion gas or they can be used in internal combustion engines which can then drive generators. Each technology offers certain advantages to the operator especially in the ability to be operated according to variable power demand.

Environmental Issues

Most combustion installations use fuel and other raw materials taken from the earth's natural resources, converting them into useful energy. Fossil fuels are the most abundant energy source used today. However, their burning results in a relevant and, at times, significant impact on the environment as a whole. The combustion process leads to the generation of emissions to air, water and soil, of which emissions to the air are considered to be one of the main environmental concerns.

The most important emissions to air from the combustion of fossil fuels are SO_2, NO_X, CO, particulate matter (PM_{10}) and greenhouse gases, such as N_2O and CO_2. Other substances such as heavy metals, halide compounds, and dioxins are emitted in smaller quantities.

Conditions

The BAT associated emission levels are based on daily average, standard conditions and an O_2 level of 6 % / 3 % / 15 % (solid fuels / liquid and gasous fuels / gas turbines) which represents a typical load situation. For peak loads, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher, have to be considered.

Unloading, storage and handling of fuel and additives

Some BAT for preventing releases from the unloading, storage and handling of fuels, and also for additives such as lime, limestone, ammonia, etc. are summarised in Table 1.

	BAT
Particulate matter	• the use of loading and unloading equipment that minimises the height of fuel drop to the stockpile, to reduce the generation of fugitive dust (solid fuels) • in countries where freezing does not occur, using water spray systems to reduce the formation of fugitive dust from solid fuel storage (solid fuels) • placing transfer conveyors in safe, open areas aboveground so that damage from vehicles and other equipment can be prevented (solid fuels) • using enclosed conveyors with well designed, robust extraction and filtration equipment on conveyor transfer points to prevent the emission of dust (solid fuels) • rationalising transport systems to minimise the generation and transport of dust on site (solid fuels) • the use of good design and construction practices and adequate maintenance (all fuels) • storage of lime or limestone in silos with well designed, robust extraction and filtration equipment (all fuels)
Water contamination	• having storage on sealed surfaces with drainage, drain collection and water treatment for settling out (solid fuels) • the use of liquid fuel storage systems that are contained in impervious bunds that have a capacity capable of containing 75 % of the maximum capacity of all tanks or at least the maximum volume of the largest tank. Tank contents should be displayed and associated alarms used and automatic control systems can be applied to prevent the overfilling of storage tanks (solid fuels) • pipelines placed in safe, open areas aboveground so that leaks can be detected quickly and damage from vehicles and other equipment can be prevented. For non-accessible pipes, double walled type pipes with automatic control of the spacing can be applied (liquid and gaseous fuels) • collecting surface run-off (rainwater) from fuel storage areas that washes fuel away and treating this collected stream (settling out or waste water treatment plant) before discharge (solid fuels)
Fire prevention	• surveying storage areas for solid fuels with automatic systems, to detect fires, caused by self-ignition and to identify risk points (solid fuels)
Fugitive emissions	• using fuel gas leak detection systems and alarms (liquid and gaseous fuels)
Efficient use of natural resources	• using expansion turbines to recover the energy content of the pressurised fuel gases (natural gas delivered via pressure pipelines) (liquid and gaseous fuels) • preheating the fuel gas by using waste heat from the boiler or gas turbine (liquid and gaseous fuels).
Health and safety risk regarding ammonia	• for handling and storage of pure liquified ammonia: pressure reservoirs for pure liquified ammonia >100 m^3 should be constructed as double wall and should be located subterraneously; reservoirs of 100 m^3 and smaller should be manufactured including annealling processes (all fuels) • from a safety point of view, the use of an ammonia-water solution is less risky than the storage and handling of pure liquefied ammonia (all fuels).

Table 1: Some BAT for storage and handling of fuel and additives

Fuel pretreatment

Fuel pretreatment of solid fuel mainly means blending and mixing in order to ensure stable combustion conditions and to reduce peak emissions. To reduce the amount of water in peat and biomass, drying of fuel is also considered to be part of BAT. For liquid fuels, the use of pretreatment devices, such as diesel oil cleaning units used in gas turbines and engines, are BAT. Heavy fuel oil (HFO) treatment comprises devices such as electrical or steam coil type heaters, de-emulsifier dosing systems, etc.

Thermal efficiency

Prudent management of natural resources and the efficient use of energy are two of the major requirements of the IPPC Directive. In this sense, the efficiency with which energy can be generated is an important indicator of the emission of the climate relevant gas CO_2. One way to reduce the emission of CO_2 per unit of energy generated is the optimisation of the energy utilisation and the energy generating process. Increasing the thermal efficiency has implications on load conditions, cooling system, emissions, use of type of fuel and so on.

Cogeneration (CHP) is considered as the most effective option to reduce the overall amount of CO_2 released and is relevant for any new build power plant whenever the local heat demand is high enough to warrant the construction of the more expensive cogeneration plant instead of the simpler heat or electricity only plant. The BAT conclusion to increase efficiency and the BAT associated levels are summarised in Tables 3 to 5. In this sense, it should be noted that HFO fired plants are considered to have similar efficiencies than coal fired plants.

Fuel	Combined technique	Unit thermal efficiency (net) (%)	
		New plants	Existing plants
Coal and lignite	Cogeneration (CHP)	75 – 90	75 – 90
Coal	PC (DBB and WBB)	43 – 47	The achievable improvement of thermal efficiency depends on the specific plant, but as an indication, a level of 36* – 40 % or an incremental improvement of more than 3 % points can be seen as associated with the use of BAT for existing plants
	FBC	>41	
	PFBC	>42	
Lignite	PC (DBB)	42 – 45	
	FBC	>40	
	PFBC	>42	

PC: pulverised combustion **DBB:** dry bottom boiler **WBB:** wet bottom boiler
FBC: fluidised bed combustion **PFBC:** pressurised fluidised bed combustion
* Some split views appeared in this value and are reported in Section 4.5.5 of the main document

Table 2: Levels of thermal efficiency associated with the application of BAT measures for coal and lignite fired combustion plants

Fuel	Combined technique	Unit thermal efficiency (net) (%)	
		Electric efficiency	Fuel utilisation (CHP)
Biomass	Grate-firing	Around 20	75 – 90 Depending on the specific plant application and the heat and electricity demand
	Spreader-stoker	>23	
	FBC (CFBC)	>28 – 30	
Peat	FBC (BFBC and CFBC)	>28 – 30	

FBC: fluidised bed combustion **CFBC:** circulating fluidised bed combustion
BFBC: bubbling fluidised bed combustion **CHP:** Cogeneration

Table 3: Thermal efficiency levels associated with the application of BAT measures for peat and biomass fired combustion plants

No specific thermal efficiency values were concluded when using liquid fuels in boilers and engines. However, some techniques to consider are available in the respective BAT sections.

Plant type	**Electrical efficiency (%)**		**Fuel utilisation(%)**
	New plants	**Existing plants**	**New and existing plants**
Gas turbine			
Gas turbine	36 – 40	32 – 35	-
Gas engine			
Gas engine	38 – 45		-
Gas engine with HRSG in CHP mode	>38	>35	75 – 85
Gas-fired boiler			
Gas-fired boiler	40 – 42	38 – 40	
CCGT			
Combined cycle with or without supplementary firing (HRSG) for electricity generation only	54 – 58	50 – 54	-
Combined cycle without supplementary firing (HRSG) in CHP mode	<38	<35	75 – 85
Combined cycle with supplementary firing in CHP mode	<40	<35	75 – 85
HRSG: heat recovery steam generator	**CHP**: Congeneration		

Table 4: Efficiency of gas-fired combustion plants associated to the use of BAT

Particulate matter (dust) emissions

Particulate matter (dust) emitted during the combustion of solid or liquid fuels arises almost entirely from their mineral fraction. By combustion of liquid fuels, poor combustion conditions lead to the formation of soot. Combustion of natural gas is not a significant source of dust emissions. The emission levels of dust, in this case, are normally well below 5 mg/Nm^3 without any additional technical measures being applied.

For dedusting off-gases from new and existing combustion plants, BAT is considered to be the use of an electrostatic precipitator (ESP) or a fabric filter (FF), where a fabric filter normally achieves emission levels below 5 mg/Nm^3. Cyclones and mechanical collectors alone are not BAT, but they can be used as a pre-cleaning stage in the flue-gas path.

The BAT conclusion for dedusting and the associated emission levels are summarised in Table 5. For combustion plants over 100 MW$_{th}$, and especially over 300 MW$_{th}$, the dust levels are lower because the FGD techniques, which are already a part of the BAT conclusion for desulphurisation, also reduce particulate matter.

Capacity (MW$_{th}$)	**Dust emission level (mg/Nm^3)**						**BAT to reach these levels**
	Coal and lignite		**Biomass and peat**		**Liquid fuels for boilers**		
	New plants	**Existing plants**	**New plants**	**Existing plants**	**New plants**	**Existing plants**	
50 – 100	5 – 20*	5 – 30*	5 – 20	5 – 30	5 – 20*	5 – 30*	ESP or FF
100 – 300	5 – 20*	5 – 25*	5 – 20	5 – 20	5 – 20*	5 – 25*	ESP or FF in combination FGD (wet, sd or dsi) for PC ESP or FF for FBC
>300	5 – 10*	5 – 20*	5 – 20	5 – 20	5 – 10*	5 – 20*	

Notes:
ESP: Electrostatic precipitator) **FF:** Fabric filter **FGD(wet):** Wet flue-gas desulphurisation
FBC: Fluidised bed combustion) **sd:** semi dry **dsi:** dry sorbent injection
* Some split views appeared in these values and are reported in Sections 4.5.6 and 6.5.3.2 of the main document.

Table 5: BAT for the reduction of particulate emissions from some combustion plants

Heavy metals

The emission of heavy metals results from their presence as a natural component in fossil fuels. Most of the heavy metals considered (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, V, Zn) are normally released as compounds (e.g. oxides, chlorides) in association with particulates. Therefore, BAT to reduce the emissions of heavy metals is generally the application of high performance dedusting devices such as ESPs or FFs.

Only Hg and Se are at least partly present in the vapour phase. Mercury has a high vapour pressure at the typical control device operating temperatures, and its collection by particulate matter control devices, is highly variable. For ESPs or FFs operated in combination with FGD techniques, such as wet limestone scrubbers, spray dryer scrubbers or dry sorbent injection, an average removal rate of Hg is 75 % (50 % in ESP and 50 % in FGD) and 90 % in the additional presence of a high dust SCR can be obtained.

SO_2 emissions

Emissions of sulphur oxides mainly result from the presence of sulphur in the fuel. Natural gas is generally considered free from sulphur. This is not the case for certain industrial gases and desulphurisation of the gaseous fuel might then be necessary.

In general, for solid and liquid-fuel-fired combustion plants, the use of low sulphur fuel and/or desulphurisation is considered to be BAT. However, the use of low sulphur fuel for plants over 100 MW_{th} can, in most cases, only be seen as a supplementary measure to reduce SO_2 emissions in combination with other measures.

Besides the use of low sulphur fuel, the techniques that are considered to be BAT are mainly the wet scrubber (reduction rate 92 – 98 %), and the spray dry scrubber desulphurisation (reduction rate 85 – 92 %), which already has a market share of more than 90 %. Dry FGD techniques such as dry sorbent injection are used mainly for plants with a thermal capacity of less than 300 MW_{th}. The wet scrubber has the advantage of also reducing emissions of HCl, HF, dust and heavy metals. Because of the high costs, the wet scrubbing process is not considered as BAT for plants with a capacity of less than 100 MW_{th}.

Capacity (MW_{th})	**SO_2 emission level (mg/Nm^3)**						**BAT to reach these levels**
	Coal and lignite		**Peat**		**Liquid fuels for boilers**		
	New plants	**Existing plants**	**New plants**	**Existing plants**	**New plants**	**Existing plants**	
50 – 100	200 – 400* 150 – 400* (FBC)	200 – 400* 150 – 400* (FBC)	200 – 300	200 – 300	100 – 350*	100 – 350*	Low sulphur fuel or/and FGD (dsi) or FGD (sds) or FGD (wet) (depending on the plant size). Seawater scrubbing. Combined techniques for the reduction of NO_x and SO_2. Limestone injection (FBC).
100 – 300	100 – 200	100 – 250*	200 – 300 150 – 250 (FBC)	200 – 300 150 -300 (FBC)	100 – 200*	100 – 250*	
>300	20 – 150* 100 – 200 (CFBC/ PFBC)	20 – 200* 100 – 200* (CFBC/ PFBC)	50 – 150 50 – 200 (FBC)	50 – 200	50 – 150*	50 – 200*	

Notes:
FBC: Fluidised bed combustion
CFBC: Circulating fluidised bed combustion
PFBC: Pressurised fluidised bed combustion
FGD(wet): Wet flue-gas desulphurisation
FGD(sds): Flue-gas desulphurisation by using a spray dryer
FGD(dsi): Flue-gas desulphurisation by dry sorbent injection
* Some split views appeared in these values and are reported in Sections 4.5.8 and 6.5.3.3 of the main document.

Table 6: BAT for the reduction of SO_2 emissions from some combustion plants

NO_X emissions

The principal oxides of nitrogen emitted during the combustion are nitric oxide (NO) and nitrogen dioxide (NO_2), referred as NO_x.

For pulverised coal combustion plants, the reduction of NO_X emissions by primary and secondary measures, such as SCR, is BAT, where the reduction rate of the SCR system ranges between 80 and 95 %. The use of SCR or SNCR has the disadvantage of a possible emission of unreacted ammonia (‘ammonia slip’). For small solid fuel-fired plants without high load variations and with a stable fuel quality, the SNCR technique is also regarded as BAT in order to reduce NO_X emissions.

For pulverised lignite and peat-fired combustion plants, the combination of different primary measures is considered as BAT. This means, for instance, the use of advanced low NO_x burners in combination with other primary measures such as flue-gas recirculation, staged combustion (air-staging), reburning, etc. The use of primary measures tends to cause incomplete combustion, resulting in a higher level of unburned carbon in the fly ash and some carbon monoxide emissions.

In FBC boilers burning solid fuel, BAT is the reduction of NO_X emissions achieved by air distribution or by flue-gas recirculation. There is a small difference in the NO_X emissions from BFBC and CFBC combustion.

The BAT conclusion for the reduction of NO_X emissions and the associated emission levels for various fuels are summarised in Tables 8, 9 and 10.

Capacity (MW_{th})	**Combustion technique**	**NO_X emission level associated with BAT (mg/Nm^3)**			**BAT options to reach these levels**
		New plants	Existing plants	Fuel	
50 – 100	Grate-firing	200 – 300*	200 – 300*	Coal and lignite	Pm and/or SNCR
	PC	90 – 300*	90 – 300*	Coal	Combination of Pm and SNCR or SCR
	CFBC and PFBC	200 – 300	200 – 300	Coal and lignite	Combination of Pm
	PC	200 – 450	200 – 450*	Lignite	
100 – 300	PC	90* – 200	90 – 200*	Coal	Combination of Pm in combination with SCR or combined techniques
	PC	100 – 200	100 – 200*	Lignite	Combination of Pm
	BFBC, CFBC and PFBC	100 – 200	100 – 200*	Coal and Lignite	Combination of Pm together with SNCR
>300	PC	90 – 150	90 – 200	Coal	Combination of Pm in combination with SCR or combined techniques
	PC	50 – 200*	50 – 200*	Lignite	Combination of Pm
	BFBC,CFBC and PFBC	50 – 150	50 – 200	Coal and Lignite	Combination of Pm

Notes:
PC: Pulverised combustion
BFBC: Bubbling fluidised bed combustion
CFBC: Circulating fluidised bed combustion
PFBC: Pressurised fluidised bed combustion
Pm: Primary measures to reduce NO_x
SCR: Selective catalytic reduction of NO_x
SNCR: Selective non catalytic reduction of NO_x
The use of anthracite hard coal may lead to higher emission levels of NO_X because of the high combustion temperatures
* Some split views appeared in these values and are reported in Section 4.5.9 of the main document.

Table 7: BAT for the reduction of NO_X from coal-and lignite-fired combustion plants

Capacity (MW_{th})	NO_X -emission level (mg/Nm^3)				BAT to reach these levels
	Biomass and Peat		Liquid fuels		
	New plants	Existing plants	New plants	Existing plants	
50 – 100	150 – 250	150 – 300	150 – 300*	150 – 450	Combination of Pm SNCR/ SCR or combined techniques
100 – 300	150 – 200	150 – 250	50 – 150*	50 – 200*	
>300	50 – 150	50 – 200	50 – 100*	50 – 150*	

Notes:
Pm: Primary measures to reduce NO_x **SCR:** Selective catalytic reduction of NO_x
* Some split views appeared in these values and are reported in Section 6.5.3.4 of the main document

Table 8: BAT for the reduction of NO_X from peat, biomass and liquid fuel-fired combustion plants

For new gas turbines, dry low NO_X premix burners (DLN) are BAT. For existing gas turbines, water and steam injection or conversion to the DLN technique is BAT. For gas-fired stationary engine plants, the lean-burn approach is BAT analogous to the dry low NO_X technique used in gas turbines.

For most gas turbines and gas engines, SCR is also considered to be BAT. Retrofitting of an SCR system to a CCGT is technically feasible but is not economically justified for existing plants. This is because the required space in the HRSG was not foreseen in the project and is, therefore, not available.

Plant type	Emission level associated with BAT (mg/Nm^3)		O_2 level (%)	BAT options to reach these levels
	NO_x	CO		
Gas turbines				
New gas turbines	20 – 50	5 – 100	15	Dry low NO_x premix burners or SCR
DLN for existing gas turbines	20 – 75	5 – 100	15	Dry low NO_x premix burners as retrofitting packages if available
Existing gas turbines	50 – 90*	30 – 100	15	Water and steam injection or SCR
Gas engines				
New gas engines	20 – 75*	30 – 100*	15	Lean-burn concept or SCR and oxidation catalyst for CO
New gas engine with HRSG in CHP mode	20 – 75*	30 – 100*	15	Lean-burn concept or SCR and oxidation catalyst for CO
Existing gas engines	20 – 100*	30 – 100	15	Low NO_x tuned
Gas-fired boilers				
New gas-fired boilers	50 – 100*	30 – 100	3	Low NO_x burners or SCR or SNCR
Existing gas-fired boile	50 – 100*	30 – 100	3	
CCGT				
New CCGT without supplementary firing (HRSG)	20 – 50	5 – 100	15	Dry low NO_x premix burners or SCR
Existing CCGT without supplementary firing (HRSG)	20 – 90*	5 – 100	15	Dry low NO_x premix burners or water and steam injection or SCR
New CCGT with supplementary firing	20 – 50	30 – 100	Plant spec.	Dry low NO_x premix burners and low NO_x burners for the boiler part or SCR or SNCR
Existing CCGT with supplementary firing	20 – 90*	30 – 100	Plant spec.	Dry low NO_x premix burners or water and steam injection and low NO_x burners for the boiler part or SCR or SNCR

SCR: Selective catalytic reduction of NO_x **SNCR**: Selective non catalytic reduction of NO_x
DLN: dry low NO_X **HRSG:** heat recovery steam generator **CHP:** Cogeneration
CCGT: combined cycle gas turbine
* Some split views appeared on these values and are reported in Section 7.5.4 of the main document..

Table 9: BAT for the reduction of NO_X and CO emissions from gas-fired combustion plants

CO emissions

Carbon monoxide (CO) always appears as an intermediate product of the combustion process, BAT for the minimisation of CO emissions is complete combustion, which goes along with good furnace design, the use of high performance monitoring and process control techniques, and maintenance of the combustion system. Some emission levels associated to the use of BAT for different fuels are present in the BAT sections, however in this executive summary only the ones from gas-fired combustion plants are reported.

Water contamination

Besides the generation of air pollution, large combustion plants are also a significant source of water discharge (cooling and waste water) into rivers, lakes and the marine environment.

Any surface run-off (rainwater) from the storage areas that washes fuel particles away should be collected and treated (settling out) before being discharged. Small amounts of oil contaminated (washing) water cannot be prevented from occurring occasionally at a power plant. Oil separation wells are BAT to avoid any environmental damage.

The BAT conclusion for wet scrubbing desulphurisation is related to the application of a waste water treatment plant. The waste water treatment plant consists of different chemical treatments to remove heavy metals and to decrease the amount of solid matter from entering the water. The treatment plant includes an adjustment of the pH level, the precipitation of heavy metals and removal of the solid matter. The full document contains some emission levels.

Waste and residues

A lot of attention has already been paid by the sector to the utilisation of combustion residues and by-products, instead of just depositing them in landfills. Utilisation and re-use is, therefore, the best available option and has priority. There are many different utilisation possibilities for different by-products such as ashes. Each different utilisation option has different specific criteria. It has not been possible to cover all these criteria in this BREF. The quality criteria are usually connected to the structural properties of the residue and the content of harmful substances, such as the amount of unburned fuel or the solubility of heavy metals, etc.

The end-product of the wet scrubbing technique is gypsum, which is a commercial product for the plant in most EU countries. It can be sold and used instead of natural gypsum. Practically most of the gypsum produced in power plants is utilised in the plasterboard industry. The purity of gypsum limits the amount of limestone that can be fed into the process.

Co-combustion of waste and recovered fuel

Large combustion plants, designed and operated according to BAT, operate effective techniques and measures for the removal of dust (including partly heavy metals), SO_2 NO_x, HCl, HF and other pollutants as well as techniques to prevent water and soil contamination. In general, these techniques can be seen as sufficient and are, therefore, also considered as BAT for the co-combustion of secondary fuel. The basis for this is that the BAT conclusions and, in particular, the emission levels associated with the use of BAT as defined in the fuel specific chapters. A higher input of pollutants into the firing system can be balanced within certain limits by adaptation of the flue-gas cleaning system or by limitation of the percentage of secondary fuel that can be co-combusted.

Regarding the impact of co-combustion to the quality of the residues, the main BAT issue is maintaining the quality of gypsum, ashes, slag and other residues and by-products at the same level as those occurring without the co-combustion of secondary fuel for the purpose of recycling. If co-combustion leads to significant (extra) disposal volumes of by-products or residues or extra contamination by metals (e.g. Cd, Cr, Pb) or dioxins, additional measures need to be taken to avoid this.

Degree of Consensus

This document as a whole has a lot of support from the TWG Members. However, industry and mainly two Member States did not express their full support for this final draft and stated with so-called ‘split views’ to some of the conclusions presented in the document, in particular to the BAT associated efficiency and emission levels for coal and lignite, liquid and gaseous fuels, as well as for the use of SCR due to economical reasons. They contested that the ranges given as emission levels associated with the use of BAT are, in general, too low for both new and existing power plants. However, it should be noted that the upper levels of the BAT associated emission levels, in particular for existing plants, are similar to some current ELVs set in some European Member States. Part of industry has expressed a particular view on the extend to which this document reflects the experiences and circumstances of all large combustion plants. This supports the TWG Members view that BAT levels are reasonable and illustrate that the considered BAT levels are already being achieved by a good number of plants in Europe.

The EC is launching and supporting, through its RTD programmes, a series of projects dealing with clean technologies, emerging effluent treatment and recycling technologies and management strategies. Potentially these projects could provide a useful contribution to future BREF reviews. Readers are, therefore, invited to inform the EIPPCB of any research results which are relevant to the scope of this document (see also the preface of this document).

PREFACE

1. Status of this document

Unless otherwise stated, references to “the Directive” in this document means the Council Directive 96/61/EC on integrated pollution prevention and control. As the Directive applies without prejudice to Community provisions on health and safety at the workplace, so does this document.

This document forms part of a series presenting the results of an exchange of information between EU Member States and industries concerned on best available technique (BAT), associated monitoring, and developments in them. It is published by the European Commission pursuant to Article 16(2) of the Directive, and must therefore be taken into account in accordance with Annex IV of the Directive when determining “best available techniques”.

2. Relevant legal obligations of the IPPC Directive and the definition of BAT

In order to help the reader understand the legal context in which this document has been drafted, some of the most relevant provisions of the IPPC Directive, including the definition of the term ‘best available techniques’, are described in this preface. This description is inevitably incomplete and is given for information only. It has no legal value and does not in any way alter or prejudice the actual provisions of the Directive.

The purpose of the Directive is to achieve integrated prevention and control of pollution arising from the activities listed in its Annex I, leading to a high level of protection of the environment as a whole. The legal basis of the Directive relates to environmental protection. Its implementation should also take account of other Community objectives such as the competitiveness of the Community’s industry thereby contributing to sustainable development.

More specifically, it provides for a permitting system for certain categories of industrial installations requiring both operators and regulators to take an integrated, overall look at the polluting and consuming potential of the installation. The overall aim of such an integrated approach must be to improve the management and control of industrial processes so as to ensure a high level of protection for the environment as a whole. Central to this approach is the general principle given in Article 3 that operators should take all appropriate preventative measures against pollution, in particular through the application of best available techniques enabling them to improve their environmental performance.

The term ‘best available techniques’ is defined in Article 2(11) of the Directive as “the most effective and advanced stage in the development of activities and their methods of operation which indicate the practical suitability of particular techniques for providing in principle the basis for emission limit values designed to prevent and, where that is not practicable, generally to reduce emissions and the impact on the environment as a whole”. Article 2(11) goes on to clarify further this definition as follows:

‘techniques’ includes both the technology used and the way in which the installation is designed, built, maintained, operated and decommissioned;

‘available’ techniques are those developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages, whether or not the techniques are used or produced inside the Member State in question, as long as they are reasonably accessible to the operator;

‘best’ means most effective in achieving a high general level of protection of the environment as a whole.

Furthermore, Annex IV of the Directive contains a list of "considerations to be taken into account generally or in specific cases when determining best available techniques ... bearing in mind the likely costs and benefits of a measure and the principles of precaution and prevention". These considerations include the information published by the Commission pursuant to Article 16(2).

Competent authorities responsible for issuing permits are required to take account of the general principles set out in Article 3 when determining the conditions of the permit. These conditions must include emission limit values, supplemented or replaced where appropriate by equivalent parameters or technical measures. According to Article 9(4) of the Directive, these emission limit values, equivalent parameters and technical measures must, without prejudice to compliance with environmental quality standards, be based on the best available techniques, without prescribing the use of any technique or specific technology, but taking into account the technical characteristics of the installation concerned, its geographical location and the local environmental conditions. In all circumstances, the conditions of the permit must include provisions on the minimisation of long-distance or transboundary pollution and must ensure a high level of protection for the environment as a whole.

Member States have the obligation, according to Article 11 of the Directive, to ensure that competent authorities follow or are informed of developments in best available techniques.

3. Objective of this Document

Article 16(2) of the Directive requires the Commission to organise 'an exchange of information between Member States and the industries concerned on best available techniques, associated monitoring and developments in them', and to publish the results of the exchange.

The purpose of the information exchange is given in recital 25 of the Directive, which states that 'the development and exchange of information at Community level about best available techniques will help to redress the technological imbalances in the Community, will promote the worldwide dissemination of limit values and techniques used in the Community and will help the Member States in the efficient implementation of this Directive.'

The Commission (Environment DG) established an information exchange forum (IEF) to assist the work under Article 16(2) and a number of technical working groups have been established under the umbrella of the IEF. Both IEF and the technical working groups include representation from Member States and industry as required in Article 16(2).

The aim of this series of documents is to reflect accurately the exchange of information which has taken place as required by Article 16(2) and to provide reference information for the permitting authority to take into account when determining permit conditions. By providing relevant information concerning best available techniques, these documents should act as valuable tools to drive environmental performance.

4. Information Sources

This document represents a summary of information collected from a number of sources, including in particular the expertise of the groups established to assist the Commission in its work, and verified by the Commission services. All contributions are gratefully acknowledged.

5. How to understand and use this document

The information provided in this document is intended to be used as an input to the determination of BAT in specific cases. When determining BAT and setting BAT-based permit conditions, account should always be taken of the overall goal to achieve a high level of protection for the environment as a whole.

The type of information that is provided in each section of the document is described here.

Chapter 1 provides general information on the industrial sector and describes the key environmental issues.

Chapter 2 gives an introduction to the principles and concepts of combustion cycles and energy generation. This is only a brief description but is provided to assist reader understanding of combustion technology and energy generation.

Chapter 3 provides information on common processes and techniques used across the sector to reduce emissions from large combustion plants.

Chapters 4 to 8 provide information on techniques used for the combustion of different fuels. Each chapter is dedicated to a different fuel type, hence these chapters are later referred to as ‘the fuel specific chapters’. The structure of these chapters is based on the general BREF outline:

- Section one of each chapter (Chapters 4 to 8) provides information on applied processes and techniques used for the combustion of the particular fuels.

- Section two of each chapter (Chapter 4 to 8) provides examples of applied techniques and processes for the combustion of the particular fuels.

- Section three of each chapter (Chapters 4 to 8) presents information on consumption levels, reflecting the situation in existing installations at the time of writing.

- Section four of each chapter (Chapters 4 to 8) describes in more detail the emission reduction and other techniques that are considered to be the most relevant for determining BAT and BAT-based permit conditions. This information includes details on consumption levels, thermal efficiencies and emission levels considered achievable by using the technique; some indication of the level and type of costs; and information on the cross-media effects associated with the technique; and also a details on the extent to which the technique is applicable to the range of installations requiring IPPC permits, for example whether it is applicable to new, existing, large or small installations. Techniques that are generally seen as obsolete are not included.

- The final section of each chapter (Chapters 4 to 8) is a ‘conclusions section’. This presents the techniques and the consumption, thermal efficiency and emission levels that are considered to be compatible with BAT in a general sense. The purpose of this section is thus to provide general indications regarding the consumption, thermal efficiency and emission levels that can be considered as an appropriate reference point to assist in the determination of BAT-based permit conditions or for the establishment of general binding rules under Article 9(8) of the Directive.

It should be stressed, however, that this document does not propose emission limit values. The determination of appropriate permit conditions will involve taking account of local, site-specific factors such as the technical characteristics of the installation concerned, its geographical location and the local environmental conditions. In the case of existing installations, the economic and technical viability of upgrading them also needs to be taken into account. Even the single objective of ensuring a high level of protection for the environment as a whole will often involve making trade-off judgements between different types of environmental impact, and these judgements will often be influenced by local considerations.

Although an attempt is made to address some of these issues, it is not possible for them to be fully considered in this document. The techniques and levels presented in the conclusion section on Best Available Techniques in each of the fuels specific chapters (Chapters 4 to 8) will therefore, not necessarily be appropriate for all installations. On the other hand, the obligation to ensure a high level of environmental protection, including the minimisation of long-distance or transboundary pollution, implies that permit conditions cannot be set on the basis of purely local considerations. It is, therefore, of the utmost importance that the information contained in this document is fully taken into account by permitting authorities.

Since the best available techniques will change over time, this document will be reviewed and updated as appropriate. All comments and suggestions should be made to the European IPPC Bureau at the Institute for Prospective Technological Studies at the following address:

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6. Interface between the IPPC and the Large Combustion Plants Directives

The following presentation of the issues is related to the interface between Directive 2001/80/EC of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants (LCP Directive) and Directive 96/61/EC of 24 September 1996 concerning integrated pollution prevention and control (IPPC Directive).

It should be noted that the ultimate interpretation of Community law is a matter for the European Court of Justice and therefore it cannot be excluded that interpretation by the Court may raise new issues in the future.

The LCP Directive contains the following main explicit references to the IPPC Directive:

- Recital 8 of the LCP Directive states that “Compliance with the emission limit values laid down by this Directive should be regarded as a necessary but not sufficient condition for compliance with the requirements of Directive 96/61/EC regarding the use of best available techniques. Such compliance may involve more stringent emission limit values, emission limit values for other substances and other media, and other appropriate conditions.” The recital makes clear that compliance with the emissions limit values laid down in the LCP Directive does not remove the obligation to comply with the IPPC Directive, in particular to operate in compliance with a permit (Article 9(4) of the IPPC Directive) containing conditions determined in accordance with the Directive.

- Article 4(3) and 4(6) of the LCP Directive provides for the possibility for Member States to establish a national emission reduction plan for existing installations or to apply emission limit values specified in the LCP Directive to existing plant. However, the plan “may under no circumstances exempt a plant from the provisions laid down in relevant Community legislation, inter alia Directive 96/61/EC.” Therefore, even if an installation is covered by a national plan, it still needs to operate in compliance with all the provisions of the IPPC Directive, including a permit containing emission limit values or equivalent parameters and technical measures determined according to the provisions of Article 9(4) or Article 9(8) of the IPPC Directive. In addition, as presented in the standard BREF preface, a certain flexibility is anchored in the provisions of Article 9(4) of the IPPC Directive as well as in the definition of BAT.

- Article 4(4) of the LCP Directive provides for a possible exemption for “end of life” installations from compliance with emission limit values or from inclusion in a national plan, “without prejudice to Directive 96/61/EC”. As in the previous case, the installation concerned still needs to operate according to an “IPPC permit”. As presented above, the provisions of Article 9(4) of the IPPC Directive and the BAT definition enable the competent authorities to take into account the specificities of such “end of life” installations. In addition, the applicant should attach the written declaration according to Article 4(4)(a) of the LCP Directive to the documents listed in Article 6 of the IPPC Directive concerning applications for permits.

Best Available Techniques Reference Document for Large Combustion Plants

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SCOPE AND ORGANISATION OF THE DOCUMENT

In accordance with Annex I of the IPPC Directive this BREF covers, in general, combustion installations with a rated thermal input exceeding 50 MW; plants with a thermal input lower than 50 MW will, however, be discussed where technically relevant because smaller units can potentially be added to a plant to build one larger installation exceeding 50 MW. This means that all kinds of conventional power plants (e.g. utility boiler, combined heat and power plants, district heating plants, etc.) used for mechanical power and heat generation are covered by this work. Industrial combustion installations are covered as far as they use conventional fuel. The commercial availability of the fuel on the market has been used as an indicator to identify conventional fuels. The criteria for classifying a fuel as a ‘conventional fuel’ is a known composition which remains relatively constant, and indeed is usually standardised. Coal, lignite, biomass, peat, liquid and gaseous fuels (including hydrogen and biogas) are regarded as conventional fuels.

The following combustion installations on industrial sites, for example, are not covered by this BREF on large combustion plants:

- combustion installations which use process-related residues or by-products as fuel, for example the black liquor boiler used in the pulp and paper industry, or combustion installations using refinery fuel gas and liquid fuels that cannot be sold as a specified fuel on the fuel market
- installations where the combustion process is an integrated part of a specific production, for example the coke oven used in the iron and steel industry, or the pulp and paper industry, or the cement kiln used for the production of cement.

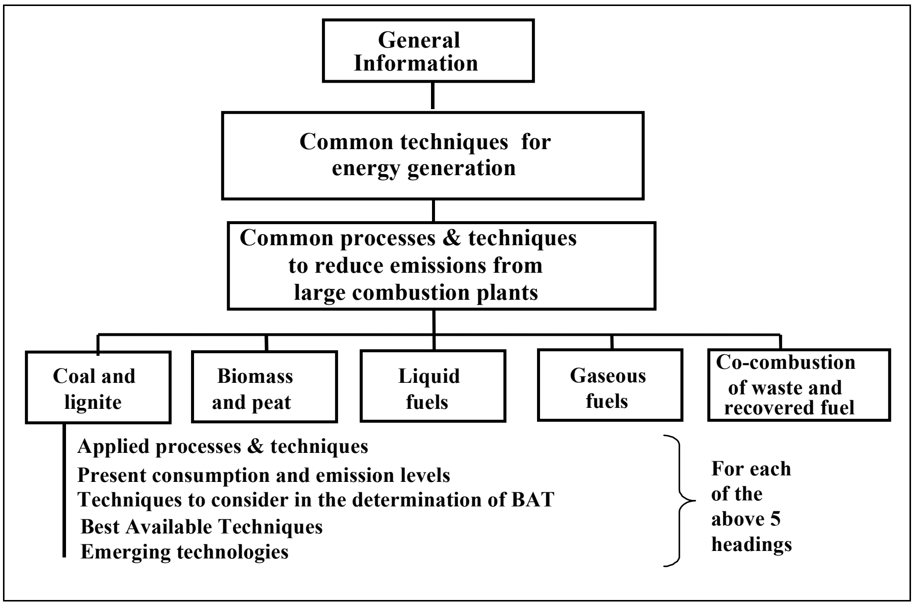
The co-combustion of a certain percentage of secondary fuel such as waste, recovered fuel, sewage sludge or biomass-derived fuel (contaminated wood) is currently practised in some combustion plants in Europe. Due to possible differences in the combustion process when using these fuels, it was decided to describe co-combustion in a separate chapter of this BREF document (i.e. Chapter 8).

Within the scope of this BREF, it is assumed that secondary fuels are pretreated before they enter the large combustion plant, which usually first involves separating the combustible parts from the non-combustible parts. These pretreatment issues (e.g. sorting, crushing, preparation) are dealt with in the Waste Treatment BREF.

Large combustion plants are classified and operated according to the demands and requirements on them, with the plants being classified as base-load, middle-load or peak-load plants. Their loading can vary from part load up to full load. Their operating hours can also vary, from just a few hours of energy generation per year up to full time operation. Because of this wide variability, this BREF cannot possibly provide BAT conclusions for every different operational mode.

This BREF covers not only the combustion unit, but also upstream and downstream activities that are directly associated with the combustion process. That means this document describes for instance, fuel handling as well as off-gas treatment, the handling of combustion residues and raw water treatment.

Heat and power generation in Europe is a diverse sector. Energy generation using fossil fuels is based on a variety of fuels, which can generally be classified by their aggregate state into solid, liquid or gaseous fuels. This BREF has, therefore, been written vertically, fuel by fuel, but with common aspects and techniques described together in the three introductory chapters. The organisation of this BREF is schematically shown in the following graphic:



Organisation of the BREF on large combustion plants

1 GENERAL INFORMATION

1.1 Industry overview

The growth in world consumption of commercial primary energy (coal, oil, gas) was very buoyant during the 1960s, with a mean annual increase of 5 % from 1960 to 1973. However, world growth experienced a distinct slowdown after the first oil crisis in 1979 (growth reduced to +3.1 % per year from 1973 to 1979) and even fell after the second oil crisis in 1979 (consumption fell by -0.7 % per year from 1979 to 1982).

From 1983, and particularly after 1986, with the recovery from the oil crises (reflected by a reduction in oil prices by half) and with the return to stronger economic growth in industrialised countries, the increase in energy consumption has resumed, with higher growth rates returning (+3 % from 1983 to 1989).

After stagnating in 1990 and then increasing by about 0.5 % in 1991, world energy demand remained roughly constant in 1992, although with considerable regional contrasts, i.e. moderate growth in the US (+1.8 %), strong growth in Asia (+5 %), a substantial reduction in Eastern Europe (-8 %) and virtual stagnation in Western Europe [4, OSPAR, 1997].

Figure 1.1 shows the worldwide energy sources in the power-generating sector for 1995.

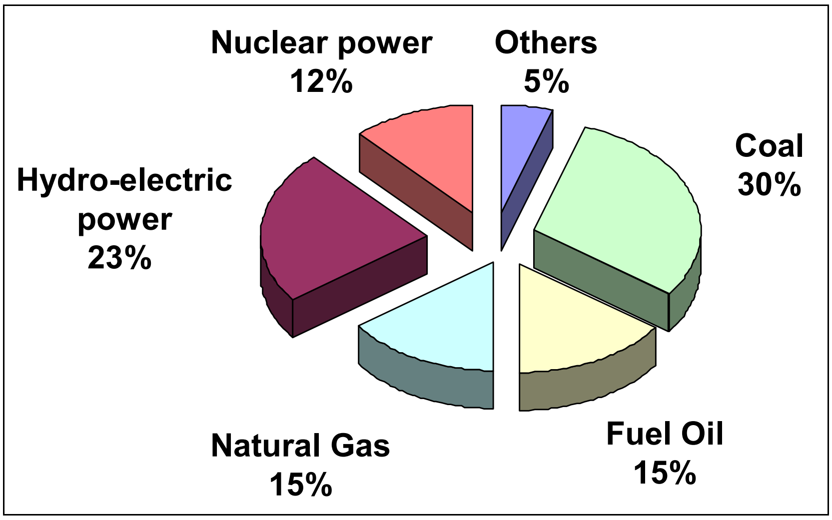


Figure 1.1: Worldwide energy sources in the power-generating sector (1995)
[32, Rentz, et al., 1999]

Around half of the electricity generated worldwide is produced from different fossil fuels, with 30 % being generated from coal [133, Strömberg, 2001].

Figure 1.2 shows the major differences in the use of different energy sources combusted for power generation between different world regions in 1997.

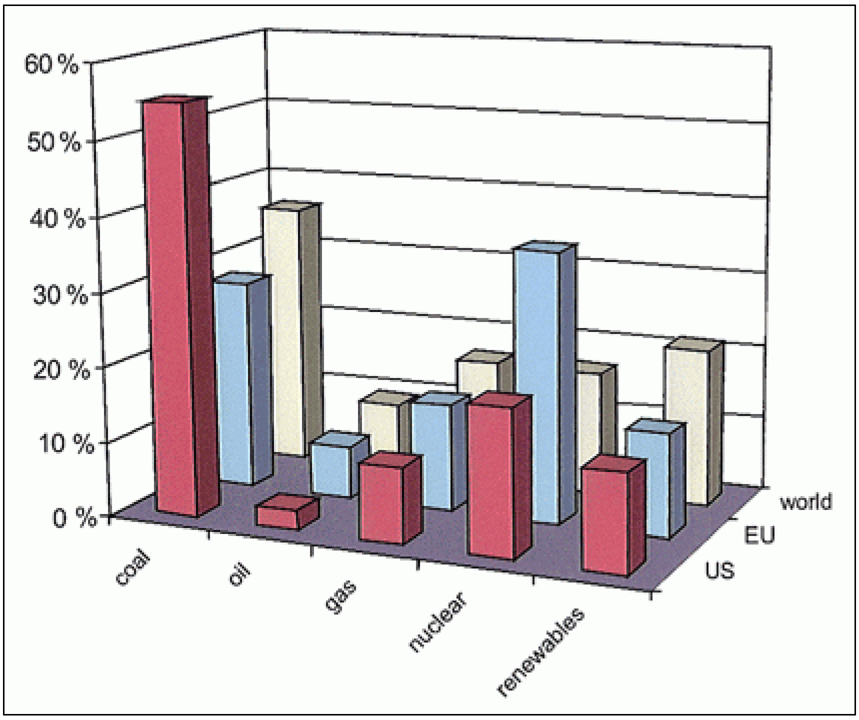


Figure 1.2: Energy consumption for electricity generation by fuel (1997)
[105, Steen, 2001]

In 1997, there were in the region of 1214 companies generating electrical and thermal energy throughout the EU. In addition, there were approximately 590 industrial companies operating industrial combustion plants and producing electrical and thermal energy to cover their own plant's demand.

Also in 1997, about 90 % of the entire power generation of electricity in the EU of approximately 2423 TWh gross, was carried out by plants owned by large electricity generating companies, with only about 10 % being accounted for by industrial combustion plants.

Although the high tension and the extra high tension grid used for the transmission of electricity was operated by only 35 companies in the EU, power distribution to the end-customer was carried out by 2050 companies (status: 1997).

In 1997, the plant capacity installed Europe-wide amounted to a total of approximately 580 GW (recorded as 'net electrical capacity'), including approximately 307 GW (approximately 53 %) of conventional thermal power stations. Table 1.1 shows the subdivision of electric power generation plants.

Type of power plant		**GW**	**% of total**
Fossil fuel-fired power plants	Steam	249.679	43.03
	Gas turbines	25.310	4.36
	Combined cycles	25.776	4.44
	Internal combustion	5.873	1.01
Nuclear power plants		124.151	21.40
Hydropower plants	Total installed capacity	116.189	20.02
	Pumped storage	29.686	5.12
Geothermal		0.539	0.1
Wind		3.024	0.51
Total capacity of all installed plants		580.227	

Table 1.1: Installed electrical capacity in EU-15 Member States
[58, Eurelectric, 2001]

In the European Union all available types of energy sources are used for electric and thermal power generation. The type of fuel used for energy generation in each EU Member State is largely influenced by national fuel resources such as the local or national availability of coal, lignite, natural gas or oil. For example, in Greece and in parts of Germany and Poland significant lignite resources are available for energy generation. In Finland and Ireland, for instance peat is an important domestic energy source and, therefore, an important cornerstone of the national energy policy. In France, where nuclear power stations are applied to provide the major part of the nations energy demand, the use of fossil fuel is mainly restricted to a small number of peak-load plants.

Combustion plants are applied in the EU, according to their owners demands and requirements, as large utility plants or as industrial combustion plants providing electricity, steam, or heat to industrial production processes. Large combustion plants are classified and operated according to the demands and requirements of them. For the electricity supply industry, they are thus classified as: base-load, middle-load or peak-load plants. They can also be applied as spinning reserve power plants (mainly gas turbines which are operated as stand-by units), i.e. plants which are operated only to assure grid stability for densely populated urban areas or as emergency units. In this sense, their loading can vary from part load up to full load, and their operating hours can also vary, from just a few hours of energy generation per year up to full time operation.

The fossil fuels used are hard coal, lignite, petroleum products, natural gas, derived gases, biomass and peat and other fuels (e.g. tar, bitumen, petroleum coke). Nuclear energy is the second biggest source of electrical power generation, with a share of approximately 35 %. Renewable energies, among them in particular hydropower, generate approximately 14 % of the total (see Table 1.2).

Type of fuel		**Total gross electric power generation (GWh)**	**% of total**
Fossil fuel-fired power plants	Hard coal	471797	19.5
	Lignite	183140	7.6
	Petroleum products	185755	7.7
	Natural gas	332331	13.7
	Derived gases	27793	1.1
	Other fuels	7707	0.3
Biomass and peat		27283	1.1
Nuclear		859894	35.5
Hydro		316116	13.0
Geothermal		3957	0.2
Wind		6909	0.3
Total gross generation		2422682	

Table 1.2: Electric power gross generation in EU Member Sates in 1997
[58, Eurelectric, 2001]

The net production supplied to the grid was reported to be approximately 2300000 GWh (2300 TWh). The auxiliary power consumption of the power stations thus amounted to approximately 5.1 %.

As it accounts for over 50 % of the power generation, conventional thermal electricity predominates in Europe. However, examination of the development of the individual energy sources used in power stations since 1990 reflects the changing emphasis of European energy policy over that period, i.e. the growing influence of environmental-political decisions. Therefore, whilst the amount of electric power generated from fossil fuel energy sources increased by about 16 % and demand increased by about 14 %, the amount of electrical power generated from renewable energy sources (including hydropower and biomass) shows an above average increase of approximately 20 %.

Within the wide range of fossil energy sources used for electric power generation there have been some very different developments:

During the period under review (1990 – 1997), hard coal decreased by approximately 14 %, whereas natural gas showed an increase of approximately 134 %, and lignite increased by 49 %; although the increase in lignite can be solely accounted for by the inclusion of plants in the former East Germany, following German reunification.

Table 1.3 and Table 1.4 provides a summary of the most important figures concerning energy generation and consumption in the EU.

EUROPEAN UNION: Energy balance summary												
							Annual change					
	1990	**1997**	**2000**	**2010**	**2020**	**2030**	**1990/1997**	**1997/2000**	**2000/2010**	**2010/2020**	**2020/2030**	**2000/2030**
Population (million)	365.3	374.1	375.7	376.3	371.6	362.4	0.3 %	0.1 %	0.0 %	-0.1 %	-0.2 %	-0.1 %
GDP (USD$_{95}$ x 10^{9}ppa)	6806.1	7529.4	8163.8	10032.5	12157.1	13996.1	1.5 %	2.7 %	2.1 %	1.9 %	1.4 %	1.8 %
Per capita GDP (USD$_{95}$ x 10^{3}/cap)	18.6	20.1	21.7	26.7	32.7	38.6	1.1 %	2.6 %	2.1 %	2.1 %	1.7 %	1.9 %
Gross inland consumption/GDP (t/(USD$_{95}$ x 10^{3})	194.0	187.8	178.4	152.0	133.5	120.1	-0.5 %	-1.7 %	-1.6 %	-1.3 %	-1.1 %	-1.3 %
Gross inland consumption/capita (t/cap)	3.6	3.8	3.9	4.1	4.4	4.6	0.6 %	0.8 %	0.4 %	0.8 %	0.6 %	0.6 %
Electric generation./capita (kWh/cap)	5.9	6.4	6.4	7.1	8.4	9.9	1.2 %	0.0 %	1.0 %	1.7 %	1.6 %	1.4 %
CO$_{2}$ emissions (million tonnes of C)	869.4	858.5	903.0	927.4	1010.0	1057.4	-0.2 %	1.7 %	0.3 %	0.9 %	0.5 %	0.5 %
CO$_{2}$ emissions/capita (tonnes of C/cap)	2.4	2.3	2.4	2.5	2.7	2.9	-0.5 %	1.6 %	0.2 %	1.0 %	0.7 %	0.6 %
Primary production (million tonnes)	n.a.	725.2	774.6	631.7	612.1	595.4	n.a	2.2 %	-2.0 %	-0.3 %	-0.3 %	-0.9 %
Solids	212.8	126.6	125.6	101.4	105.8	110.1	-7.1 %	-0.3 %	-2.1 %	0.4 %	0.4 %	-0.4 %
Oil	123.7	163.5	167.4	82.1	47.1	38.7	4.1 %	0.8 %	-6.9 %	-5.4 %	-1.9 %	-4.8 %
Natural gas	131.2	179.3	213.9	167.0	170.6	140.3	4.6 %	6.1 %	-2.4 %	0.2 %	-1.9 %	-1.4 %
Nuclear	154.8	184.9	203.4	208.4	204.9	211.0	2.6 %	3.2 %	0.2 %	-0.2 %	0.3 %	0.1 %
Hydro + geothermal	24.0	27.5	27.6	29.0	30.2	31.0	1.9 %	0.2 %	0.5 %	0.4 %	0.3 %	0.4 %
Traditional biomass	17.2	17.0	17.3	18.2	19.2	20.4	-0.2 %	0.5 %	0.5 %	0.6 %	0.6 %	0.6 %
Other renewables	n.a.	26.4	19.4	25.6	34.1	43.9	n.a.	-9.7 %	2.8 %	2.9 %	2.6 %	2.8 %
Net imports (million tonnes)	639.6	658.2	681.8	893.2	1011.1	1085.0	0.4 %	1.2 %	2.7 %	1.2 %	0.7 %	1.6 %
Solids	90.2	96.9	106.4	110.3	154.9	197.4	1.0 %	3.2 %	0.4 %	3.4 %	2.5 %	2.1 %
Oil	432.8	435.9	441.1	540.7	599.3	602.8	0.1 %	0.4 %	2.1 %	1.0 %	0.1 %	1.0 %
Natural gas	89.4	117.6	134.3	242.3	256.9	284.9	4.0 %	4.5 %	6.1 %	0.6 %	1.0 %	2.5 %
Electricity	2.3	0.7	-0.1	-0.1	-0.1	-0.1	-16.3 %	n.a.	0.0 %	0.0 %	0.0 %	0.0 %
Gross inland consumption (million tonnes)	1320.6	1413.8	1456.4	1524.9	1623.2	1680.4	1.0 %	1.0 %	0.5 %	0.6 %	0.3 %	0.5 %
Solids	303.0	223.5	232.0	211.7	260.7	307.4	-4.3 %	1.3 %	-0.9 %	2.1 %	1.7 %	0.9 %
Oil	556.5	599.4	608.6	622.7	646.4	641.5	1.1 %	0.5 %	0.2 %	0.4 %	-0.1 %	0.2 %
Gas	220.6	296.9	348.2	409.3	427.6	425.2	4.3 %	5.5 %	1.6 %	0.4 %	-0.1 %	0.7 %
Others	n.a.	297.6	267.6	281.1	288.5	306.3	n.a.	-3.5 %	0.5 %	0.3 %	0.6 %	0.5 %

Table 1.3: European energy balance summary from 1990 to 2030 (prospective (estimated) energy outlook) [77, IEPE/IPTS, 2000]

EUROPEAN UNION: Energy balance summary

							Annual change					
	1990	**1997**	**2000**	**2010**	**2020**	**2030**	**1990/1997**	**1997/2000**	**2000/2010**	**2010/2020**	**2020/2030**	**2000/2030**
Electricity generation (TWh)	2164.9	2444.0	2463.9	2732.1	3193.9	3646.9	8.1 %	1.8 %	12.5 %	14.5 %	16.3 %	1.3 %
Thermal	1153.6	1218.4	1275.3	1479.2	1890.1	2258.3	0.8 %	1.5 %	1.5 %	2.5 %	1.8 %	1.9 %
of which:												
Coal	n.a.	n.a.	0.0	166.7	457.2	801.7	n.a.	n.a.	240.3 %	10.6 %	5.8 %	58.5 %
Gas turbines	46.2	149.0	263.6	444.2	544.8	642.1	18.2 %	20.9 %	5.4 %	2.1 %	1.7 %	3.0 %
Biomass	14.8	24.2	27.3	31.9	35.6	38.3	7.3 %	4.0 %	1.6 %	1.1 %	0.7 %	1.1 %
Nuclear	720.2	859.9	803.9	823.8	816.5	855.9	2.6 %	-2.2 %	0.2 %	-0.1 %	0.5 %	0.2 %
Hydro + geothermal	279.3	319.5	321.4	337.4	351.6	361.0	1.9 %	0.2 %	0.5 %	0.4 %	0.3 %	0.4 %
Solar	0.0	0.0	0.2	2.2	7.4	11.9	27.5 %	63.5 %	30.6 %	13.0 %	4.8 %	15.7 %
Wind	0.2	7.5	15.2	35.7	72.4	103.8	73.7 %	26.6 %	8.9 %	7.3 %	3.7 %	6.6 %
Small hydro	11.6	38.7	48.0	53.7	55.9	56.0	18.8 %	7.4 %	1.1 %	0.4 %	0.0 %	0.5 %
CHP	56.6	226.0	177.5	236.8	247.8	230.7	21.9 %	-7.7 %	2.9 %	0.5 %	-0.7 %	0.9 %
Generation capacity (GW_e)	392.3	546.5	593.9	743.0	840.4	946.4	4.9 %	2.8 %	2.3 %	1.2 %	1.2 %	1.6 %
Thermal	192.0	300.8	338.9	471.6	541.9	621.9	6.6 %	4.1 %	3.4 %	1.4 %	1.4 %	2.0 %
Nuclear	92.4	124.0	124.0	120.0	118.4	123.7	4.3 %	0.0 %	-0.3 %	-0.1 %	0.4 %	-0.0 %
Hydro + geothermal	105.5	110.6	112.3	118.9	124.0	127.5	0.7 %	0.5 %	0.6 %	0.4 %	0.3 %	0.4 %
Solar + wind + small hydro	2.4	11.2	18.7	32.5	56.1	73.2	24.6 %	18.6 %	5.7 %	5.6 %	2.7 %	4.7 %
Average load factor (%)	62.7	50.2	46.4	41.1	42.5	43.2	-3.1 %	-2.6 %	-1.2 %	0.3 %	0.2 %	-0.2 %
Fuel input for thermal power generation (million tonnes)	n.a.	292.7	291.4	299.7	365.1	416.3	n.a.	-0.1 %	0.3 %	2.0 %	1.3 %	1.2 %
Solids	n.a.	187.4	192.1	178.6	230.6	281.5	n.a.	0.8 %	-0.7 %	2.6 %	2.0 %	1.3 %
Oil	43.5	39.9	31.5	28.2	29.2	24.0	-1.2 %	-7.6 %	-1.1 %	0.3 %	-1.9 %	-0.9 %
Gas	32.9	65.4	67.8	92.9	105.3	110.9	10.3 %	1.2 %	3.2 %	1.3 %	0.5 %	1.7 %
Average thermal efficiency (%)	n.a.	35.8	37.6	42.4	44.5	46.6	n.a.	1.7 %	1.2 %	0.5 %	0.5 %	0.7 %
Final energy consumption	n.a.	n.a.	1059.6	1129.9	1197.7	1233.0	n.a.	n.a.	0.6 %	0.6 %	0.3 %	0.5 %
Solids	n.a.	n.a.	42.2	40.2	42.5	42.6	n.a.	n.a.	-0.5 %	0.5 %	0.0 %	0.0 %
Oil	n.a.	n.a.	538.4	554.7	576.6	579.5	n.a.	n.a.	0.3 %	0.4 %	0.1 %	0.2 %
Gas	n.a.	n.a.	240.6	266.0	268.3	260.7	n.a.	n.a.	1.0 %	0.1 %	-0.3 %	0.3 %
Heat	16.9	22.7	22.6	23.4	24.3	25.3	4.3 %	-0.2 %	0.4 %	0.4 %	0.4 %	0.4 %
Electricity	156.7	176.7	187.5	212.8	248.8	282.9	1.7 %	2.0 %	1.3 %	1.6 %	1.3 %	1.4 %
Renewables	n.a.	n.a.	28.4	32.7	37.1	41.9	n.a.	n.a.	1.4 %	1.3 %	1.2 %	1.3 %
by sector:												
Industry	345.1	350.8	359.1	375.9	386.1	383.0	0.2 %	0.8 %	0.5 %	0.3 %	-0.1 %	0.2 %
Transport	n.a.	296.5	309.8	336.2	357.8	371.7	n.a.	1.5 %	0.8 %	0.6 %	0.4 %	0.6 %
Domestic, tertiary and agriculture	340.5	374.4	390.7	417.8	453.8	478.3	1.4 %	1.4 %	0.7 %	0.8 %	0.5 %	0.7 %

Table 1.4: European energy balance summary from 1990 to 2030 (prospective (estimated) energy outlook) [77, IEPE/IPTS, 2000]

1.2 Economic situation

The process of deregulation and the opening-up of electricity markets is an ongoing worldwide phenomenon. The principle objective is to increase competition across the sector and thereby encourage the reduction of generation, transmission, distribution and supply costs to the benefit of both industrial and domestic consumers.

In parallel with the liberalisation of the electricity market there is a move towards the use of economic instruments to achieve national and international energy and environmental policy objectives. These instruments take various forms including taxes, incentives and market-based trading opportunities.

The opening-up of the European market began at the end of the 1980s, with the United Kingdom leading the way. Subsequently in 1996 the European Union introduced the Internal Electricity Market (IEM) Directive (96/92/EC), which required Member States to open-up up to 25 % of their markets to competition, although they remained free to take their market opening-up process even further. The degree of actual market opening varies throughout the EU, from a full open market in the United Kingdom, Germany, Spain, Finland and Sweden to a partially open market in other countries such as France and Italy.

The process of market development continues in a nationally determined stepwise process in Member States, even after full market opening. Disparities between national systems are due to the particular competition model a national government adopts, such as negotiated or third party access or the single buyer system. Consequently, the condition of regulations across Member States varies greatly on account of a number of factors. This is only to be expected, as the market structures evolved separately.

Cases of cross-border policy and technical alignment depend to a large extent on the size of the countries concerned, their history of co-operation with each other and indeed whether they are land-locked. The internal geography of a Member State can have a significant influence, simply due to the availability of natural resources and their physical impact on transmission grid systems. For example, in Sweden and Finland most hydropower generating capacity is in the north, so it supplies the more densely populated southern regions via long transmission lines, however nuclear stations are located in the south. Whereas in Germany, a hub-system model exists, arising from the heavy concentration of production plants in particular areas with the a consequent development of transmission systems from these areas.

A key objective of the IEM Directive is to open up domestic electricity markets to international competition. This requires significant changes to national systems. This can include privatisation, unbundling and the imposition of appropriate regulatory systems. In countries where vertically integrated utilities exert practically full control over electricity production, transmission and supply, then deregulation also provides opportunities for new entrants to penetrate the market and thereby stimulate competition.

A number of significant issues effectively impede full international competition. These include issues such as cross-border transmission pricing, the extent of overcapacity in some systems and bottlenecks in grid interconnection capacities between nations or states. Clearly it will take some time for international markets to develop to such an extent that genuine and widespread international competition exists.

As markets open up to competition, this can have a significant impact on a range of factors relating to the operation and regulation of large combustion plants, and which may be taken into account in determining the appropriateness of particular techniques to reduce emissions to air, water and land. The need for some plants to manage specific customer requirements including auxiliary services, such as maintaining voltage and frequency, leads to load following, peak load production and black start capability. These include, but are not limited to, the following: [58, Eurelectric, 2001].

- security of the energy supply. This can affect the levels of excess capacity in a system and the extent of fuel diversity, although the capacity is itself influenced by the need for spinning reserve and the availability of fuel storage
- cost of fuel
- the level of system security that is required by any given market can significantly influence factors such as the redundancy in plant design, with a direct influence on investment costs and the level of electricity price required to remunerate investment
- the impact of market shape (i.e. load duration curves), which together with factors such as the marginal cost of generation can influence the level of utilisation of particular types of plant, availability requirements and the level of excess capacity
- remuneration structures within particular markets, including whether they operate contract markets, balancing markets, trading via an electricity pool, capacity payments, etc.
- the level of the forward price within the market and the structure of price in relation to plant utilisation and generation costs, which may influence the ability of a given market to remunerate investments
- the extent to which tariffs in a particular market are fixed to control the supply or consumption of electricity produced by a given technique or sourced from a particular fuel, so as to support individual Member State energy policy requirements. Other instruments are also used by Member States to achieve these objectives, including carbon, energy and pollutant taxes
- the need for a particular plant to manage specific customer interface requirements, including ancillary services such as maintaining system voltage and frequency, load-following and load structure, black start capability and the specific need to meet local grid constraints, all of which can have a marked impact on the operational characteristics of such a plant
- the interaction of connected markets, such as in systems where gas and electricity grids create the opportunity for hedging between gas supply and electricity generation based on fuel price differentials, which can also be driven by short-term demand
- grid infrastructure and the particular charging structure within a specific market can have plant-specific implications, e.g. transmission loss, grid access and the use of system charges, together with the extent of constrained on or off running
- regulatory incentives within particular markets to encourage embedded and distributed generation. These can also have an influence on the level of renewable generation where national targets can be achieved through additional support mechanisms including supplier obligations or subsidies.

Location of combustion installations

It is general practice throughout Europe to locate fossil fuel-burning power generating plants in such a location to incur the minimum costs for installation and operation, allowing for a number of contributing factors related to the area where the plant is located and the infrastructure to support its operation. Each of these factors varies in significance according to local and national considerations, but in many cases the availability of a connection to the electricity transmission/distribution system, the proximity of the electrical demand, and the availability of water for the cooling systems, and the proximity of mining zones/seaports have often been predominant factors in selecting the location for large combustion plants. In the past, forecasts of future power demands for individual countries, and the optimum long-term costs for the preferred type of plant, have determined the chosen size and location of power generating plants.

Other factors are often of lower importance when selecting the location of a large combustion plant. The availability of suitable land, the visual and air quality impact on the local environment, and the access for the delivery and storage of fuels, are often factors that influence the design and positioning of a power generating plant. However, these factors are often considered in detail only when the general location has been determined, and do not usually override the decision to proceed with the plant installation.

With the widespread expansion of energy infrastructures taking place in Europe, there are also changes to the relative influence of each factors used when selecting the location of the power generating plant. It is now easier to bring the fuel and power connections to the right location for the plant, rather than to choose the location according to the existing infrastructure. The significant increase in the use of natural gas as a fuel has now resulted in a greater level of gas supply infrastructure, making gas more widely available at the pressure and quantity required for the operation of the gas turbines for power generation, with low transportation costs and no site fuel storage requirements. The expansion of the integrated electricity distribution system has widened the options for achieving good connections for the power generating plant to supply power into the system. New switchgear and control systems are also enabling more safe and effective connections.

There is an increasing availability of locations that meet the main requirements for power generating plants. At the same time, changes in power generating and abatement techniques have significantly increased the efficiency of power generation, as well as providing far cleaner exhaust gases than earlier plants burning fossil fuels. The use of gas turbines for power generation, and the development of new combustion plants and exhaust gas treatments have resulted in power plants that can use a range of gaseous, liquid or solid fuels, all emitting far less pollutants per unit of power generated than previously. Newer plants are frequently far smaller than older plants with an equivalent output, and building gas-fired plants avoids the need for land area for fuel storage. The overall impact that new plants have on their local environment is significantly less compared to older plants.

Additionally, following the recent changes and market opening of the European gas and electricity markets, long-term marginal costing to select plants is no longer appropriate, resulting in the increasing decision to build smaller plants, with higher efficiencies, lower capital costs and quicker build times.

Newer plants have higher generation efficiencies, which result, *inter alia,* in a reduced production of emissions (to water and air) per unit of power generated. Future increases of plant efficiency will not be unlimited because of

- the laws of thermodynamics
- the diminishing returns from increasing development costs
- increasing capital costs resulting in higher generation.

1.3 Key environmental issues

The operation of fossil fuel-fired combustion installations to generate electrical energy and/or heat, and in particular the electricity generating industry due to its large centralised power plants, is a very important cornerstone of our modern society and of the European economy. On the other hand, combustion installations use large amounts of fossil fuels and other raw material taken from the earth's natural resources, converting them into useful energy. These plants generate a number of residues, wastes and large amounts of emissions to all environmental media. To give an overview of the different mass streams, a generalised flow diagram of a combustion plant and its associated operations is presented in Figure 1.3.

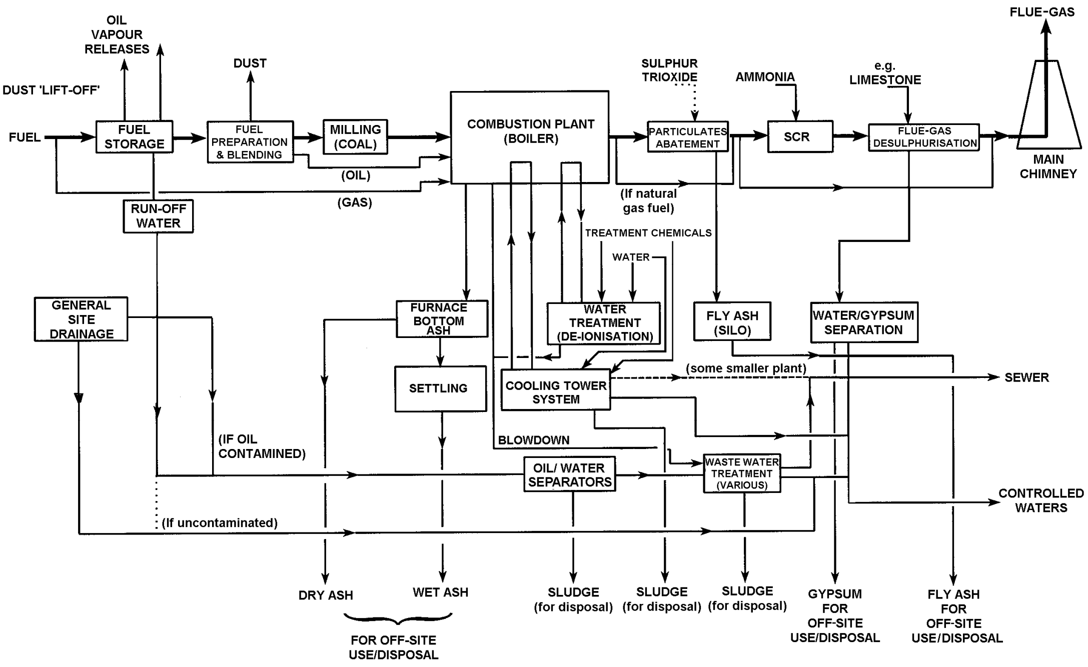


Figure 1.3: Generalised flow diagram of a combustion plant and its associated operations [5, HMIP, 1995]

Fossil fuels are the most abundant energy source used today. However, their burning results in a relevant and at times significant impact on the environment as a whole. The combustion process leads to the generation of emissions to air, water and soil, of which emissions to the atmosphere are considered to be one of the main environment concerns. The following sections give general information about the main substances emitted. An overview of the substances emitted, their sources and their influence on the different environmental media is given in Table 1.5.

SOURCE RELEASE Air (A) Water (W) Land (L)	Substances												
	Particulate matter	Oxides of sulphur	Oxides of nitrogen	Oxides of carbon	Organic compounds	Acids/alkalis/salts	Hydrogen chloride/fluoride	Volatile organic compounds	Metals and their salts	Chlorine (as hypochlorite)	Mercury and/or cadmium	PAHs	Dioxins
Fuel storage and handling	**A**				**W**			**A**					
Water treatment	**W**								**W**		**W**		
Exhaust gas	**A**	**A**	**A**	**A**	**A**		**A**	**A**	**A**		**A**	**A**	**A**
Exhaust gas treatment	**W**				**W**				**WL**		**W**		
Site drainage including rainwater	**W**				**W**								
Waste water treatment	**W**				**W**	**W**							
Cooling water blowdown	**W**				**W**				**W**	**W**	**W**		
Cooling tower exhaust								**A**					

Table 1.5: Potential emission pathways by source type and substance
[5, HMIP, 1995]

1.3.1 Efficiency

Prudent management of natural resources and the efficient use of energy are two of the major requirements of the IPPC Directive. Therefore, the efficiency with which energy will and can be generated now plays an increasingly important role as an indicator of the environmental impact of a process. Efficiency is not only important as a marker of the careful treatment of natural fuel resources, it is also an indicator of the emissions that are released in producing a unit amount of energy, emissions such as the so-called ‘climate relevant gases’ like CO_2. One way to achieve this benefit is by optimising the energy utilisation and the efficiency of the energy generating process. Optimising the specific efficiency depends on a variety of factors, including the nature and quality of fuel, the type of combustion system, the operating temperatures of the gas turbine and/or steam turbine, the local climate conditions, the type of cooling system used, etc.

Each sequential step in the process of fuel conversion to useful energy has its own efficiency factor. The overall efficiency of the process is achieved by multiplication of all the individual efficiency factors. The level and the comparability of the efficiency depend on the limits of the equipment chosen if necessary conversions have to be carried out (e.g. for the same reference temperature).

The net efficiency takes all losses into account due to: the auxiliary station supply (and process heat demand), fuel preparation, by-product treatment, flue-gas treatment, waste water treatment, the cooling system and fans and pumps. Efficiency optimisation can be achieved for all efficiency factors including any devices used for environmental protection. Stringent emission control enhances the auxiliary station supply, depending on the fuel and thus the product specific CO_2 emissions. For consumers of electricity, any grid and transformer losses have to be taken into account and, for consumers of heat from Combined Heat and Power (CHP) units, transport losses from district heating net and cycling pumps have be taken into account.

Periods of high ambient temperatures at the site decrease electricity production efficiency in both gas and steam turbines. For gas turbines and diesel engines, the ambient air temperature is more significant, whereas for steam turbines the temperature of the cooling media is more important. For the condensation of cooled expanded steam, there are three types of cooling system which can be applied: direct cooling with sea or river water, direct and indirect cooling with wet cooling towers, and indirect cooling with dry cooling towers. For more information, consult the ‘Industrial Cooling Systems’ BREF.

Efficiency and emissions

Even the most efficient power plants are currently passing a significant amount of their total energy input to the environment in the form of rejected heat. This heat may be absorbed in the local atmosphere or watercourses with relatively little harm to the local environment, but every unit of energy consumed represents additional CO_2 passed into the atmosphere. At the present time, the most effective way to improve the efficiency of power generation is to usefully use the heat produced, and not to throw it away.

For waste heat utilisation several thermodynamic, technical and economical criteria need to be taken into account. Thermodynamic criteria involve on one hand the temperature and on the other hand the resulting exergy-content of waste heat. The temperature has to be taken into account if the waste heat is to be used for heating. The exergy-content has to be taken into account if the waste heat is to be utilised for the production of electricity and power. The technical criteria depend on individual site conditions.

By reducing and utilising waste heat, generally energy can be saved, emissions can be reduced and resources can be preserved. There is now an increasing opportunity for power generating plants to be located at sites where the energy that is not converted to electricity can be passed as heat to users and consumers for their beneficial use. There are a wide range of processes that require continuous supplies of heat in the form of steam, hot water, or hot air as inputs to their production and operating facilities. This technique is known as cogeneration or combined heat and power production (CHP), and its associated heat consumption is usually at levels of between 70 and 90 % and it has the effect of increasing the overall combined efficiency of a power plant. The benefits of increased efficiency result in reduced emissions of CO_2, by avoiding the need for the heat consumer to burn fuel in a separate combustion plant. In many cases, there are also reductions in the overall emissions of nitrogen oxides (NO_X) and other pollutants, by replacing small unregulated combustion plants with heat from an adjacent power station. Nevertheless only technically and economically meaningful measures for both waste heat-reduction and waste heat utilisation will be able to meet both environmental and economic goals.

Effect of district heating on air quality

With regard to district heating boilers, which are typically located within or close to populated areas, the very beneficial effect of district heating on the local air quality should be pointed out. A few large and well maintained boilers with flue-gas cleaning and with high stacks can replace a large number of individual heating installations with low stacks and often poorly controlled combustion. As a result, the total emissions of particulates, CO and unburned hydrocarbons can be considerably reduced. With modern technology, there does not need to be any appreciable increase in SO_2 and NO_2 emissions either, even if the fuel quality in the district heating boilers is lower than that of the fuels it replaces in individual heating. With the same quantity of total emissions, the high stacks result in a higher degree of dilution before the pollutants reach the ground surface. The effect of this is that local air quality in the cities, towns and villages heated with district heating boilers is far better than it would have been if individual heating alone is used.

One example of the benefits of district heating, in terms of the improvement in energy efficiency, emission reduction and the environment, is a case study from the city of Helsinki (Finland). Here the application of district heating was initiated in the 1950s and is now close to saturation point with 92 % of all buildings connected to the district heating network. During the last decade, the partial substitution of coal for natural gas also contributed to a decrease in emissions. Some findings from the Helsinki energy supply study indicate an increase in electricity consumption and energy supply efficiency and a considerable decrease in specific emissions and measured SO_2 concentrations. In Helsinki, there has been a strong downwards trend in total SO_2 emissions over the past two decades, while the decrease in total NO_2 emissions only started a decade ago.

1.3.2 Emissions to air

The most important emissions to air from the combustion of fossil fuels are SO_2, NO_X, CO, particulate matter and greenhouse gases, such as CO_2. Other substances such as heavy metals hydrogen fluoride, halide compounds, unburned hydrocarbons, non-methane volatile organic compounds (NMVOCs) and dioxins are emitted in smaller quantities but may have a significant influence on the environment due to their toxicity or their persistence. Emissions of fly ash can also include emissions of particulate matter of aerodynamic diameters of less than 10 µm, called PM_{10}. Table 1.6 gives the contributions of various pollutant emissions from different LCP categories to the total emissions of these pollutants from IPPC installations operating in EU-15 in 2001.

LCP category	Contribution to total emissions from IPPC installations (%)										
	SO_2	NO_X	NH_3	CO_2	N_2O	CH_4	PM_{10}	Hg_{tot}	Dioxins+ furans	NMVOC	CO
LCPs over 300 MW	64.6	53.4	0.5	54.4	7.6	0.2	38.1	28.8	19.0	0.7	4.4
LCPs 50 – 300 MW	3.6	6.0	N1	5.0	21.0	0.2	2.1	2.6	0.2	0.7	2.8
Gas turbines	0.9	3.6	0.03	5.5	0.4	0.3	0.1	N1	0.3	0.1	0.3
Stationary engines	0.3	1.2	N1	0.1	N1	0.05	0.2	0.3	N1	0.1	0.03
All LCPs	69.4	64.2	0.5	65.0	29.0	0.8	40.5	31.7	19.5	1.6	7.5

Notes:
N1 No emissions reported for this category.

Table 1.6: Contributions of emissions from different LCP categories to the total air emissions from IPPC installations operating in EU-15 in 2001 according to the European Pollutant Emission Register 2001 (EPER)
[193, EC, 2001]

1.3.2.1 Sulphur oxides

Emissions of sulphur oxides result mainly from the presence of sulphur in the fuel. Fossil fuel contains sulphur as inorganic sulphides or organic compounds. For example, sulphur appears in coal as pyritic sulphur, organic sulphur, sulphur salts and elemental sulphur. During combustion, by far the majority of sulphur oxides are produced in the form of sulphur dioxide (SO_2).

For solid and liquid fuels, 3 to 4 % of the sulphur is also oxidised to sulphur trioxide (SO_3), with the presence of transition metals in the fuel catalysing this reaction. Sulphur trioxide is adsorbed on particulate compounds and, in the case of liquid fuels, contributes to the formation of acid soots. $PM_{10}/PM_{2.5}$ emissions are, therefore, increased by SO_3. Additionally 'blue smoke' can occur as an emission from boilers fired with heavy fuel oil. It is assumed, that this optical phenomenon is caused by sulphate formation (SO_2 plus dust) and enhanced by the vanadium content of the oil and probably also by the SCR catalyst.

Natural gas is generally considered free from sulphur. This clearly cannot be the case for certain industrial gases and desulphurisation of the gaseous fuel might then be necessary [4, OSPAR, 1997].

1.3.2.2 Nitrogen oxides (NO_X)

The principal oxides of nitrogen emitted during the combustion of fossil fuels are nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O). The first two of these form the mixture known as NO_X, which accounts for more than 90 % of the NO in the main types of large combustion installations.

The formation of NO_X is governed by three essential mechanisms; characterised by the origin of the nitrogen and the environment where the reaction takes place:

- thermal NO_X results from the reaction between the oxygen and nitrogen from the air
- fuel NO_X is formed from the nitrogen contained in the fuel
- prompt NO_X is formed by the conversion of molecular nitrogen in the flame front in the presence of intermediate hydrocarbon compounds.

The quantity of NO_X formed by the prompt NO_X mechanism is generally much smaller than that generated by the other reaction paths.

The formation of thermal NO_X highly depends on temperature. When combustion can be achieved with temperatures below 1000 ºC, emissions of NO_X are significantly lower. When the peak flame temperature is below 1000 ºC, the formation of NO_X mostly depends on the fuel nitrogen. The formation of thermal NO_X is the dominant pathway by which NO_X is generated in installations using gaseous or liquid fuels.

The formation of fuel NO_X depends on the nitrogen content of the fuel and the oxygen concentration of the reaction medium. The quantity of fuel NO_X produced is greater in installations using coal, as this has larger amounts of nitrogen in its structure than other types of fuel. The mean nitrogen content generally found in different types of fuel is given in Table 1.7.

Fuel	Fuel bound nitrogen (weight %, dry, ash-free basis)
Coal	0.5 – 2
Biomass (wood)	<0.5
Peat	1.5 – 2.5
Fuel oil	<1.0
Natural gas	0.0
Derived gases	0.1 – 1 (>>1 chemistry sources)

Table 1.7:Fuel bound nitrogen

The type of combustion process used also affects the amounts of nitrogen oxides emitted. In the case of coal, for example:

- NO_X emissions are lower with a moving grate boiler because of the relatively low combustion temperature and the progressive nature of the combustion as it advances over the grate
- emissions are higher in a pulverised coal boiler, varying with the type of burner and the design of the combustion chamber
- NO_X emissions in a fluidised bed boiler are lower than those produced in conventional boilers, but N_2O emissions are higher [4, OSPAR, 1997].

The formation of thermal NO_X is the dominant pathway by which NO_X is generated in installations using gaseous and distillate liquid fuels. The quantity of fuel NO_X produced is greater in installations using coal and heavy fuel oil, as these have larger amounts of fuel bound nitrogen.

The formation formed by the prompt NO_X mechanism is generally much smaller than that generated by the other reaction paths.

The formation mechanism of nitrous oxide (N_2O) has not yet been completely clarified. There is a possible formation mechanism based on intermediate products (HCN, NH_3), which is comparable to the formation of NO. It has been found that lower combustion temperatures, i.e. below 1000 ºC, cause higher N_2O emissions. At lower temperatures, the N_2O molecule is relatively stable; at higher temperatures, the N_2O formed is reduced to N_2. Compared to emissions from conventional stationary combustion units, nitrous oxide from either bubbling, circulating or pressurised fluidised bed combustion are relatively high. In laboratory experiments, it has been found that nitrous oxide is formed by ‘Selective Catalytic Reduction’ (SCR) processes, peaking at, or close to the optimum temperature ‘window’ of the SCR process. [1, Corinair, 1996]. Nitrous oxide (N_2O), also contributes directly to the greenhouse climatic effects though thermal infrared absorption in the troposphere. The tropospheric lifetime of N_2O is quite long, as its interaction with other gases, clouds and aerosols are minimal. N_2O is decomposed in the presence of O_3 and forms NO_2 and NO, noted as NO_X.

1.3.2.3 Dust and particulate matter

The dust emitted during the burning of coal, peat and biomass arises almost entirely from the mineral fraction of the fuel. A small proportion of the dust may consist of very small particles formed by the condensation of compounds volatilised during combustion.

The type of combustion process used has a considerable effect on the proportion of ash entrained in the flue-gas emissions from boilers. For example, moving grate boilers produce a relatively small amount of fly ash (20 – 40 % of total ash), whereas pulverised coal boilers produce an appreciable amount (80 – 90 %).

The combustion of liquid fuels is also a source of particulate emissions, although to a lesser extent than coal. In particular, poor combustion conditions lead to the formation of soot, which is liable to produce acid agglomerates with corrosive properties in the presence of sulphur trioxide.

The combustion of natural gas is not a significant source of dust emissions. On the other hand some industrial gases may contain particles which should be filtered out in the production process or, failing that, before combustion.

For many installations, there are also potential diffuse emissions (open-air handling and storage of coal, the crushing of the coal used in pulverised coal boilers, the handling of ash, etc.). [4, OSPAR, 1997].

Environmental problems can occur from particles less than 2.5 µm in diameter because they can remain suspended in the atmosphere for days or even weeks. Environmental problems can also occur by long time agglomeration of persistent compounds in the earth or by dilution and transfer to water bodies. The distance that particles travel before they are removed from the air by settling or by precipitation depends on their physical characteristics and the weather conditions. The size, density and shape influence the rate at which particles settles. Particles larger than 10 µm in diameter settle fairly rapidly. Their impact is primarily near the source. Smaller particles less than 10 µm and especially those less than 2.5µm can travel over hundreds of kilometres before settling. Aerosols often function as condensation nuclei for cloud formation and are washed out with rain.

Industrial emission control techniques for particulate matter (PM) are very efficient, achieving more than 99.8 % by weight removal from the raw gas input. Only for small particles, such as for PM_{10} and below, does the removal efficiency decrease to between 95 – 98 %. For this reason, the majority of particles from LCPs still emitted to the air are in the 0.1 µm to 10 µm diameter range.

1.3.2.4 Heavy metals

The emission of heavy metals, also known as trace metals, results from their presence as a natural component in fossil fuels. Most of the heavy metals considered (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn, V) are normally released as compounds (e.g. oxides, chlorides) in association with particulates. Only Hg and Se are at least partly present in the vapour phase. Especially Hg is known as a long-range transboundary pollutant which can create pollution problems in far distant areas from the emission source. Less volatile elements tend to condense onto the surface of smaller particles in the flue-gas stream. Enrichment in the finest particle fractions is, therefore, observed. Partitioning, for example, of heavy metals during coal combustion is shown below.

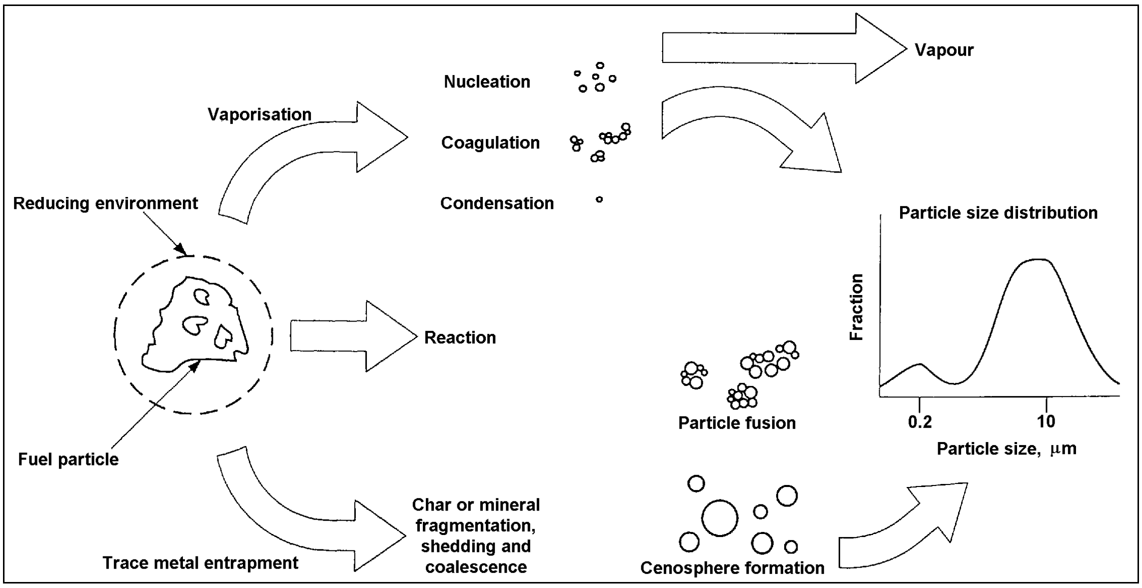


Figure 1.4: Partitioning of trace elements during coal combustion [107, Davidson, 2000]

The content of heavy metals in coal is normally several orders of magnitude higher than in oil (except occasionally for Ni and V in heavy fuel oil) or natural gas. Many of the heavy metals are chemically bound in compounds like oxides, sulphates, aluminosilicates and minerals such as anhydrites and gypsum. The leachability of the elements depends on the nature and particle size of the compound. During the combustion of coal, for example, particles undergo complex changes which lead to vaporisation of volatile elements. The rate of volatilisation of heavy metal compounds depends on the fuel characteristics (e.g. concentrations in coal, fraction of inorganic compounds such as calcium) and the characteristics of the technology applied (e.g. type of boiler, operating mode).

Table 1.8 gives some data for emissions of heavy metals from combustion installations in the EU-15 in 1990.

Source	Fuel	As (tonnes)	Cd (tonnes)	Cr (tonnes)	Cu (tonnes)	Hg (tonnes)	Ni (tonnes)	Pb (tonnes)	Zn (tonnes)
Total in the EU-15		**575**	**203**	**1170**	**3040**	**245**	**4860**	**1930**	**11100**
Stationary combustion (total of all three following sectors)		**491.8**	**57.8**	**397.5**	**390.1**	**89.6**	**2780.6**	**885.8**	**1597.8**
Combustion in energy production (including public power plants, cogeneration plants, district heating plants)	**All fuels (Total)**	**276.9**	**19.1**	**192.6**	**104.2**	**43.4**	**1681.5**	**190.5**	**395.4**
	Lignite	20.2	3.42	19.3	40.5	8.69	24	26.6	85
	Coal	130	4.42	40	42.1	21.2	94.4	105	219
	Fuel oils	117	10.2	132	19.9	1.39	1560	30.3	32.5
	Other fuels	9.73	1.06	1.36	1.72	12.2	3.05	28.6	58.9
Combustion in commercial, institutional and residential sectors (including boilers, gas turbines and stationary engines)	**All fuels (Total)**	**37.7**	**10.1**	**24.2**	**28.3**	**13.4**	**128.9**	**115.9**	**174.4**
	Lignite	2.02	0.483	0.89	0.325	4.2	15.5	21.5	0.284
	Coal	23.4	1.39	10.9	16.3	3.3	38.4	43	33.9
	Fuel oils	9.46	2.35	9	3.14	0.253	73	7.88	6.19
	Other fuels	2.82	5.91	3.42	8.53	5.61	1.94	43.5	134
Combustion in industry (including boilers, gas turbines and stationary engines)	**All fuels (Total)**	**177.2**	**28.6**	**180.7**	**257.6**	**32.8**	**970.2**	**579.4**	**1028**
	Lignite	65.6	8.95	62.8	140	13.7	80.7	81.4	219
	Coal	52.3	1.58	35.7	27.2	8.66	69.7	148	328
	Fuel oils	50.6	12	69.5	43.5	1.53	805	199	148
	Other fuels	8.72	6.07	12.7	46.9	8.94	14.8	151	333

Table 1.8: Annual emissions of heavy metals from combustion installations in EU-15 in 1990
Data taken from the European Emission Inventory of Heavy Metals and Persistent Organic Pollutants for 1990, [10, Berdowski, et al., 1997]

1.3.2.5 Carbon monoxide

Carbon monoxide (CO) always appears as an intermediate product of the combustion process, particularly in understoichiometric combustion conditions. Plant operators always try to minimise CO formation, as CO is an indicator of corrosion risk and unburned fuel, and therefore signifying a loss of efficiency. The formation mechanisms of CO, thermal NO and VOC are all similarly influenced by combustion conditions [1, Corinair, 1996].

1.3.2.6 Greenhouse gases (carbon dioxide and others)

Since the beginning of industrialisation, the energy balance of the earth has been changing due to the increasing emissions of anthropogenic greenhouse gases, mainly carbon dioxide (CO_2). Due to the accumulation of CO_2 in the atmosphere over the last two centuries, the amount of infrared radiation trapped in the atmosphere has increased. At the same time, a considerable increase in the global mean temperature[1] and CO_2 concentrations in the atmosphere have been observed, as shown in Figure 1.5. and Figure 1.6.

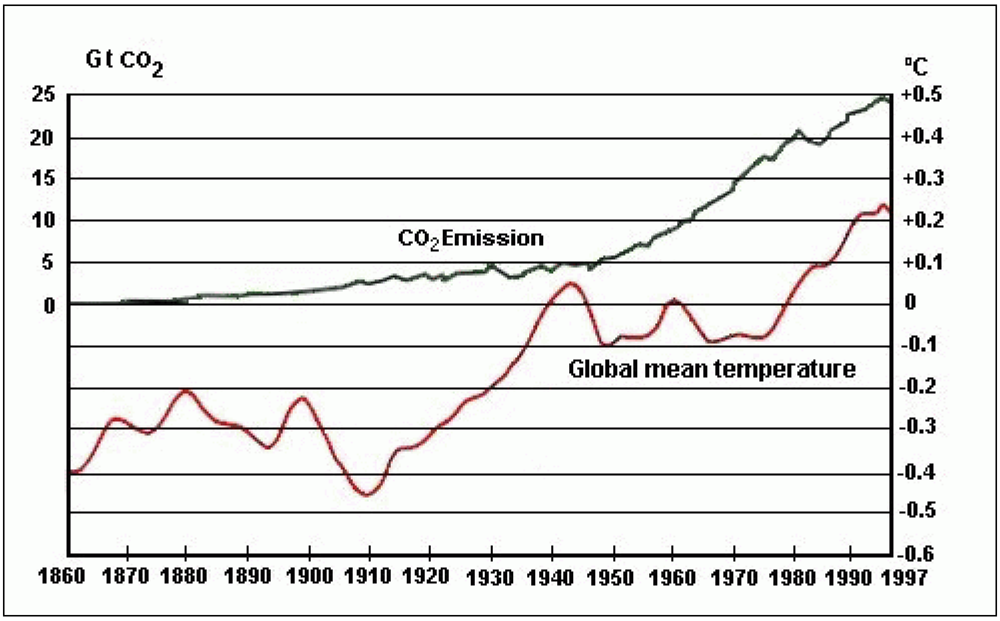


Figure 1.5: Global mean temperature and amount of CO2 emitted over the past century [13, Verbund, 1998]

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[1] Between 1856 and 1998, the yearly deviations from the 1961 - 1990 global average and European temperature show an increase of 0.3 °C to 0.6 °C. 1998 was globally the warmest year on record, and 1997 the warmest before that. This is partly due to the 1997/1998 El Niño/Southern Oscillation (ENSO), which was the largest on record (Hadley Centre/The Met. Office, 1998a). The ENSO phenomenon is a cycle of natural fluctuations of Pacific ocean temperatures resulting in large-scale changes in tropical rainfall and wind patterns [11, EEA, 1999].

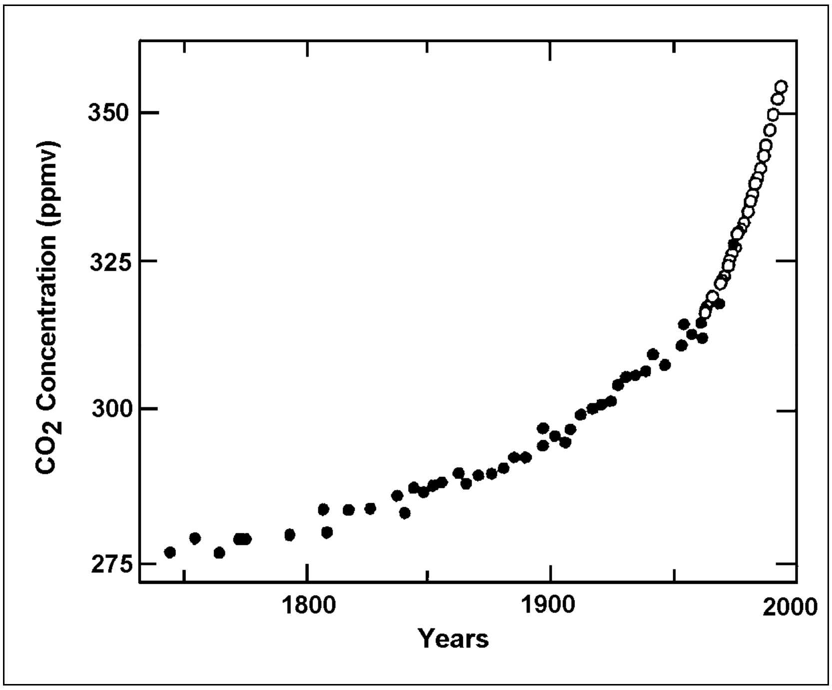

Figure 1.6: Change in CO_2 concentrations in the atmosphere over time

It is thought that the rise in the global mean temperature due to the increased atmospheric concentration of greenhouse gases will change the earth's climate if the emission of such gases (mainly CO_2) is not reduced.

The only important greenhouse gases from the combustion of fossil fuels in large combustion plants are carbon dioxide (CO_2) and nitrous oxide (N_2O). Carbon dioxide (CO_2) released by large combustion plants is responsible for approximately one third of the world's global CO_2 emissions. A number of scientists also expect natural influences such as sunspots/cosmic particles, geological things and, in particular, the increasing amount of water vapour in the atmosphere as additional reasons for global warming. Table 1.9 shows the estimated contribution of greenhouse gases to global warming (data have been taken from [14, EEA, 1999]).

Gas	Concentration increase since about 1750	Contribution to global warming [1]	Main anthropogenic source
CO_2	30 %	64 %	Fossil fuel combustion (includes energy generation and transport)
			Deforestation and land use
			Cement production
N_2O	15 %	6 %	Use of fertilisers
			Land clearing
			Adipic and nitric acid production
			Biomass burning
			Fossil fuel combustion (FBC)

Notes:
1 To compare the impact of different gases, the global warming potential (GWP) relative to CO_2 is often used, with CO_2 having the value of 1. GWP is a concept that takes into account the energy absorption capacity of the gas and its lifetime in the atmosphere. GWP should always be quoted for a specific time period. Examples of GWP values over a 100 year period are 21 for CH_4, 310 for N_2O and several thousands for a number of halogenated compounds. The emissions that take GWP values into account are called CO_2 equivalents.

Table 1.9: Greenhouse gases: concentration changes, contribution to global warming and main sources
[12, IEA, 2001]

Carbon dioxide (CO_2) is the main reaction product from the combustion of all fossil fuels. The CO_2 emission is directly related to the carbon content of fuels, where gaseous fuels have significantly lower CO_2 emissions than other fossil fuels. The content of carbon varies for coal and lignite (hard and brown coal) between 61 and 87 wt-%, for wood it is about 50 wt-%, and for gasoil and heavy fuel oil about 85 wt-% [1, Corinair, 1996]. Table 1.10 presents the specific CO_2 emission factors for the main fuels burned in large combustion plants.

Fuel	Specific CO_2 emission factors as a range. (t CO_2/TJ (g/kWh))
Natural gas	55 (198)
Heavy fuel oil (HFO)	80 (288)
Light fuel oil (LFO)	77 (277)
Hard coal	95 (342)
Lignite	110 (396)

Table 1.10: Specific CO_2 emission factors for the main fuels burned in large combustion plants [192, TWG, 2003]

Figure 1.7 presents the CO_2 releases calculated as kg CO_2/MWh electricity produced for different types of combustion plants [133, Strömberg, 2001].

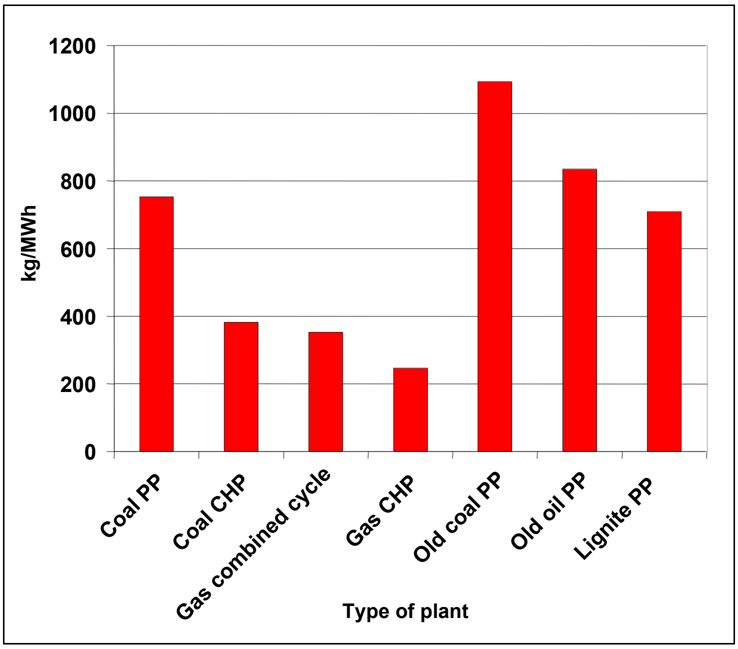

Figure 1.7: Examples of CO_2 releases for different types of combustion plants
Note: calculated as kg CO_2/MWh electricity produced
[133, Strömberg, 2001]

EU CO_2 emissions decreased by 1 % between 1990 and 1996, although the trend varies considerably between Member States. The decrease for the EU as a whole depends strongly on reductions in Germany and the United Kingdom. Germany has the largest national CO_2 emission in the EU, with approximately 30 % of the EU total in 1995. Between 1990 and 1996 the largest absolute emission reduction took place in Germany, mainly caused by the economic restructuring of the former German Democratic Republic. The substantial reduction in emissions in the United Kingdom was mainly caused by the change-over of fuel switching from coal to natural gas [14, EEA, 1999]. Table 1.11 gives information about the greenhouse gas emissions and the removals/sinks for CO_2 in the 15 European Member States (EU-15). For more detailed data about the emissions of greenhouse gases in the European Community consult the Annual European Community Greenhouse Gas Inventory 1990 – 1996 [14, EEA, 1999] (http://www.eea.eu.int/).

Member States	CO_2 (million tonnes)		CH_4 (kt)	N_2O (kt)
	Emissions	Removals/Sinks		
Austria	62	14	580	13
Belgium	129	2	591	35
Denmark	60	1	430	33
Finland	66	14	270	18
France	399	60	2844	174
Germany	910	30	4788	210
Greece	92	-	457	29
Ireland	35	6	800	26
Italy	448	36	2516	162
Luxembourg	7	0	24	1
Netherlands	185	2	1179	72
Portugal	51	1	834	14
Spain	248	29	2370	90
Sweden	63	32	297	10
United Kingdom	593	19	3712	189
EU-15	3347	247	21692	1076

Notes:
Estimates for 1996 were not available for Austria, Denmark, France, Italy, Portugal and Spain. For these countries 1994 and 1995 estimates have been used for a preliminary EU-15 1996 estimate. The CO_2 estimates are not corrected for temperature or electricity trade. Some Member States use corrected CO_2 estimates to better reflect national circumstances.

Table 1.11: Greenhouse gas emissions and removals/sinks in 1996
[14, EEA, 1999]

1.3.2.7 Hydrochloric acid

Large combustion plants without flue-gas desulphurisation (FGD) are recognised to be a major source of hydrogen chloride to the atmosphere. The emission of hydrochloric acid is due to trace amounts of chloride present in fossil fuels such as coal and oil. When fossil fuels are burned, small amounts of chloride are released. Some of that chloride then combines with hydrogen to form hydrogen chloride. Together with the moisture in the air, hydrogen chloride transforms to a hydrochloric acid aerosol that contributes to acidification problems. This becomes more dilute as it moves through the atmosphere.

1.3.2.8 Hydrogen fluoride

Like chloride, fluoride is also a natural element present in fossil fuels. When using fossil fuels such as coal for generating energy without using FGD, fluoride is liberated and released to the flue-gas. It combines with hydrogen to form hydrogen fluoride, and with the moisture of the ambient air to form hydrofluoric acid. It has been observed that hydrogen fluoride may be emitted by carry-over from the rotating heat-exchanger and combustion air preheater.

1.3.2.9 Ammonia (NH_3)

The emission of ammonia (NH_3) does not result from the combustion of fossil fuels, but rather the consequence of an incomplete reaction of ammonia in the denitrification process. Ammonia is used as an additive as pure ammonia or in solution with water in SCR and SNCR units. Ammonia chemically reacts to form NH_4HSO_4 and is mainly removed together with the fly ash from the system. With no dust removal or FGD downstream DENOX (tail end configuration) the 'ammonia slip' is then emitted along with the flue-gas to the atmosphere. The ammonia slip at SCR and SNCR installations increases with an increasing NH_3/NO_X ratio, but also with decreasing catalyst activity.

1.3.2.10 Volatile organic compounds (VOC)

The emission sources of volatile organic compounds due to industrial activities are numerous, with the combustion of fossil fuels being one of the most significant.

1.3.2.11 Persistent organic compounds (POPs), polycyclic aromatic hydrocarbons (PAHs), dioxins and furans

Among the persistent organic compounds liable to be emitted during the combustion of fossil fuels, polycyclic aromatic hydrocarbons (PAHs), polychlorodibenzo-dioxins (PCDDs) and polychlorodibenzo-furans (PCDFs) should be mentioned.

PCDD and PCDF molecules are not very volatile and, when adsorbed on particles produced by combustion, they have a high thermal and chemical stability in the environment. They can only be destroyed above temperatures of 1000 ºC. In this context, it should be noted that PCDD/PCDF are not only found in the stack gases but they are also found in the solid residues from any combustion process, such as in bottom ashes, slags, and fly ash.

There are 75 congeners for dioxins and 135 for furans. In order to quantify dioxin and furan emissions by taking into account their toxicity, the concentration or emitted flux is weighted by a coefficient (the Toxic Equivalency Factor TEF) characteristic of each of the molecular forms of PCDD/PCDF found in the mixture in question[2]. 2,3,7,8-tetrachlorodibenzodioxin is reputedly the most toxic PCDD and is taken as a reference substance, being given by convention a TEF value of 1. The other congeners considered to be worrying are 2,3,7,8 substituted molecules.

The dioxin activity of a mixture is expressed by its TEQ (Toxic Equivalent Quantity) defined by:

$$\text{TEQ} = \Sigma\text{isomers x TEF}$$

Besides the combustion of coal, combustion installations using wood are also mentioned as a possible source of emissions. The main process involved is the recycling of wood for power production, for example in the form of chipboard or of waste from wood that has been treated or that includes chlorinated organic compounds (PCP, lindane, PVC, NH_4Cl, etc.). Moreover, the introduction of a combined combustion of waste (sewage sludge, plastics and others) in certain conventional combustion installations could also lead to significant emissions of dioxins [4, OSPAR, 1997].

1.3.3 Emissions to water

Besides the generation of air pollution, large combustion plants are also a significant source of water discharge (cooling and waste water) into rivers, lakes and the marine environment. These discharges may cause water quality problems, which vary widely, depending on the type of fuel used, the abatement technique applied, the cooling technique and consequently the amount of water used, and the chemical and biological treatment reagents added for cleaning and maintenance purposes. The main sources of effluent streams in a fossil fuel fired combustion plant can be classified as follows:

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[2] The TEF values for the various PCDD/PCDF molecules differ according to the system used. However, the NATO-CCMS (NATO Committee on the Challenges of the Modern Society) system is commonly used internationally.

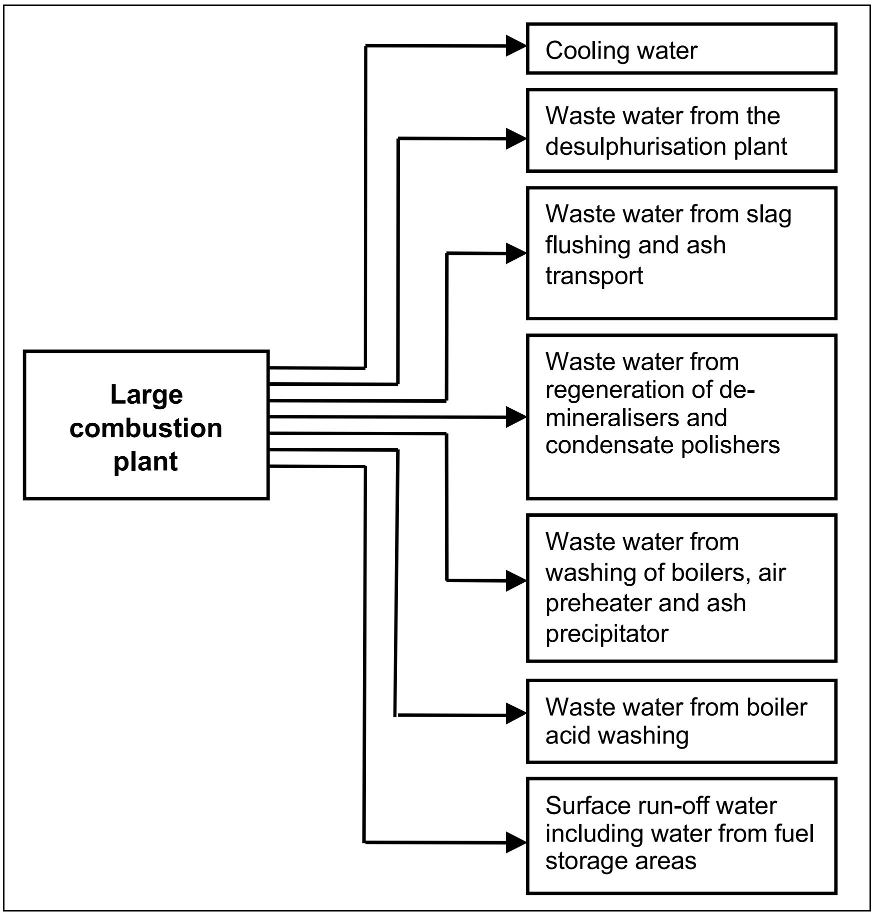


Figure 1.8: Effluents from fossil fuel fired large combustion plants

The thermal efficiency of a combustion cycle is restricted by the thermodynamic limits of the ‘Carnot-cycle’, which is the ideal combustion cycle. This means that not all the chemically bound energy of a fossil fuel can be transformed into mechanical energy and further onwards into electrical energy. The result is that a significant portion of the energy provided by combustion must be dissipated at the condenser level and transferred to the surrounding environment as a heat discharge. Many combustion plants use large amounts of cooling water as a cooling medium, which they take either from rivers, lakes, groundwater bodies or the sea.

The waste heat is transferred (by using cooling techniques such as once-through systems or wet cooling towers) into the cooling water and, further, to the aquatic environment. The environmental impact of industrial cooling, and thus also of cooling techniques used in large combustion plants are described in the BREF on the application of BAT to industrial cooling systems.

The waste water streams mentioned above can be contaminated by a variety of different water polluting substances. The following table shows the generally relevant polluting parameters, which are of concern as emissions of LCPs to water. However, the significance of each parameter depends on the quality of the raw water, on the specific plant configuration and the processes applied, which also determines the type and amount of pollutant present in waste water prior to treatment. The contents of Table 1.12 do not fully apply to gas and liquid fired power plants.

Parameter	Parameter*
pH	TOC
Temperature	N (total)
Colour	P (total)
TSS	Cd
TDS	Cr
BOD	Cu
COD	Hg
Mineral oils	Ni
Free chlorine	Pb
NH_3	Zn
Fish toxicity	Cl^-
Sb	F^-
As	PAH
Co	BTEX
Mn	
Tl	
V	
Sn	
CN	
S	
SO_3	
SO_4	
EOX	
Phenol	
PCDD/PCDF	
* according to the Commission Decision 2000/479/EC on the implementation of EPER: sector-specific sub-list for combustion installations >50 MW_{th}, as foreseen in the draft guidance document on EPER implementation (23/8/2000).	

Table 1.12: List of water pollutants from large combustion plants

Because of their chemical, biological and physical behaviour, such compounds may have a high impact on the aquatic environment. These substances can cause changes in the receiving water, such as increasing its acidity or alkalinity thereby changing its pH value, salinity, reducing its oxygen content and increasing plant growth due to the emission of plant nutrients.

For instance, water from slag flush and ash transport has an alkaline character due to the composition of the ash, whereas water from boiler washing is acidic. Waste water from the wet desulphurisation plant contains salts such as chlorides and sulphates. Salt derived from the sea is found in most coastal waters. However discharges from industrial activities such as energy generating facilities provide a further source of salt, this effect is even more significant if the water is discharged to a river or lake.

1.3.4 Combustion residues and by-products

The combustion of fossil fuels is associated with the generation of a variety of residues and by-products. The term by-products will generally be used for materials which can be sold on the market (e.g. gypsum from flue-gas desulphurisation) According to their origin, residues from a combustion plant can be divided into waste directly related to the process of combustion or waste generated by the operation of the plant and its equipment such as coal mills or water treatment facilities. Residues directly related to the process of combustion of fossil fuels are ashes (fly and bottom ash) and residues that are generated by the desulphurisation of flue-gases: Within the EU about 55000 kt of solid waste was produced from coal combustion. For instance, in 1999 about 31000 kt was utilised (55.3 %). The remaining 24000 kt was disposed of.

- **bottom ash and/or boiler slag:** Bottom ash is non-combustible material that settles to the bottom of the boiler and remains in the form of unconsolidated ash. If combustion temperatures exceed the ash fusion temperature, the ash remains as slag in a molten state until it is drained from the bottom of the boiler as boiler slag

- **fluidised bed ash:** The operation of a fluidised bed combustion installation for a solid fuel such as coal but also for burning biomass and peat is related to the generation of ash, which is a composition of spent bed material and fuel ash. Ash is removed from the bottom of the fluidised bed combustion chamber

- **fly ash:** Fly ash represents the part of the non-combustible material that is carried out of the boiler along with the flue-gas. Fly ash is collected from the particulate control equipment, such as from the electrostatic precipitator or bag filter, and also from different parts of the boiler, such as the economiser and the air preheater. The largest amount of ash is generated by the combustion of coal and lignite, followed by the combustion of peat and biomass, whereas gas-fired facilities generate very low quantities of ash. The amount of ash generated from a liquid fuel fired facility is much higher than from a gas-fired boiler, but compared with the amount of ash from coal combustion, the quantities are rather small

- **flue-gas desulphurisation residues and by-products:** Fossil fuels such as coal, peat and oil contain varying amounts of sulphur. To avoid high emissions of sulphur dioxide to the atmosphere, large combustion plants (in particular plants over 100 MW_{th}) are usually equipped with flue-gas desulphurisation plants (FGD). The different desulphurisation techniques currently in use result in the generation of a number of residues and by-products. Wet lime/limestone scrubbers, for instance, produce gypsum as a by-product, whereas dry scrubber systems produce a mixture of unreacted sorbent (e.g. lime, limestone, sodium carbonates, calcium carbonates), sulphur salts and fly ash as residue.

Ash and flue-gas desulphurisation residues are by far the largest quantities of waste from large combustion plants. These residues are partly discharged to a landfill or can be used for different purposes such as an additive in cement and concrete production; an aggregate in concrete, asphalt, mine reclamation or waste stabilisation; and as an ingredient in many other products.

Gypsum, a by-product from the desulphurisation plant, is largely used in the production of gypsum board, and makes a significant and increasing contribution towards the demand for gypsum. However, a certain contribution is also made by natural gypsum.

Beside the waste that is directly related to the combustion process wastes and which arises in large volumes, lower volume wastes are generated as a result of plant and equipment operation. Typical examples of such wastes are:

- **residues from boiler cleaning:** Residues generated during the maintenance of the gas and water side of the boiler, including the air preheater, economiser, superheater, stack, condenser and ancillary equipment. On the gas side, combustion residues such as soot and fly ash, build up on the surface of the equipment and must be removed periodically. On the water side, scale and corrosion products build up in the boiler and need to be removed from time to time by using acid or alkaline solutions

- **rejects from solid fuel milling:** Solid fuels such as coal and lignite are normally reduced in size in order to be able to blow them into the boiler. During the milling of coal, any rocks and pyrites (an iron-based mineral) need to be separated from the fuel stream. This solid residue may be discharged together with the bottom ash

- **make-up water treatment sludge:** Wastes resulting from the treatment of make-up water for the steam cycle. The treatment of boiler make-up water may include different processes such as settling, flocculation, softening, filtration and osmosis. These treatment methods result in the generation of treatment sludge

- **spent ion-exchange resins:** Ion exchange resins are used for the treatment of boiler make-up water

- **spent catalysts from SCR processes:** SCR catalysts are used to reduce nitrogen oxide emissions to the atmosphere. Due to deactivation, these catalysts have to be replaced periodically (after several years of service). Today, different processes exist for the regeneration of such catalytic materials

- **waste water treatment sludge:** Sludge generated by treating the different waste water streams from a large combustion plant

- **laboratory waste:** Small amounts of waste generated in the laboratory, for instance by analysing fuel samples, intake water, by-products, residues, etc.

- **other residues:** Other residues include those resulting from used oil and equipment containing oil, equipment containing PCB, and waste from the treatment of fuel (e.g. coal washing).

Most of the above-mentioned residues and by-products, from both the combustion process (e.g. ash) and from the desulphurisation process (e.g. gypsum), and any other residue from the combustion plant generally represent a potential environmental risk. Ash from a coal-fired boiler, for instance, contains elements such as silicon, aluminium, iron, calcium, magnesium, potassium, sodium and titanium, as well as heavy metals such as antimony, arsenic, barium, cadmium, chromium, lead, mercury, selenium, strontium, zinc and other metals.

Current EU legislation regards many of the above-mentioned residues from combustion plants as wastes. However, for many decades industry has put great effort into developing ways to minimise the generation of residues and/or to re-use them in various industry sectors, such as in the cement and construction industry, so that the quantities of waste destined for landfill have actually been reduced. According to Council Directive 75/442/EC (and its modifications), this is beneficial to the environment because the utilisation of residues as raw materials helps to conserve natural resources and to minimise the total amount of wastes that have to be discharged.

With respect to bottom and fly ash from coal combustion, both are composed of various elements from soil associated with the coal. One of their most distinctive characteristics is that the bulk of this material is in a powdered or sintered state, with most of the elements contained within a glassy matrix, and this basically determines their legal classification in national and international waste lists as an inert, inactive or non-hazardous residue (e.g. non hazardous wastes in the European list of wastes - Decision 2001/118/EC, and also forms part of the ‘green’ list of the OECD Decision C(92)39/final).

It is also well known that some by-products, such as gypsum from the desulphurisation plant, (gypsum has been classified as non-hazardous in the European list of wastes (Decision 2001/118/EC)) have a strong commercial share of the gypsum market and are used as the most important raw material for the production of gypsum boards. These efforts made by industry help to reduce cross-media effects and the risk of environmental damage.

1.3.5 Noise emissions

Noise and vibration are common issues arising from the operation of large combustion plants, especially as gas turbines have the potential for high noise emissions. Process noise emitted from an installation into the surrounding environment is a factor that has caused many complaints in the past and some information needs to be given about causes and approaches to prevent and minimise noise and vibration.

The most significant sources of noise are from the transport and handling of fuels, residues and by-products; the use of large pumps and fans; safety valves; the cooling technique; and of course from boilers, steam and gas turbines or stationary engines. Noise and vibration can be measured in a number of ways, but generally the detail is site-specific and takes account of the frequency of the sound and the location of residential areas (sensitive receptors).

The impact of noise emitted from a combustion plant is limited to a relatively close area around the installation. The most frequent problem, especially during the night, can be noise nuisance to people living in the area close to the plant. For this reason in some countries, the noise levels during the night are more stringent.

1.3.6 Emission of radioactive substances

According to Article 2.1 of the IPPC Directive, natural radioactive substances are not considered to be substances covered by the IPPC Directive. However, it has been agreed within the technical working group on large combustion plants to include some information on the emission of natural radioactive substance released by the combustion of fossil fuels in the general part of this document.

However, emissions of radioactive substances naturally present in most fossil fuels are not considered to be a key environmental issue within the scope of the exchange of information on BAT for large combustion plants, and will, therefore, not be further described. Nevertheless, over recent years, European society (especially people living close to large combustion plants) has become increasingly wary about radiation releases from the utilisation of fossil fuels, in particular the combustion of large amounts of coal. However in practice, air emissions of radioactive substances from a particular power plant or stack, have been found to be close to undetectable in comparison with natural background radiation.

The reason for this is that after the combustion of coal, lignite or peat, most of the radioactive substances remain in the ash. An examination of the radioactivity of solid material passing through power plants has shown that more than 90 % of the radioactivity in coal is retained in the ash. Only a small percentage of the radioactivity can be found in flue-gas desulphurisation products such as FGD gypsum. Radionuclide concentration in an ash is determined by the radionuclide concentration of the coal, the ash content of the coal and the conditions at the power station. Because of the ash content, natural radioactive nuclide concentrations in fly ash exceed that in coal by a factor of 2 to 15. International measurement results of radioactive activity in the fly ash produced by coal burning range between 60 and 1000 Bq/kg. Mean data values range from 90 to 180 Bq/kg with peak values of up to 1000 Bq/kg for the uranium series, and from 70 to 150 Bq/kg with peak values of up to 290 Bq/kg for the thorium series.

Peat ash is used as a landfill, for landscaping, in concrete, and as a bulk material for road construction. It may also be taken to dumps or mounded. The radiation exposure from the handling and utilisation of peat ash has been estimated with activity indices. In peat ash, the activity concentrations of radionuclides are 20 – 25 times higher than in peat itself. The concentrations of radium and thorium are of the same magnitude as those in soil and rock. The concentration of uranium (up to 1000 Bq/kg) is on average about 25 times higher than that in sand and gravel.

2 COMMON TECHNIQUES FOR ENERGY GENERATION

2.1 Principles of combustion

A boiler requires a source of heat at a sufficient temperature to produce steam. Fossil fuel, when used for the generation of steam, is generally burned in the furnace or combustion chamber of the boiler. Steam generators might also use thermal energy in the form of waste heat from another process.

Combustion can be defined as the rapid chemical combination of oxygen with the combustible elements of a fuel. There are just three combustible chemical elements of significance carbon, hydrogen and sulphur. Sulphur is usually of minor significance as a source of heat.

Carbon and hydrogen, when burned to completion with oxygen, are transformed to CO_2 and H_2O according to the following reactions:

$$\mathbf{C + O_2 \rightarrow CO_2}$$
$$\mathbf{2H_2 + O_2 \rightarrow 2H_2O}$$

Air is the usual source of oxygen for boiler furnaces. These combustion reactions are exothermic and the heat released is about 32800 kJ/kg of carbon burned and 142700 kJ/kg of hydrogen burned. The energy of the fossil fuels cannot be calculated by the sum of energy from the hydrogen and carbon content alone, as the chemical energy of molecular formation also needs to be taken into account. Also sulphur and other elements in the fuels contribute to the energy release. As water is released in a gaseous form during combustion, the water content of the fuel reduces the heat transferable to the steam generator. This energy is expressed as the 'lower heating value' (LHV). The LHV can be compared to the 'upper heating value' (UHV) which is defined for all the combustion products at environmental conditions (1 bar, 25 °C). Most of the additional energy is only available with condensation of gaseous H_2O from the flue-gas to liquid H_2O at heat temperatures below the water dew point, i.e. less than 40 °C.

The objective of good combustion is to release all of this heat whilst minimising losses from combustion imperfections and superfluous airflows. The combination of the combustible elements and compounds of a fuel with the oxygen requires a temperature high enough to ignite the constituents, good mixing or turbulence, and sufficient time for complete combustion.

In a boiler furnace (where no mechanical work is carried out), the heat energy derived from the reaction of combustible elements with oxygen depends on the ultimate products of combustion and not on any intermediate combinations that may occur in reaching the final result.

A simple demonstration of this law is the reaction of 1 kg of carbon with oxygen to produce a specific amount of heat. The reaction may all occur in one step to form CO_2, or under certain conditions, it may be occur in two steps: firstly forming CO, which produces a much smaller amount of heat, and secondly, through the reaction of the CO to form CO_2. However, the sum of the heat released in the two steps is the same as the 32800 kJ/kg evolved when carbon is burned in the single step to form CO_2.

The fact that carbon can react in these two ways with oxygen is of the utmost importance in the design of combustion equipment. Firing methods must assure complete mixture of the fuel and oxygen to be certain that all of the carbon burns to CO_2 and not to CO. Failure to meet this requirement will result in appreciable losses in combustion efficiency and in the amount of heat released by the fuel, since only about 28 % of the available heat in the carbon is released if CO is formed rather than CO_2.

2.2 Common technical combustion processes

The chapter is designed for those interested in gaining a general understanding of the industry and for those interested in the interrelationship between industrial processes and the topics described in subsequent sections.

2.2.1 General fuel heat conversion

In this section, information is only given as a summary to provide an overview of different combustion techniques. Where necessary, the specific combustion processes are given in more detail in the relevant fuel chapters. Combustion techniques are generally applied at about atmospheric pressure, but can be developed for higher pressure. In all combustion systems, fuel energy (net calorific value) is converted close to 100 % to heat. This conversion efficiency is called ‘fuel utilisation’ and limits the overall efficiency of all processes.

Generally in most applications, this released net fuel heat is transferred to, and applied in, steam processes. The unburned carbon in ash, CO, and VOC, contain the losses of fuel energy during the combustion process.

In gasification processes for solid or liquid fuels, heat is released in two steps; first step is when the fuel is gasified and the second step is when product gas is burned. In pressurised systems, all the released heat can be directly applied to gas turbines or combustion engines after gas cleaning.

Extraction of special gaseous (or liquid) fuels leads to specific products, dealt with, i.e. in refineries and not in LCPs.

The choice of system employed at a facility is based on the loads, the availability of the fuels, and the energy requirements of the electric power generation facility. Facilities using these systems also need other ancillary processes to be performed to support the generation of electricity. These ancillary processes might include supporting operations such as, e.g. coal processing and pollution control. [21, US EPA, 1997].

2.2.2 Pulverised solid fuel firing

In more than 90 % of capacity of solid fuel combustion systems the fuel is pulverised before combustion. Two general lines are possible:

- **dry bottom ash furnace:** This type operates at temperatures far below the melting point of the ash with respect to ash quality. To avoid slagging, the ash temperature should be low enough not to stick to the wall, and ash collected at the bottom stays solid. More detailed information is given for coal combustion systems in Chapter 4.

- **slag tap furnace:** This type operates at temperatures above the melting point of the ash to ensure liquid ash with sufficient fluidity to flow down the protected walls. The liquid ash is quenched in a water filled collector. This type is often used for fuels with poor combustion characteristics and involves recycling the fly ash. The co-combustion of wastes is often easier in slag tap furnaces. More detailed information is given for fuel specific combustion systems in Chapter 4.

2.2.3 Fluidised bed combustion furnace

For this FBC type of furnace, solid fuel generally has to be coarsely milled. Fine particulates would be blown out of the fluidised bed, large particulates would stop fluidisation.

Small units operate at atmospheric pressure and static fluidisation. With growing boiler size, the application of circulating fluidised bed combustion is preferred. To utilise the whole furnace, volume particulate extraction, cyclone separation and the recycling of coarse particles to the bed is an integral part of the concept. A few pilot FBCs plants are operating at higher pressures integrating a gas turbine for flue-gas expansion. These systems are called PFBC. PFBC technology is still under development. More detailed information is given for coal or biomass combustion systems in Chapter 5.

2.2.4 Grate firing

In grate firing, the fuel used should be of smaller dimensions than the grate system. Fuel particles that are too small fall unburned through the grate, particles that are too large are not fully burned out when leaving i.e. a moving grate. More detailed information is given for coal or biomass combustion systems later.

2.2.5 Oil and gas firing

Oil and gas firing systems formed the basic design for pulverised fuel combustion. Whereas gaseous fuel is directly combusted with air, liquid fuels are sprayed into the furnace via nozzles, generating very small droplets atomised by high pressure steam and producing a high amount of volatiles. Only heavy fuel oils have significant amounts of ash. All clean gaseous and liquid fuels can be fired by burners at the bottom of the furnace. More detailed information is given for oil or gas combustion systems later.

2.2.6 Gasification/Liquifaction

Small gasification units operating at atmospheric pressure are often used for biomass near the biomass collection sites. In addition, gas from the natural gasification processes in waste landfills is used by collecting the gas from such sites. In both cases, the gas is combusted in small combustion engines or different applications.

Liquifaction of solid fuels is more complex and has been applied in refineries to produce secondary petrol for transport applications.

In gasification processes, the gaseous, liquid and remaining solid fuel are primary products.

For large power plants, gasification is more interesting under pressurised and high temperature conditions, as direct conversion of heat to electricity is possible in gas turbines and indirectly by steam turbines or combining both (combined cycles). The size and price of such systems are not generally competitive for electricity production with coal or heavy fuel oil. More detailed information is given for fuel specific gasification systems in Chapters 5 and 8.

In principle, all solid fuel combustion furnace types can be used with additional measures related to the gasification processes. The main risk to be avoided is the generation of a mixture of fuel and air within the explosive range. Intermediate products in the form of combustible gases and volatilised liquid secondary fuels can be utilised in gas turbines or combustion engines. For the direct combustion of gasified solid fuels in gas turbines, high efficient dust removal and desulphurisation of gas is required. Expensive separation processes, necessary in refineries, are not needed. This is of interest in commercial terms when prices for gaseous and liquid fuels are high compared to solid fuels. In both cases, the gasification process needs a large amount of the fuel energy reducing the overall efficiency. This loss in efficiency can be reduced by steam generation using the waste heat from the gasifier. Nevertheless, the combustion of gasified fuels generates less electricity than natural gas in gas turbines or combined cycles.

2.3 Direct conversion

2.3.1 General

The direct expansion of hot pressurised (flue) gas in gas turbines and combustion engines allows the generation of mechanical and subsequently electrical energy. Such systems have been developed from mobile systems and often are applied in remote sites like islands or like gas turbines in gas distribution networks. The transfer of combustion heat at high temperature to steam with restricted temperature is associated with exergetic losses. Due to this, interest is growing in higher temperature systems, which give higher electrical efficiency. These technologies can be started very quickly and then can solve peak demands, stabilise frequency or supply voltage. Additionally, these technologies do not necessarily need water for cooling. Nonetheless, they can be coupled to steam processes to increase the overall efficiency, i.e. a combined cycle.

As the electrical efficiency varies with ambient temperature, data for all systems converting heat to electricity are calculated at standard conditions.

2.3.2 Combustion engines

Combustion engines have one or more cylinders in which fuel combustion occurs. Engines convert the chemical energy of fuels into mechanical energy in a design similar to that of an automobile engine. The engine is attached to the shaft of the generator and provides the mechanical energy to drive the generator to produce electricity. Internal combustion generating units for power plants are typically designed to operate on either four- or two-stroke cycles.

Combustion engines are either small or medium, ranging from 2 MW to greater than 50 MW capacity. They are more efficient than gas turbines. In addition, capital costs are low, they are easily transported, and they can generate electricity almost immediately upon start-up. For this reason, internal combustion generators are often used for small loads and to provide emergency power. [21, US EPA, 1997].

Some engines ('low speed two stroke') can reach more than 40 MW_e; 30 MW_e are no longer an exception. These engines were derived from mobile systems generating mechanical energy for transport applications like trucks, trains and ships. In the electricity supply industry this mechanical energy is converted to electrical energy by a generator. This technique is often applied for emergency supply. Compared to gas turbines, combustion is not continuous but takes place in closed combustion chambers. During combustion, the pressure and temperature increase is very high and this allows high a conversion efficiency for small units. Most systems use diesel oil or heavy fuel oil as liquid fuel, but gaseous fuel use is also possible. Combustion engines, operating with heavy fuel oil, are cost efficient solutions for base-load electricity supplies at remote sites like islands.

2.3.3 Gas turbine

Gas turbine systems operate in a manner similar to steam turbine systems except that combustion gases are used to turn the turbine blades instead of steam. In addition to the electric generator, the turbine also drives a rotating compressor to pressurise the air, which is then mixed with either gas or liquid fuel in a combustion chamber. The greater the compression, the higher the temperature and the efficiency that can be achieved in a gas turbine. Exhaust gases are emitted to the atmosphere from the turbine. Unlike a steam turbine system, gas turbine systems do not have boilers or a steam supply, condensers, or a waste heat disposal system. Therefore, capital costs are much lower for a gas turbine system than for a steam system. In electrical power applications, gas turbines are typically used for peak demands, where rapid start-up and short runs are needed [21, US EPA, 1997].

Gas turbines in comparison to furnaces operate at elevated pressure. In gas turbines only clean fuels can be used directly, mainly natural gas often with diesel oil as the back up. Fuels containing ash need flue-gas cleaning systems at the entrance like PFBC or gas cleaning in combination with gasification. More detailed information is provided for gas combustion systems in Chapter 7.

Gas turbines are also used for emergency and peak demand, in large grids. In the case of islands, gas turbines operate with liquid fuel, mainly diesel oil in medium or base load operation.

2.4 Common technical steam processes

2.4.1 General

Most power plants operate using a steam process which uses the fuel energy to generate steam at a high pressure and temperature, both necessary for high efficiency. The heat transfer from the fuel is used to evaporate the boiler water and to overheat steam. In the steam turbine, the steam is expanded across the pressure drop in the turbine. The rate of the pressure drop depends on the cooling medium temperature. The lowest pressure defines the maximum electrical efficiency. Cooling is necessary to condense the steam.

As a compressing liquid, water consumes the least energy, boiler feed water is compressed to return into the water-steam cycle. Cooling techniques are applied to remove the condensation energy from the steam, i.e. for condensing power plants and for co-generation power plants or combined heat and power plants.

2.4.2 Vacuum condensing power plant

So-called condensing power plants use ambient cooling sources to condense the steam at the lowest available temperature and under vacuum conditions.

Seawater cooling for this reason enables the highest efficiency followed by direct cooling with water from a river. Cooling using an intermediate cooling cycle or with dry cooling towers is generally the least effective technique. A temperature gradient between the steam and the environment is necessary to limit transport energy consumption. As electrical efficiency varies with the ambient temperature, data are calculated for standard conditions.

2.4.3 Co-generation/combined heat and power

For cost effective heat production, higher temperatures are necessary compared to the temperature of a vacuum condensing power plant. The first possibility is the extraction of higher pressure steam. This steam is lost for electricity production in the low pressure steam turbine, but the temperature is high enough to supply a district heating system. The next possibility for combined heat and power, is to withdraw steam from the low pressure steam turbine with a smaller loss in electricity generation. Condensation in a back pressure system (above one atmosphere) recovers water from steam condensation at more than 100 °C. Typical district heating systems need temperatures of between 80 and 120 °C. In any case, heat extraction from an optimised water steam circuit reduces electrical efficiency. As the amount of recovered heat increases, the lost electricity can be applied as usable heat. The typical factor for recovered district heat to lost electricity is seven. With lower extraction temperatures, this factor increases. But technical and health criteria limit the lowest temperature for district heating systems. Typical fuel utilisation rates are between 75 and 90 % where high grade electricity and heat are combined as simple energy.

Combined heat and power and/or co-generation are two similar processes in the municipal district heat supply and industry. The industrial application of heat can range between high and low temperatures above ambient temperature. Depending on the temperatures available in a steam process, heat used in industry can be above the steam process or even above the gas turbine outlet temperature. In this case, the industrial heat loss can be recovered by a heat recovery steam generator to generate steam for a lower quality heat supply.

Steam processes using waste gas heat from a gas turbine, a combustion engine or ‘waste’ condensation heat from a steam turbine with a back pressure condensation above atmospheric pressure, can be recovered for low temperature applications. The same conditions as given for district heat applications apply for such utilisation of condensation heat. In general, industrial applications are not limited to winter periods with higher demands for district heating. Thus, industrial applications are more cost efficient under the same plant situation.

If no lower quality heat supply is available for co-generation in industry, only recovery for electricity generation with a vacuum condensing power plant is possible. In this case, fuel energy utilisation is limited similar to direct electricity generation with a heat recovery steam generator (HRSG). For this production of electricity, no additional fuel is necessary as the primary process heat demand needs all fuel. Only with increased steam temperature by supplementary firing, the production of electricity can be optimised to better efficiency. This shows, that fuel utilisation alone is not a good efficiency measure because it does not measure the quality of the CHP process.

The only reliable measure can be exergy, applied in industry as general quality measure for all kinds of energy.

Table 2.1 provides information on CHP in the EU-15 Member States and CHP as a percentage of thermal and total electricity generation in the year 1998.

Member State	CHP electricity (GWh)	Proportion of thermal electricity (%)	Proportion of total electricity (%)
Belgium	3410	9.6	4.1
Denmark	25591	66.9	62.3
Germany	41770	11.3	7.5
Greece	981	2.3	2.1
Spain	21916	22.2	11.2
France	12660	22.7	2.5
Ireland	404	2.0	1.9
Italy	44856	21.6	17.3
Luxembourg	329	87.7	22.5
Netherlands	47835	55.4	52.6
Austria	14268	76.2	24.8
Portugal	3288	12.8	8.4
Finland	25128	75.6	35.8
Sweden	9544	95.5	6.0
United Kingdom	18644	7.4	5.2
Overall EU-15	270624	21.0	10.9

Table 2.1: CHP in EU-15 and CHP as a percentage of thermal and total electricity generation in 1998
[186, Eurostat, 2001], [187, Eurostat, 2002]

2.5 Combined cycle

2.5.1 General

The use of gas turbines by utility companies is now recognised industrially, and the waste gas temperature is about 500 °C or more. This temperature creates the possibility to apply an additional steam cycle process. Such systems optimises the gas and steam processes to optimise the electric efficiency. Combined cycle principles may also be applicable to combustion engines.

Today, combined cycle systems are also used for co-generation or CHP with additional back pressure heat recovery of condensation energy. As the electrical efficiency varies with the ambient temperature, data are calculated for standard conditions.

2.5.2 Supplementary firing of combined cycle gas turbines, and repowering of existing power plants

Combined cycle gas turbines operate at maximum of electrical efficiency at full load. With 10 to 20 % supplementary firing of the heat recovery steam generator (HRSG), the overall efficiency starts to decrease but remains higher than the addition of a separate boiler. For this reason supplementary firing of a HRSG is often used for small scale peak load heat operation in industrial and district heating.

Repowering of existing coal/oil/gas fired power plants operating a steam process with an additional gas turbine is less discussed today. The main advantage of such an arrangement is the small area necessary for a gas turbine and the high flexibility of such systems.

The known applications began with the so-called ‘Kombianlagen’ (combi-plants), where the exhaust gas of the gas turbine was utilised in the steam generator as combustion air with gas or coal as fuel for the steam boiler. Coupled in the form of an existing system with coal for the steam boiler and gas for the gas turbine the gas turbine stays flexible.

Repowering of existing power plants with gas turbines or reciprocating engines will increase the electrical efficiency. The intention is to produce electricity and to also take advantage of the sensible heat of the exhaust gases generated during the combustion of natural gas in the turbine, thus increasing the energy yield of the fuel. The repowering of an existing thermal power plant can also be made by installing reciprocating engines and taking advantage of the sensible heat of the exhaust gases generated by e.g. use of a feed-water combined cycle. In addition, this implies an increase in the electrical output of the facility. The repowering takes full advantage of the existing main equipment and components, as well as of the existing auxiliary equipment and infrastructure. Power plants apply preheated air using exhaust gases to increase efficiency. In combi-plants, waste heat from the gas turbine is used for this purpose and air preheating for compressed air is limited by adiabatic heat of compression.

Repowering can be used to improve the efficiency of an existing boiler(e.g. from 40 to 45 %). It may be useful to improve energy efficiency of existing installations, when over capacity prevents the construction of new installations. The gas turbine and the boiler can be coupled in different ways depending on the actual situation.

2.6 Typical elements of a steam cycle

The process of generating electricity from steam comprises four parts: a heating subsystem (fuel to produce the steam), a steam subsystem (boiler and steam delivery system), a steam turbine (Figure 2.1), and a condenser (for condensation of the used steam).

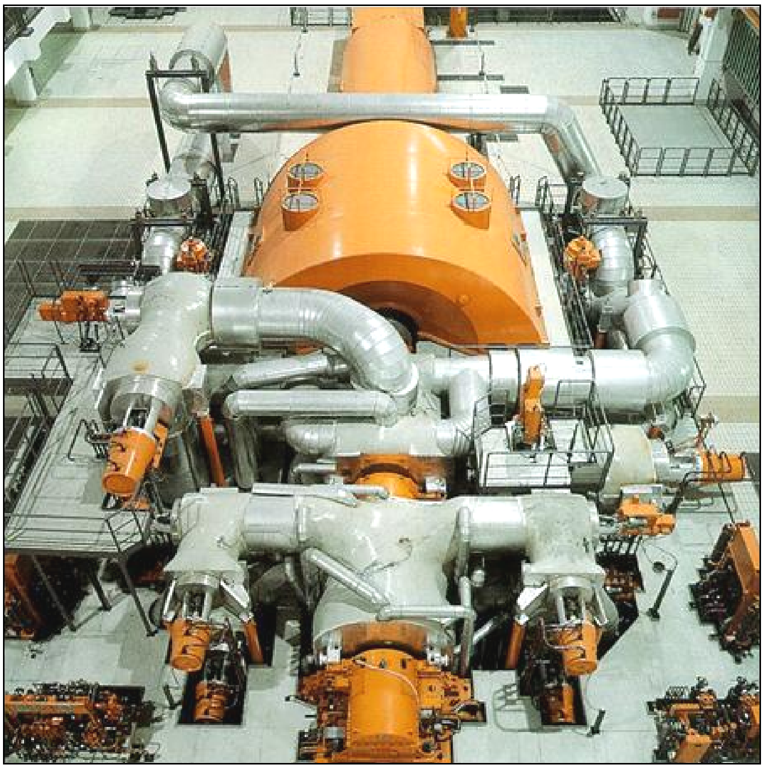


Figure 2.1: Modern steam turbine of a coal-fired power plant
[165, NWS, 2001]

Heat for the system is usually provided by the combustion of coal, natural gas, or oil. The fuel is pumped into the boiler’s furnace. The boilers generate steam in the pressurised vessel in small boilers or in the water-wall tube system (Figure 2.4) in modern utility and industrial boilers. Additional elements within, or associated with the boiler, such as the superheater, reheater, economiser and air heater, improve the boiler efficiency.

Wastes from the combustion process include exhaust gases and, when coal or oil is used as fuel, ash.

High temperature, high pressure steam is generated in the boiler and then enters the steam turbine as shown schematically in Figure 2.2. At the other end of the steam turbine is the condenser, which is kept at low temperature and pressure. Steam rushing from the high pressure boiler to the low pressure condenser drives the turbine blades, which power the electric generator.

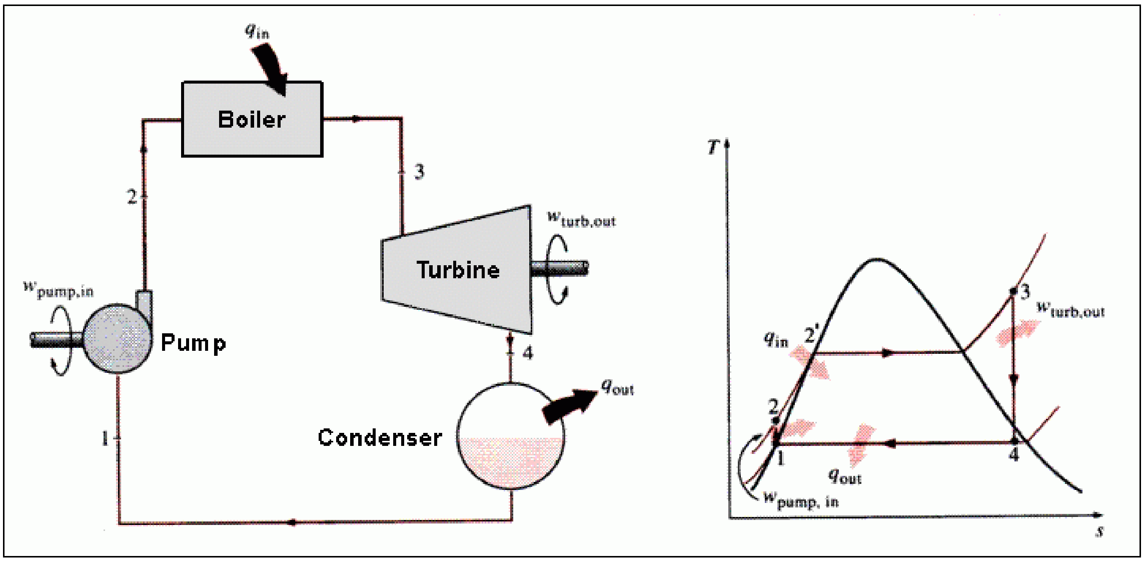


Figure 2.2: Schematic of an ideal combustion cycle
[54, Cortés and Plumed, 2000], [55, Çengel and Boles, 1994], [56, Rogers and Mayhew, 1967]

Steam expands as it works; hence, the turbine is wider at the exit end of the steam. The theoretical thermal efficiency of the unit depends on the high pressure and temperature in the boiler and the low temperature and pressure in the condenser.

A schematic figure showing the Brayton cycle describing the gas turbine process can be found in the Annex 10.1.3 of this document.

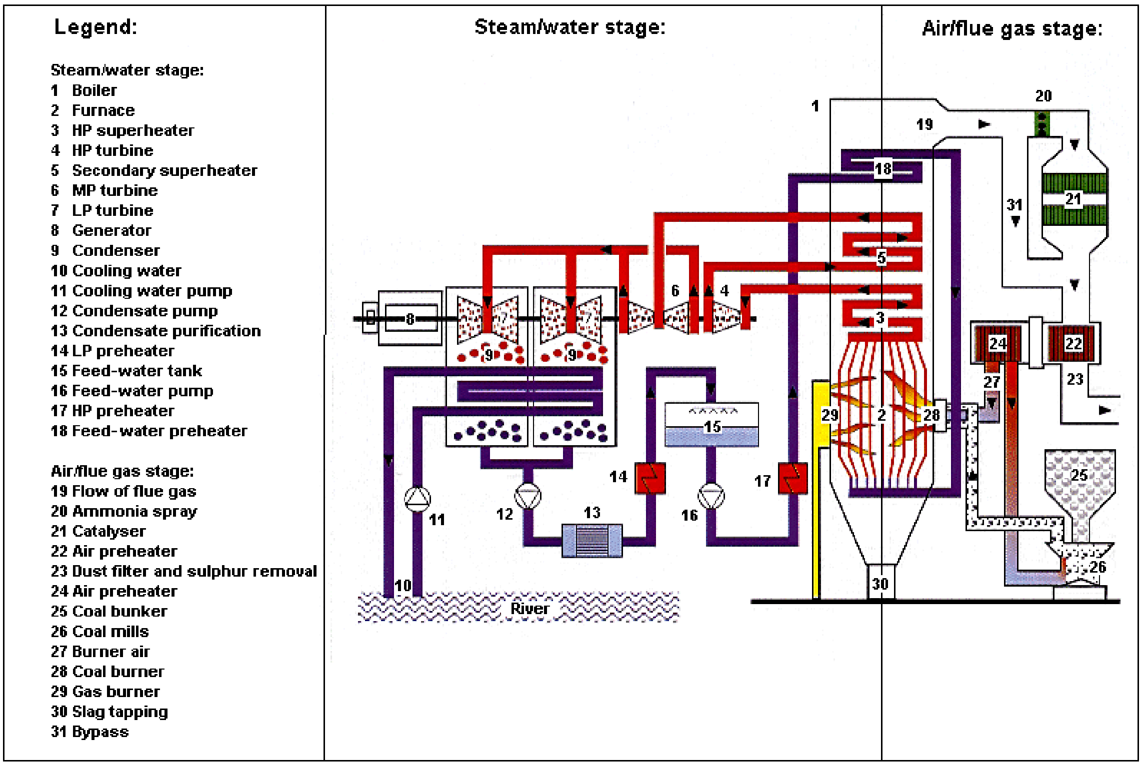


Figure 2.3: Possible concept of a power plant
[113, Verbundkraft, 2002]

Low pressure steam exiting the turbine enters the condenser shell and is condensed on the condenser tubes. The condenser tubes are maintained at a low temperature by the flow of cooling water. The condenser is necessary for efficient operation by providing a low pressure sink for the exhausted steam. As the steam is cooled to condensate, the condensate is transported by the boiler feed-water system back to the boiler, where it is used again. Being a low volume incompressible liquid, the condensate water can be efficiently pumped back into the high pressure boiler.

A constant sufficient flow of low temperature cooling water in the condenser tubes is required to keep the condenser shell (steam side) at proper pressure and to ensure efficient electricity generation. Through the condensing process, the cooling water is warmed. If the cooling system is an open or a once-through system, this warm water is released back to the source water body. In a closed system, the warm water is cooled by recirculation through cooling towers, lakes, or ponds, where the heat is released into the air by evaporation and/or sensible heat transfer. If a recirculating cooling system is used, only a small amount of make-up water is required to offset losses by evaporation and the cooling tower blowdown, which must be discharged periodically to control the build-up of solids. Compared to a once-through system, a recirculated system uses about one twentieth of the water. [21, US EPA, 1997].

2.6.1 The boiler

In general, three types of boilers are commonly used: natural circulation, forced circulation, and once-through boilers, which hold nearly 70 % of today's world market for once-through boilers. Figure 2.4 indicates the major differences between the natural circulation and the once-through boiler concept.

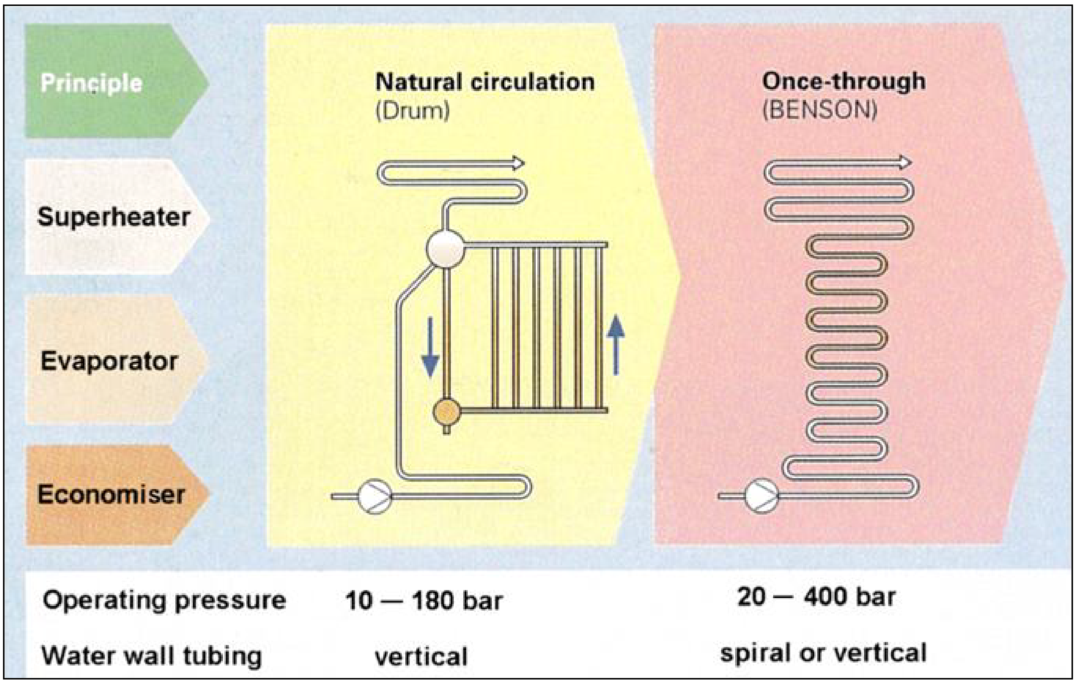


Figure 2.4: Natural circulation and the once-through boiler concept
[80, Siemens, 2000]

In natural circulation boilers, the density difference between the high temperature steam and the low temperature steam/water is used to generate a natural circulation. In forced circulation boilers additionally to the density difference, circulation is supported by circulating pumps. In once-through boilers, the water flow is determined by the feed pump, and the water is evaporated during one single passage. The advantages of the once-through boiler are:

- steam generation is possible with any pressure
- highest achievable efficiency with supercritical steam parameters
- high plant efficiency even with part loads
- short start-up times
- sliding-pressure operation with high load transients
- suitable for all fuels available on the world market.

Boiler components

The boiler or steam generator is a combination of the economiser, evaporator, superheater and the reheater:

- economiser: After the water/steam circuit, feed-water is heated in the economiser to a temperature 10 ºC below the saturation point. The economiser is the first heat-exchanger of the boiler collecting heat from the lower temperature flue-gas at the exit of the boiler
- evaporator: In the combustion chamber, the chemically bound energy of the fuel is released and transferred across the boiler and heat-exchanger walls to the water/steam circuit. The heated water is then evaporated in the boiler evaporator to at least saturated steam for subcritical pressure water/steam conditions, or to superheated steam for supercritical conditions. Usually the evaporator tubes constitute the combustion chamber walls and are aligned in a vertical or a spiral arrangement. A few modern plants work with supercritical water/steam pressure, i.e. a pressure above the critical point in the water-steam diagram. At supercritical pressure the conversion occurs without a phase transition so the evaporation energy is zero and only a peak in heat capacity represents the change in the continuous fluid

- superheater: The superheater uses the highest temperature flue-gas area of the boiler to produce superheated steam. Superheated steam has a temperature significantly above the pressure dependent condensation temperature. Such temperatures are necessary to facilitate the high pressure drop in the steam turbine and thus avoid condensation during the expansion of steam in the high pressure steam turbine. The steam expansion is coupled with a pressure drop and with the adiabatic decrease of the steam temperature. Part of this expanded steam is bled off and used to transfer heat to the feed-water
- reheater: The bulk of the steam is reheated by the flue-gas in the reheater systems to extract further work and to achieve a higher efficiency in the subsequent medium-pressure steam turbine. To optimise efficiency, supercritical plants often use a double reheat stage before steam is introduced into the low pressure steam turbine.

2.6.2 Steam turbine

In the steam turbine, the thermal energy of the steam is converted to mechanical work (i.e. turbine shaft rotation). This occurs between the steam inlet point and the condenser, with the steam expansion being used as the driving force. During this adiabatic steam expansion, the temperature of the steam decreases in association with a pressure drop from about 300 to 0.03 bar for modern LCPs. Due to the large difference in pressure, steam expansion is normally effected in three stages – the high pressure (HP), medium pressure (MP) and low pressure (LP) stages of steam turbines. In most cases, these steps allow the steam to be reheated in reheaters before re-entering the next lowest pressure step in the steam turbine.

2.6.3 Condenser

Finally, in the condenser located downstream of the low pressure section of the turbine, steam is condensed back to water (condensate). After expansion in the steam turbine, some condensation and kinetic energy remains in the steam and is not transferable to mechanical energy. Efficient condensation systems allow a reduction in the pressure of the steam turbine to well below atmospheric pressure (vacuum of down to 0.03 bar, depending on the cooling medium temperature and the cooling water mass flow). This maximises the extraction of mechanical energy from the expansion of steam in the turbine.

2.6.4 Cooling system

Cooling techniques are applied to remove the condensation energy from the steam, i.e. the thermodynamically unusable energy of the process. For some detailed information on cooling techniques, reference is given to the cooling BREF.

2.6.5 Specific costs of different power plant concepts

Specific cost information for different concepts and designs of power plants is given in [166, Müller-Kirchenbauer, 1999], [163, Müller-Kirchenbauer, 2001]. The presented concepts and designs correspond to designs which are important for today's worldwide power generation needs or which have a potential for future use (i.e. designs which are already, or which will soon be, on the market and designs with high efficiencies and whose feasibility is technically proven). For flue-gas cleaning, the cost figures also take into account the costs for the dedusting and desulphurisation (FGD) plant. The cost share for the flue-gas cleaning is higher by including the application of appropriate measures (such as SCR) to reduce NO_X emission, which are standard techniques in a large number of combustion plants operated today. Figure 2.5 shows the total investment costs (in USD) and the itemised cost breakdown for nine power plant concepts.

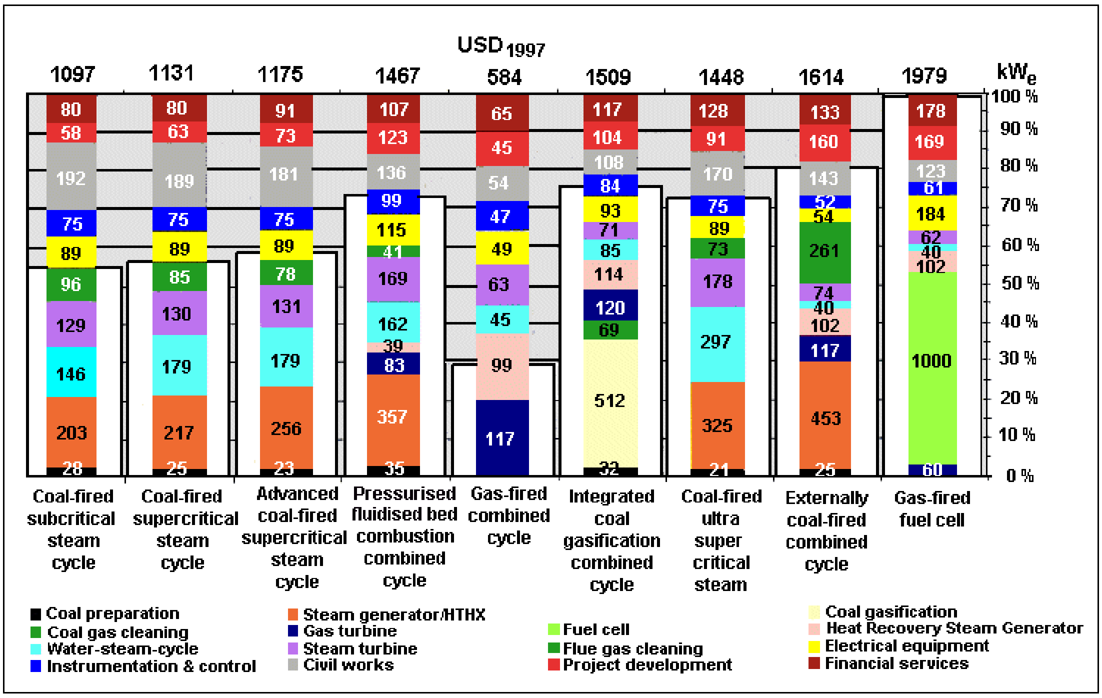


Figure 2.5: Specific investments and their structure for selected power plant concepts [163, Müller-Kirchenbauer, 2001]

There are considerable differences in the maturity of these concepts. For example, subcritical steam-cycle power plants have been in operation throughout the world for decades and have been refined and continually developed whereas other techniques are still under research and development. Step by step development of sub-critical steam cycle technology has led to supercritical steam generators which combine the advantage of high availability with higher efficiency. Steam generators for steam at 580 ºC and 260 bar have been in commercial operation for several years, and the next step, i.e. raising these parameters to 600 ºC and 300 bar, is currently taking place.

There is also an increasing amount of operational experience being gained on gas-fired combined-cycle power plants under commercial application. Pressurised fluidised bed combustion and integrated gasification combined cycles are in operation in several demonstration and pilot plants. However, concepts with ultra-supercritical steam (700 ºC and 375 bar), external coal-firing, or with fuel cells still need further research and development. [166, Müller-Kirchenbauer, 1999], [163, Müller-Kirchenbauer, 2001].

2.7 Efficiency

There are different ways of describing the efficiency of a combustion installation so it is necessary to say how the efficiency is or can be defined, and under which conditions it is measured. There are also a number of national guidelines such as [48, VDI, 1998], [52, BSI, 1974], [51, DIN, 1996] describing acceptance tests and the measurements of certain efficiencies.

The efficiencies defined below [48, VDI, 1998] are to be understood as efficiencies at a certain electrical output and normal operating mode, i.e. as the power station is operated in daily generation mode (e.g. number of mills, number of burners, with or without calorifier). They are calculated from averaged measured values attained from the values recorded over a certain period of time.

2.7.1 Carnot efficiency

The ideal efficiency of a thermal process or ‘Carnot’ efficiency is a measure of the quality of the conversion of heat into work between two temperature levels. The Carnot efficiency can be written as:

$$\eta_C = 1\text{-}T_0/T$$

Here, T_0 is the ambient temperature and T the temperature at which the heat is yielded or taken up, both expressed in Kelvin (T(K) = T(ºC) + 273.15). Figure 2.6 compares the ideal (Carnot) efficiency with the efficiencies actually achieved by the combustion (thermal) techniques currently in use.

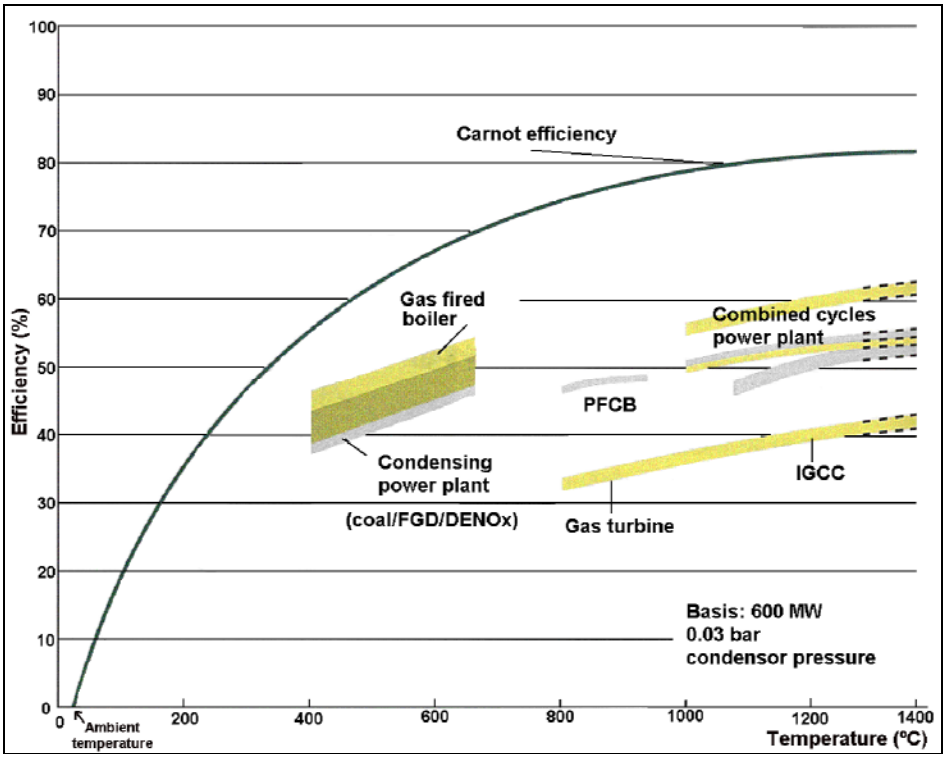


Figure 2.6: Ideal (Carnot) efficiency compared to the efficiencies actually achieved by the thermal energy generation techniques currently in use

2.7.2 Thermal efficiency

The definition of thermal efficiency considers only the actual cycle process used in the power station. The efficiency is then the ratio of the useful mechanical output to the heat flow transferred to the cycle process media (as a rule, air or water).

In this context, the useful mechanical output is the mechanical output from the turbine, when the feed pump is driven by a turbine which is operated with extraction steam from the main turbine. As the condensate pump also contributes to raising the pressure, it is considered to be part of the feed pump, from a thermodynamic point of view. Its mechanical output must therefore be subtracted from the mechanical output of the turbine. The mechanical output of the turbine, in a thermodynamic sense, is in this case the output resulting from the steam mass flow and the enthalpy difference. If the feed pump is driven by an electric motor, then the useful mechanical output is equal to the difference between the mechanical output of the turbine minus the drive outputs of the feed pump plus the condensate pump. This also applies when the feed pump is driven directly by the turbine shaft. The heat flow transferred to the process is that heat flow transferred to the water/steam cycle.

In the case of a combined gas/steam turbine process, the useful mechanical output is the mechanical output of the steam turbine plus the mechanical output of the gas turbine, when the feed pump is driven by a turbine which operates with extracted steam. However, the output of a condensate pump has to be subtracted from this. If the feed pump is driven by an electric motor, then the useful mechanical output is equal to the difference between the mechanical output of the turbine and the drive output of the feed pump plus the condensate pump. The heat flow transferred to the circuit process in a gas/steam turbine process is equal to the heat flow transferred to air in the combustion chamber of the gas turbine, plus the heat flow transferred to the water/steam cycle in the steam generator by combustion. In a pure waste heat boiler unit, the heat flow transferred to the water steam cycle is zero [48, VDI, 1998].

2.7.3 Unit efficiency

The definition of unit efficiency considers the whole power station unit as presented in Figure 2.7. Unit efficiency is then the ratio of the net electrical output to the energy supplied with the fuel. The electrical output according to this definition is the output on the high voltage side of the main transformer.

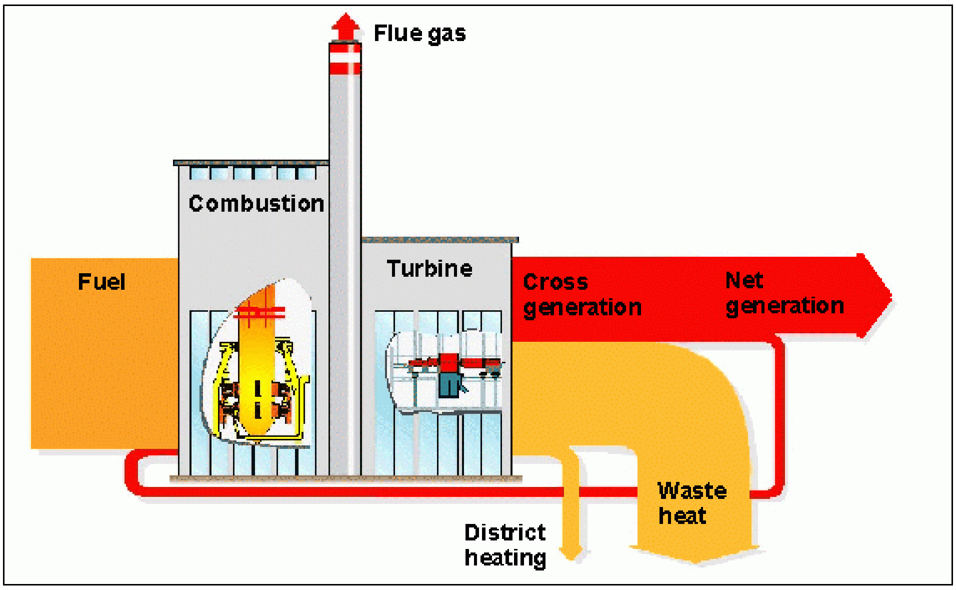


Figure 2.7: Energy transfer in a thermal power plant
[64, UBA, 2000]

2.7.4 Unit efficiency for steam withdrawal

If, in a power station unit, steam is extracted for heating or process purposes, then this steam is no longer available for power generation. In order to be able to compare the unit efficiency in this case with the efficiency of pure power generation, the electrical output which could be obtained from the extracted heating steam if it were to expand to the condenser pressure, has to be added to the electrical output.

For the extraction of heating steam, a correction for the power loss is used. Such correction can be shown in the diagrams presented in [48, VDI, 1998]. In these diagrams, the power loss characteristic depends on the flow temperature, with the return temperature as a parameter for single-stage, double-stage and triple-stage heating. The diagrams apply to condenser pressures of 30, 40, 70 and 80 mbar.

In the case of process steam extraction, the condensate can only be returned to the circuit to a limited extent, if at all. This would entail diagrams with too many parameters. But the influence of the returned condensate can be separated from the influence of the extracted steam. The correction for process steam extraction is also shown in diagrams presented in [48, VDI, 1998].

2.7.5 Exergy concept and exergy efficiency

Since electricity can be converted into heat (whereas the reverse process is, of course, not completely possible) electricity has a higher value than heat. Since heat contains a greater share of convertible energy at higher temperatures than it does at lower temperatures, the quality of heat at higher temperatures is higher than at lower temperatures. These issues are considered by the concept of exergy that express the convertibility of energy in qualitative terms. This can be achieved by using quality factors (QF), which give the fraction of exergy in a total quantity of energy. The quality factor of electricity and mechanical energy is 1 (electricity is pure exergy). The quality factor of heat, however, depends on the temperature at which the heat is available. The expression for one unit of heat at temperature T into work has long been known. It is called the ‘Carnot factor’, and has previously been discussed in Section 2.7.1. The Carnot factor is, quite simply, the quality factor for heat. This factor is always less than 1, becoming 0 at ambient temperature [49, Electrabel, 1996].

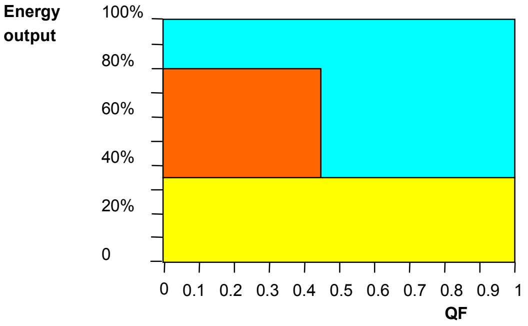
By applying such simple quality factors to the energy input ($En_{\text{energy input}}$) and the useful energy output ($En_{\text{useful energy output}}$) of a process, the exergetic efficiency of a combustion process can be calculated and compared to the fuel efficiency. The exergetic efficiency (η_{ex}) can then be expressed as follows (see Figure 2.8):

$$\eta_{ex} = \sum(QF \cdot En_{\text{useful energy output}})/\sum(QF \cdot En_{\text{energy input}})$$

By using this methodology, a comparison of the energetic and exergetic efficiencies can be made as shown in the example below.

T_0 = Ambient temperature in Kelvin (0 °C =273 K)
T_W = Temperature of the supplied heat (in K)
QF = Quality factor (exergy/energy ratio)
η_C = Carnot or quality factor for heat ($=1-T_0/T_W$)

E = Electrical energy output (%)
H = Usable heat energy output (%)
L = Thermal losses (%)
I = Fuel energy supplied (= 100 %)



EXAMPLE : Industrial combined heat and power generation.
Gas turbine (new technology) and recovery steam boiler.

Assumptions: Tw= 473 K (200 °C)

I → 🟨 **E = 38%** **QF(E) = 1**
→ 🟧 **H = 40%** **QF(H) = 0.42**
→ 🟦 **L = 22%**

EO = total energy output = E + H
EO = 0.78
η_{ex} = energy yield = E x QF(E) + H x QF(H)
η_{ex} = 0.55 (= 0.38 x 1 + 0.4 x 0.42)

Figure 2.8: Example demonstrating the methodology for calculating the exergetic efficiency [49, Electrabel, 1996]

The results from different types of combustion techniques are presented in Table 2.2.

Combustion Technique	**Fuel energy supplied (= 100 %)**	**Electrical energy output (%)**	**Usable heat energy output (%)**	**External losses (%)**	**T_W Temperature of supplied heat (K)**	**Quality factor of heat (QF = 1-T_0/T)**	**Quality factor of electricity**	**Total energy output EO (fuel efficiency)**	**Exergetic efficiency η_{ex}**
Heat generation Type: heating boiler for space heating, where T_W = 70 ºC (343 K)	100	0	90	10	343	0.2	-	**0.90**	**0.18**
Electricity generation Type: combined cycle (recent high yield combined cycle technology)	100	55	0	45	-	-	1	**0.55**	**0.55**
Industrial CHP plant Type: steam boiler + back pressure steam turbine, (where T_W = 200 ºC (473 K) steam for industrial process)	100	20	60	20	473	0.42	1	**0.80**	**0.45**
Industrial CHP plant Type: combined cycle with steam tapping, where T_W = 200 ºC (473 K) (steam for industrial process)	100	50	12	38	473	0.42	1	**0.62**	**0.55**
Industrial CHP plant Type: gas turbine (new technology) with recovery steam boiler, where T_W = 200 ºC (473 K)	100	38	40	22	473	0.42	1	**0.78**	**0.55**
Industrial CHP plant Type: gas turbine with recovery steam boiler, where T_W = 200 ºC (473 K)	100	32	48	20	473	0.42	1	**0.80**	**0.52**
Industrial CHP plant Type: gas turbine with recovery steam boiler with back pressure steam turbine where T_W = 200 ºC (473 K)	100	35	45	20	473	0.42	1	**0.80**	**0.54**
Small scale CHP plant Type: gas engine with heat-exchanger where T_W = 70 ºC (343 K) (for space heating and small-scale industrial applications)	100	35	55	10	343	0.20	1	**0.90**	**0.46**

Table 2.2: Examples of energetic and exergetic efficiencies of different types of combustion plants [49, Electrabel, 1996]

2.7.6 Influence of climate conditions on efficiency

The climate expressed in terms of wet and dry bulb temperatures is an extremely important site-specific condition. It influences both the choices of the type of cooling and the possible end temperature of the process. The contradiction of cooling with air and/or water is that when the cooling demand is high it becomes more difficult to achieve the requirements. Particularly in areas where high air temperatures and high water temperatures coincide with lower water availability during part of the year, a certain operational flexibility of the cooling system can be very important and may be achieved by combining water and air cooling. Sometimes, however, a certain loss of efficiency has to be accepted.

To reach the required end temperature, the cooling medium must have a lower temperature than the medium to be cooled, but this depends on the dry- and wet-bulb temperatures. A wet-bulb temperature is always lower than a dry-bulb temperature. The wet-bulb temperature depends on the measured temperature of the atmosphere, the humidity and the air pressure. For latent (evaporative) heat transfer, the wet-bulb temperature is the relevant temperature. It is theoretically the lowest temperature to which water can be cooled by evaporation. For sensible heat transfer, the dry-bulb (dry air) temperature is relevant, where air is the coolant.

For the selection of the type and design of the cooling system, the design temperature is important and usually relates to summer levels of the wet bulb and dry bulb temperatures. The greater the difference between these temperatures and the higher the dry bulb temperatures, the more difficult it will be to reach low end temperatures with dry air-cooled systems. As mentioned earlier, this can lead to efficiency losses. Measures can be taken to overcome the loss, but they require a certain investment.

As an example, Table 2.3 shows how, for different climate conditions in Europe, the choice of a dry or a wet cooling system can affect process efficiency losses due to the Carnot cycle. In the example, the approach for wet cooling is considered to be 4 K and this has to be added to the wet bulb temperature to get the minimum end temperature of the coolant. The approach for dry cooling is set at 12 K to be added to the dry bulb temperature. The larger the difference between the wet and the dry end temperatures, the higher the loss of efficiency (in this example), where losses of 0.35 % per K on average occur. At the same time, for example, with a 5 % efficiency loss, the efficiency of a conventional power plant would be 38.6 % instead of 40 %.

Country and station [1]		Parameter						
		Dry-bulb temp. (1 %)[2] (°C)	Wet-bulb temp (1 %)[2] (°C)	Temperature difference (K)	End temp. dry system3 (°C)	End temp. wet system[4] (°C)	ΔT wet-dry (K)	Efficiency loss[5] (%)
Greece	Athens	36	22	14	48	26	22	7.7
Spain	Madrid	34	22	12	46	26	20	7.0
France	Paris	32	21	11	44	25	19	6.7
Italy	Rome	34	23	11	46	27	19	6.7
Austria	Vienna	31	22	9	43	26	17	6.0
Germany	Berlin	29	20	9	41	24	17	6.0
Netherlands	Amsterdam	26	18	8	38	22	16	5.6
France	Nice	31	23	8	43	27	16	5.6
UK	London	28	20	8	40	24	16	5.6
Germany	Hamburg	27	20	7	39	24	15	5.3
Norway	Oslo	26	19	7	38	23	15	5.3
Belgium	Brussels	28	21	7	40	25	15	5.3
Spain	Barcelona	31	24	7	43	28	15	5.3
Finland	Helsinki	25	19	6	37	23	14	4.9
Denmark	Copenhagen	26	20	6	38	24	14	4.9
Portugal	Lisbon	32	27	5	44	31	13	4.6
UK	Glasgow	23	18	5	35	22	13	4.6
Ireland	Dublin	23	18	5	35	22	13	4.6

Notes:
1) the given data in the table are illustrative of the variation of the climate in Europe. Other references may provide slightly different data. The exact data or a site can be analysed by a meteorological institute.
2) statistically only 1 % of the maximum temperatures are above this data
3) approach 12 K
4) approach for wet system: 4K
5) loss of efficiency 0.35 % per ΔT K on average

Table 2.3: Examples of effect of climatic conditions in Europe on the lost of efficiency of power plants [45, Eurovent, 1998]

2.7.7 Relationship between efficiency and environmental issues

According to [64, UBA, 2000] increases in efficiency have the following effects on fuel consumption, waste heat and emissions:

Savings in fuel	$\Delta e = 1 - \frac{\eta_1}{\eta_2}$
Reductions in waste heat	$\Delta a = \frac{\Delta e}{1 - \eta_1}$
Reductions of CO_2 emissions	$\Delta C = 1 - \frac{\eta_1}{\eta_2}$
Reductions in pollutant gas emissions	$\Delta \varepsilon = \frac{3.6 \bullet V_R \bullet x}{H_u} \bullet (\frac{1}{\eta_1} - \frac{1}{\eta_2})$ (mg/kWh)

Variables:

η_1	*efficiency before improvement*	
η_2	*efficiency after improvement*	
V_R	*volume of air/kg fuel*	*(m^3/kg)*
x	*threshold limit value*	*(mg/m^3)*
H_u	*lower calorific value*	*(MJ/kg)*

2.7.8 Losses of efficiency in combustion plants

The heat energy resulting from the combustion of fossil fuels is transferred to the working medium (steam). During this process, part of the energy is lost in the flue-gas. The total losses from the generation of steam depend on the fuel (ash and water content, calorific value); the capacity and operation of the steam generator; the air-fuel mix; the final temperature of the flue-gas; and the mode of operation. The operation of the steam generator requires continuous surveillance. The heat losses from the steam generator can be categorised as:

- losses via the off-gas. These depend on the flue-gas temperature, air mix, fuel composition and the level of fouling of the boiler
- losses through unburned fuel, the chemical energy of which is not converted. Incomplete combustion causes CO and hydrocarbons to occur in the flue-gas
- losses through unburned material in the residues, such as carbon in bottom and fly ash
- losses via the bottom and fly ash from a DBB and the slag and fly ash from a WBB
- losses through conduction and radiation. These mainly depend on the quality of insulation of the steam generator.

In addition to the heat losses, the energy consumption needed for the **operation of auxiliary** machinery (fuel transport equipment, coal mills, pumps and fans, ash removal systems, cleaning of the heating surfaces, etc.) also has to be taken into consideration.

Poor combustion lowers the economic viability, increases the environmental impacts and is detrimental to the safety of the plant. The following parameters affect the viability of the plant and may, therefore, be monitored to keep the plant's efficiency as high as possible:

- fuel composition
- fineness of grind
- flue-gas composition (O_2, CO_2, CO)
- air mix and flue-gas volume flow
- air leaking into the combustor
- boiler fouling
- temperatures of the combustion air and flue-gases
- temperature behaviour within the heating surfaces
- reduction of draught
- flame profile
- combustible proportion of residue (annealing loss).

2.7.9 Generic technical measures to improve LCP efficiency

Co-generation (CHP)
The generation of heat (process steam or district heating) and electrical energy increases the fuel efficiency (fuel utilisation) to about 70 – 90 %.

Combustion
The fuel is mixed with air and burned in the boiler. It is not possible to obtain an ideal mix between the fuel and air, and therefore, more air than is necessary for stoichiometric combustion is supplied to the boiler. Furthermore, a small percentage of the fuel does not fully combust. The flue-gas temperature must be kept high enough to prevent condensation of acid substances on the heating surfaces.

Unburned carbon-in-ash
Optimisation of the combustion leads to less unburned carbon-in-ash. It should be noted that NO_X abatement technologies using combustion modification (primary measures) show a tendency of increased unburned carbon. Increased unburned carbon could also worsen and harm the quality of the coal fly ash and make it difficult, or even prevent, their utilisation for certain applications, with the risk that they may not comply with the specifications and requirements laid down in relevant national and European standards.

Air excess
The amount of excess air used depends on the type of boiler and on the nature of the fuel. Typically, 12 – 20 % excess air is used for a pulverised coal-fired boiler with a dry bottom. For reasons of combustion quality (related to CO and unburned carbon formation), and for corrosion and safety reasons (e.g. risk of explosion in the boiler) it is often not possible to reduce the excess air levels further.

Steam
The most important factors in increasing efficiency are the highest possible temperature and pressure of the working medium. In modern plants the partially expended steam is reheated by one or more reheating stages.

Flue-gas temperature
The flue-gas temperature leaving the clean boiler (depends on the fuel type) is traditionally between 120 and 170 °C, due to risks of acid corrosion by the condensation of sulphuric acid. However, some designs sometimes incorporate a second stage of air heaters to lower this temperature below 100 °C, but with special claddings on the air heater and the stack, which makes this reduction economically unprofitable. By power plants designed without stacks, the flue-gas temperature is between 65 and 70 °C.

Vacuum in the condenser

After leaving the low pressure section of the steam turbine, the steam is condensed in condensers and the heat released into the cooling water. In order to ensure the maximum pressure drop over the steam turbines, it is desirable to reduce the vacuum to a minimum. In general, the vacuum is dictated by the temperature of the cooling water which is lower with once-through cooling systems than with a cooling tower. The best electrical efficiency is possible by seawater or fresh water cooling and a condenser-pressure with approximately 3.0 kPa. The preferred option is to use seawater or river water if this available.

Variable pressure and fixed pressure operation

In fixed pressure operations, the pressure before the turbines at all load levels is kept more or less constant by changes in the flow cross-section at the turbine inlet. In variable pressure operations with the turbine inlet cross-section at its maximum, the power output is regulated by changes in the pressure before the turbines.

Condensate and feed-water preheating

The condensate coming out of the condenser and the boiler feed-water are heated by steam to just under the saturation temperature of the extracted steam. The thermal energy from the condensing process thus feeds back into the system, reducing the amount of heat otherwise released from the condenser, therefore improving the efficiency.

The optimisation measures taken to improve the efficiency of power plants between 1993 and 2000 which resulted in a CO_2 reduction of 11.0 million tonnes per year, are shown in Figure 2.9.

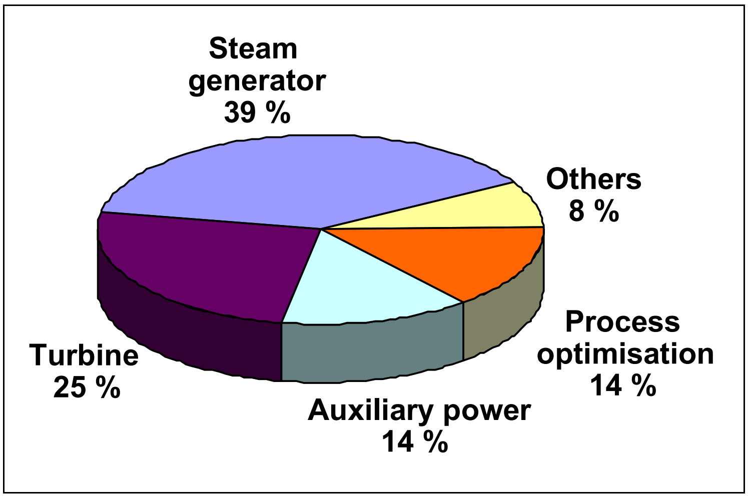


Figure 2.9: Improvements in the efficiency of power plants between 1993 and 2000 [134, Hourfar, 2001]

3 COMMON PROCESSES AND TECHNIQUES TO REDUCE EMISSIONS FROM LARGE COMBUSTION PLANTS

There are several processes, variations in equipment and techniques that can be used to reduce emissions from combustion installations for energy generation. A large number of the techniques are common to most fossil fuel-fired combustion plants and, therefore, to avoid repetition in the fuel-specific chapters, these are described together in this chapter.

This chapter gives detailed descriptions and information on the following common techniques, processes and issues:

- primary measures
- techniques to reduce the emissions of particulate matter
- techniques to reduce sulphur oxide emissions
- techniques to reduce nitrogen oxide emissions
- combined techniques to reduce sulphur oxide and nitrogen oxide emissions
- techniques to reduce heavy metal emissions
- techniques to reduce other pollutants arising from the combustion of fossil fuels
- techniques to control releases to water
- techniques to control releases to land
- cooling techniques
- emission monitoring and reporting
- management systems.

The determination of Best Available Techniques (BAT) for the combustion of specific fuels (coal and lignite, biomass and peat, liquid fuels, gaseous fuels and the co-combustion of waste and recovered fuel) identified by the Technical Working Group are covered in Chapters 4 to 8 respectively.

The different parts of techniques to consider in the determination of BAT in these chapters include more detailed fuel related information on, e.g. the way techniques have been improved and differ from the generic description. They also provide data on achievable emission levels in fuel-specific areas. This approach has been used to minimise repetitive descriptions and to allow the transfer of information and techniques across chapters.

Except for the Environmental Management System (EMS), BAT are not specified for the common processes described in this chapter, but the various common processes and techniques are for consideration in the determination of BAT and, therefore, contribute to those BAT described in Chapters 4 to 8. Additionally, as the techniques described in this chapter are also suitable for reducing overall emissions, they can also influence the way existing plants can be improved.

Chapter 3 should be used in conjunction with Chapters 4 to 8 to give a complete picture of a fossil fuel-fired combustion installation and to highlight the ways in which the impact on the environment as a whole can be reduced.

A number of reports, books and other documents are available to the public on the reduction of emissions (especially to air and water) and on waste generation and on the options for re-using residues. With respect to techniques currently used to reduce air emissions from large combustion plants, the European Commission (DG Transport and Energy) has published a detailed technical document about flue-gas cleaning [33, Ciemat, 2000]. This has been produced within the framework of the ‘Thermie-Programme’, and has provided background material for the consideration of techniques to reduce air emissions. For more detailed technical information, the original document should be consulted.

The reduction of emissions from large combustion plants can be carried out in different ways, but in general measures can be split into two categories, i.e. primary or secondary measures, where:

Primary measures: Integrated measures to reduce emissions at source or during combustion, including:

- fuel-supply measures
- combustion modifications.

Secondary measures: End-of-pipe measures, i.e. those that control emission to air, water and soil.

3.1 Some primary measures to reduce emissions

3.1.1 Fuel switch

The possibility of switching fuel from solid to liquid or gas and liquid to gas is not considered in this document as the technical, economic and political feasibility of a fuel switch is largely determined by local circumstances. However, in general, the use of fuels with a lower content of sulphur, nitrogen, carbon, mercury, etc. is an option to consider.

Coal washing facilities are still a technique to reduce both ash emissions and emissions of sulphur dioxide. More importantly, it can be a cost effective way for an operator to improve emissions. However, fuel preparation techniques are mainly applied at the supply source and will, therefore, not be discussed further as they are outside the scope of this BREF.

3.1.2 Combustion modifications

Additives introduced into the combustion system support complete combustion but can also be used as primary measures to reduce emissions of dust, SO_2, NO_X and fuel specific trace elements.

Combustion related measures are possible by combustion modifications, including:

- capacity derating
- burner modifications
- in-furnace combustion modifications
- air and fuel modifications (e.g. flue-gas recycling, fuel air premixing, the use of additives, fuel mixing, drying, finer grinding, gasification, pyrolysis).

Possible measures to apply for combustion modifications are given in Table 3.1. Details for these primary measures are very specific to the fuel and combustion system applied and are given in Chapters 4 – 8. Reciprocating engine primary measures are described in Chapters 6 and 7.

Combustion modifications	Capacity derating	Air and fuel modifications	Burner modifications	In-furnace combustion modifications
Solid fuels, PM control	Lower volume flow and higher oxygen surplus reduces temperature and slagging	Pre-drying, gasification, pyrolysis of fuel, fuel additives, i.e. low melting additives for slag tap furnace with liquid ash removal (tested for pressurised coal combustion for gas turbines)	Liquid ash removal, cyclone burner in slag tap furnace	Liquid ash removal, slag tap furnace; circulating fluidised bed combustion, coarse ash control
Solid fuels, SO_2 control	Reduced temperature reduces sulphur volatilisation	Use of low sulphur fuel and sorbent fuel additives, i.e. lime and limestone for fluidised bed combustion	Burner with separate additive injection	Over fire air injection of absorbents, i.e. limestone
Solid fuels, NO_X control (reduction of NO_X production)	Reduced temperature	Mixing and finer grinding of fuel, flue-gas recycling reduces NO_X production	Low NO_X burners	Staged combustion and reburning
Liquid fuel, PM control	Reduced temperature reduces slagging	Gasification, pyrolysis of fuel, additives for low soot combustion	-	Optimised combustion
Liquid fuel, SO_2 control	-	Use of low sulphur fuel and additives for absorption	-	-
Liquid fuel, NO_X control (reduction of NO_X production)	Reduced temperature	Flue-gas recycling	Low NO_X burners	Staged combustion*, reburning water and steam injection**
Gaseous fuel, PM control				Optimised combustion
Gaseous fuel, SO_2 control				
Gaseous fuel, NO_X control (reduction of NO_X production)	Reduced temperature	Flue-gas recycling fuel air premixing**	Low NO_X burners	Staged combustion*,*** reburning, water and steam injection **
Notes: * not applicable to existing gas turbines ** only practised for gas turbines *** Staged combustion is differently applied in gas turbines and furnaces				

Table 3.1: Primary measures for emission control
[58, Eurelectric, 2001]

The use of additives to the fuel can be a fuel supply measure for small combustion systems or a primary combustion measure at the LCP site. LCP integrated fuel modification measures necessary for optimised combustion, such as fuel mixing, fuel additives, crushing, and grinding of solid fuels, are dealt with in Chapters 4, 5, 6, and 8 when applicable. Some LCP integrated fuel side measures currently under development are special integrated fuel preparation techniques. In addition, this includes measures to enhance efficiency, such as the pre-drying of solid fuels, and gasification or pyrolysis of solid or liquid fuels with the necessary fuel gas cleaning for combined cycle applications.

When gasification or pyrolysis is applied, intermediate products such as coal gas and petroleum coke are also secondary fuels, and therefore, these are discussed with gaseous and solid fuels in Chapters 4 and 6.

3.2 Techniques to reduce particulate emissions

During the combustion of fossil fuels, the mineral matter (inorganic impurities) converts to ash and partly leaves the boiler as fly ash along with the flue-gas. The particles suspended in the flue-gas as fly ash constitute the primary particle matter entering the particulate control device. The characteristics and the amount of the fly ash depend on the fuel used, for example, on the mineral composition of the coal and the combustion type. The performance of the particulate control device is affected by changes in the resistivity and cohesiveness of the fly ash, which depends on the mineralogy of coal as fuel and the amount of unburned carbon content in the fly ash. The combustion type affects the particle size distribution in the fly ash and hence also affects particulate emissions. Fine particulate matter may also contain higher concentrations of heavy metal elements than coarser particles. This is because fine particles have a greater total surface area available for trace elements (heavy metals), such as mercury, to condense on.

Different technologies such as electrostatic precipitators (ESP), fabric filters and wet scrubbers are commonly used to remove particulate matter from the flue-gas. Because mechanical dust arrestors such as cyclones and SO_3 injections cannot be used alone, these techniques are not considered or described in this document. Figure 3.1 presents an overview of the currently used particulate matter control devices.

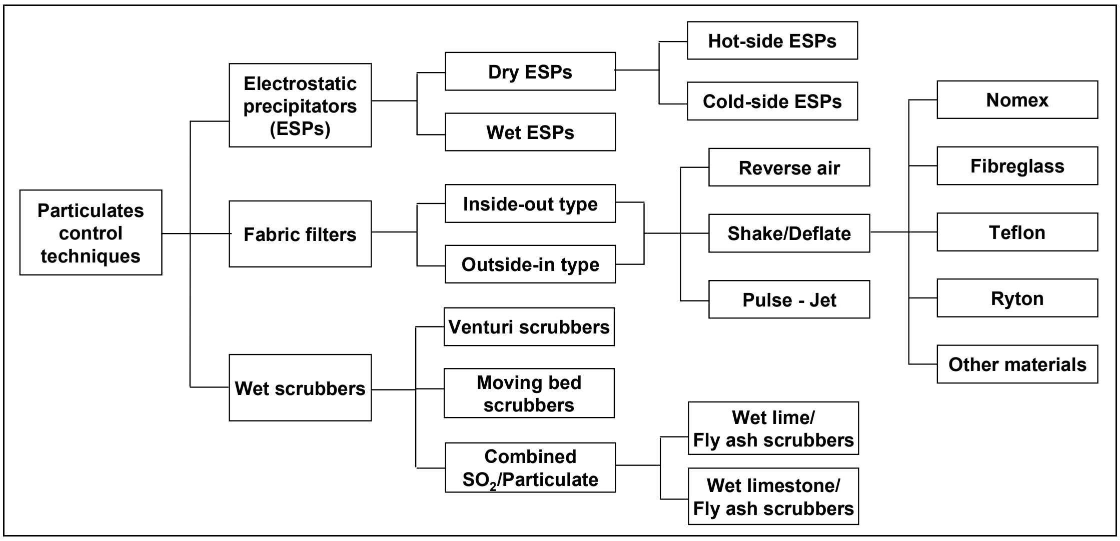


Figure 3.1: Overview of the currently used particulate matter control devices

ESPs with fixed/rigid electrodes are the most important technology currently used. Cold-side ESPs are located after the air preheater and operate over the temperature range of 80 – 220 °C. Hot-side ESPs are located before the air preheater where the operating temperature range is 300 – 450 °C. However, fabric filters, which generally operate over the temperature range 120 - 220 °C, have also become increasingly important over the last decade. Regarding the lifetime of filter bags, for a FF applied after a coal fired power plant: between 5000 – 18000 hours have been estimated. for the ESP: after 50000 hours, small cracks in the emitting electrodes may occur. The choice between applying an ESP or fabric filtration generally depends on the fuel type, plant size, boiler type and the configuration. Both technologies are highly efficient devices for particulate removal, which can be further improved by flue-gas conditioning. For ash removal, the fabric filter technique is only applied for some plants in South Africa, US, Australia and Poland. ESP plus FF are also applied to reduce PM_{10}, $PM_{2.5}$ and mercury. For specific coals, the use of SO_3 injection and ESP in combination is used to reduce particulate emissions. Wet scrubbers, e.g. for dust control, are used far less than ESPs and fabric filters, and then mostly just in the US. They can have high power consumptions and generally achieve lower particulate removal efficiencies, especially of fine particles, compared to ESPs and fabric filters. This is not the case for wet scrubbers used for desulphurisation which have an additional reduction impact on dust emissions.

3.2.1 Electrostatic precipitators (ESPs)

The electrostatic precipitator (ESP) is used extensively in large combustion plants and is capable of operating over a wide range of temperature, pressure and dust burden conditions. It is not particularly sensitive to particle size, and collects dust in both wet and dry conditions. Corrosion and abrasion resistance are built into the design [27, Theodore and Buonicore, 1992], [28, Soud, 1993], [29, Soud, 1995], [30, VDI, 1998], [33, Ciemat, 2000]. A typical arrangement of an ESP is shown in Figure 3.2.

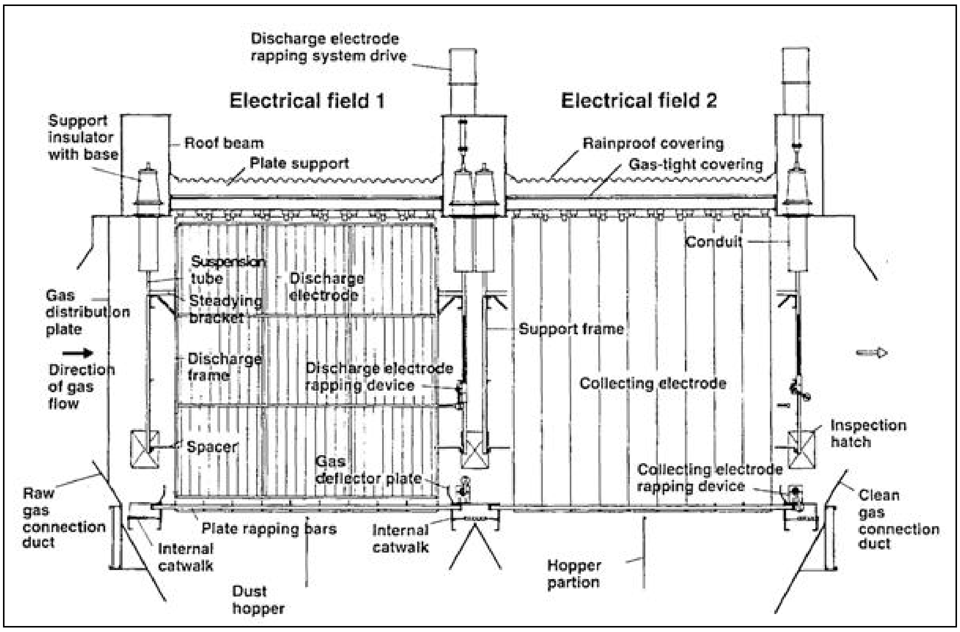


Figure 3.2: Typical schematic arrangement of an ESP
Note: only two fields shown but in LCPs, ESPs are commonly applied with three to five fields depending on the fuel characteristics
[36, Lurgi, 1999]

An electrostatic precipitator (ESP) consists of a hopper-bottomed box containing rows of plates forming passages through which the flue-gas flows. Centrally located in each passage are emitting electrodes energised with high voltage direct current, which is provided by a transformer/rectifier (T/R) set. The electrical field is applied across the electrodes by a small direct current at high voltage (100 kV). The voltage applied is high enough to ionise the gas molecules close to the electrodes, resulting in a visible corona. The flow of gas ions from the emitting electrodes across the gas passages to the grounded collecting plates constitutes what is called corona current.

When passing through the flue-gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The electric field forces the charged particles out of the gas stream toward the grounded plates, where they collect in a layer. The plates are periodically cleaned by a rapping system to release the layer into the ash hoppers as an agglomerated mass. In practice an ESP is divided into a number of discrete zones (up to five zones are commonly used). In most cases, the ESP is located after the air heater or economiser and referred to as a cold-side installation. In special cases, it is located before the air heater to take advantage of the higher temperature. In this case, it is called a hot-side installation.

Particles are removed from the gas stream in four stages:

- through application of an electrical charge to the dust
- through placement of the charged dust in an electrical field
- by capture (agglomeration) of the dust onto the collecting electrode
- by removal of the dust from the surface of the electrode.

The performance of an ESP follows the Deutsch Formula, which relates efficiency to the total surface area of the collecting electrodes, the volumetric flowrate of the gases and the migration velocity of the particles. Therefore, for a given dust, maximising the surface area of the collecting electrodes is very important, hence current practice is to use wide electrode spacing. This practice relies, in turn, on good rectifier design and control.

The industry uses good rectifier design, which includes the use of separate rectifier sections for each field or portion of a field of the ESP. This allows the applied voltage to be varied in the inlet and outlet zones to take account of the reduced dust load towards the outlet and gives the ability to operate the fields at progressively higher voltages without sparking. Good design is also practised by the use of automatic control systems. They maintain the optimum high voltage (HV) applied to the electrodes in a particular zone without sparking. An automatic monitor is used to apply the maximum voltage without sparking and constantly varies the HV. Fixed HV power supplies are unlikely to provide optimal collection efficiencies.

The resistivity (the inverse of the conductivity) of the dust is particularly important. If it is too low, the particles reaching the collector electrode lose their charge easily and dust re-entrainment can occur. When the dust has too high a resistivity, an insulating layer is formed on the electrode, which hinders normal corona discharge and leads to a reduction of the collection efficiency (back corona effect).

Particle size distribution affects the particle migration velocity. For particles >1µm, the migration velocity is inversely proportional to the particle diameter, becoming independent of particle size for particles <1µm**.** In addition, a high loading of fine particles can cause a substantial change in the electrical conditions in an ESP. Within the ESP, the particulate matter in the flue-gas is charged in an ionic space charge cloud. The nature of the space charge changes with the particle size distribution and the flue-gas loading. The particulate space charge increases with the number of particles per unit volume of flue-gas entering the ESP. An increase in fine particles and a relatively high particle migration velocity in the higher flue-gas loading can result in an increase in space charge, and can subsequently cause an electrical short circuit. The corona current at the inlet field can be suppressed by the increased space charge. A much higher space charge can result in the corona current being suppressed throughout the ESP.

Flue-gas flow distribution affects the overall performance of electrostatic precipitators. A uniform flue-gas velocity distribution is desirable throughout the entire cross-section since it ensures the maximum collection efficiency of the unit. To achieve the best performance from a precipitator, the gas flow through the units is optimised to give a uniform flow to prevent gas bypassing the electrical field. Correct design of inlet ducting and the use of flow distribution devices within the inlet mouthpiece can help an uniform flow to be achieved at the precipitator inlet.

Rapping, used to dislodge the fly ash (dust-cake) layer off the collection electrode into hoppers, may also cause re-entrainment. Particles are separated from the fly ash layer and re-entrained into the flue-gas. Re-entrainment can reduce the efficiency significantly. In effect, the ESP efficiency strongly depends on the unit size. An increase in efficiency incurs higher costs. The legislative demands for reduced emissions of fine particles have led to various research projects aimed at improving the efficiency of this technology.

A moderate sulphur content in the flue-gas decreases the resistivity of particles and enables better particle reduction. However, uneven gas distribution in the precipitator may lead to there being cooler parts inside the device. Also the higher the sulphur content of the fuel, the higher dew-point is possible. If these two conditions occur simultaneously, i.e. an uneven temperature distribution and a higher dew-point of sulphuric acid, there is a higher risk of material damages and hence a higher risk of the device breaking down.

Problems may also occur while burning fuels, which form volatiles, as the volatiles can coat the particles and hamper their effective precipitation. This is possible with low calorific value fuels, and when the boiler process is unstable.

The cost of electrostatic precipitators includes costs due to electricity consumption, maintenance expenses (strongly depending on the boiler process and fuel properties) and the conveying of the precipitated ash, but generally they are cost-effective devices for reducing particle emissions.

The initial investment costs may be higher or lower depending on applied fuel than for other available techniques such as bag filters. However, operational costs are smaller than the corresponding costs of the other techniques, and the use of modern control systems reduce these expenses even more. Operational costs can vary widely, depending on the different properties of fly ashes. Maintenance costs are normally very reasonable, when processing ordinary fly ash. These devices are competitive at power plants which have a wide range of power equipment and a variety of boiler processes.

3.2.2 Wet electrostatic precipitators

Wet electrostatic precipitators operate on the same principles as ESPs. In this case, the collected dust is removed from the collector plates by flushing with a suitable liquid, usually water, either intermittently or by continuous spray irrigation. They offer advantages for certain dusts that adhere to conventional plates or when other components in the gas stream interfere with the operation, for example in the case of a cool, damp gas. A liquid effluent is produced that requires further treatment. The wet ESP is only applied in new LCPs using heavy fuel oil and has been tested as the device for aerosol control.

3.2.3 Fabric filters (baghouses)

Fabric filtration is a method widely used worldwide to remove particles (especially fly ash) from the flue-gas of industrial and smaller combustion plants. However, the current trend is towards greater use of this technology for larger scale plants as well. In addition to collecting fly ash, there have been a number of applications where baghouses have been used together with the dry scrubbing-injection of slurried or powdered sulphur dioxide absorbent (such as lime or sodium bicarbonate) to simultaneously control both sulphur dioxide and fly ash emissions.

A fabric filter unit consists of one or more isolated compartments containing rows of fabric filter bags or tubes. Particle-laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags while the now cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. The major operating feature of fabric filters that distinguishes them from other gas filters is the opportunity to check the filtering surface periodically when cleaning.

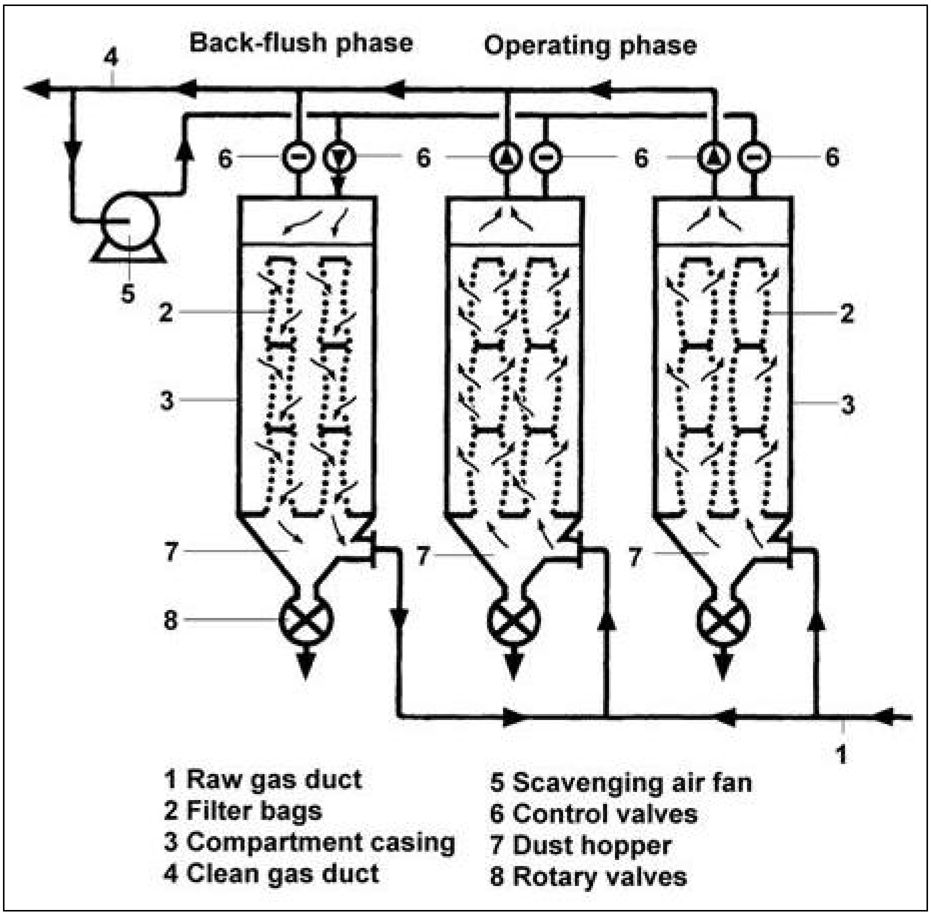


Figure 3.3: General arrangement of a fabric filter (with one compartment in the cleaning cycle) [36, Lurgi, 1999]

Regular dust removal from the fabric is important in order to maintain an effective extraction efficiency, but it also influences the operating life of the fabric. Fabric filters are normally classified according to the method by which the filter media are cleaned. The most common cleaning methods include: reverse airflow, mechanical shaking/deflating, vibration and compressed air pulsing. Acoustic horns are also used for the cleaning of bags. The normal cleaning mechanisms do not result in the fabric returning to its pristine condition and the particles deposited within the depth of the cloth help reduce the pore size between the fibres, resulting in high efficiencies with sub-micron particles.

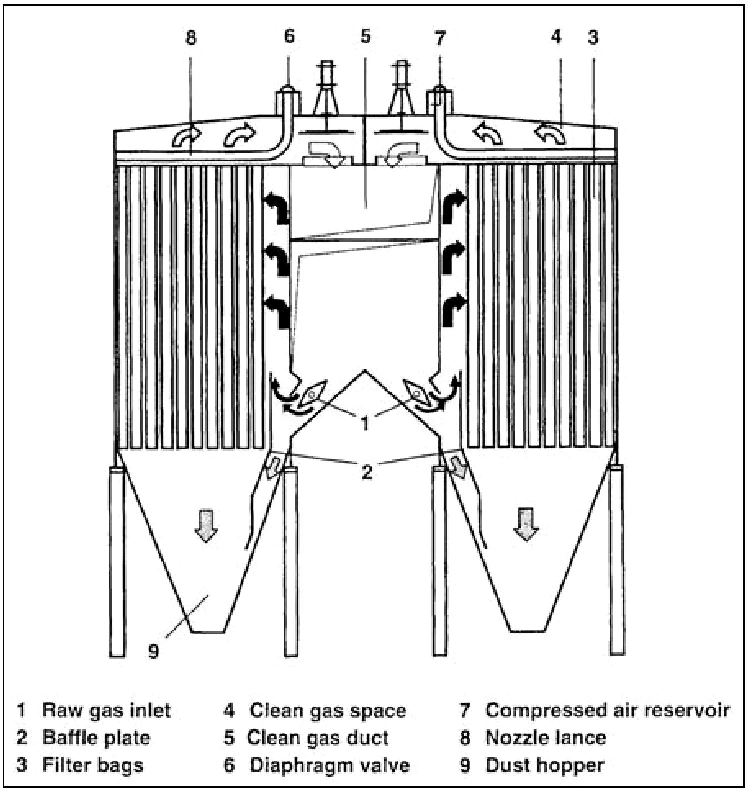


Figure 3.4: Low pressure pulse jet fabric filter
[36, Lurgi, 1999]

Fabric selection takes into account the composition of the gases, the nature and particle size of the dust, the method of cleaning to be employed, the required efficiency and economics. The gas temperature also needs to be considered, together with the method of gas cooling, if any, and the resultant water vapour and acid dew point.

Wear of the filter bags results in a gradual but measurable reduction in performance. There may also be a risk of damage or catastrophic failure of several bags if corrosion occurs, when abrasive material is filtered or when there is the danger of fire. Simple online monitoring systems, such as pressure drop indicators or dust tell tale devices, give only a rough indication of performance.

Triboelectric or optical devices are used to measure trends in the dust emissions from the fabric filter to identify possible failure. They can also be used to detect dust peaks during a cleaning cycle. When these measurements are integrated with a zoned cleaning system, any zone that contains damaged bags can be identified and local repairs can then be made [37, Robson, 1998].

Synthetic filter cloths such as Gore-Tex® and Tefaire® (teflon/fibreglass) have enabled fabric filters to be used in a wide range of applications and have led to an extended life of the filter. The performance of modern filter materials, even under high temperature or abrasive conditions, has improved recently. Cloth manufacturers can recommend the materials that are most suitable for specific applications.

In reverse gas and shake/deflate systems, new methods to increase the air to cloth ratio and to reduce the pressure drop are continually being investigated. Flue-gas inlet and outlet modifications aim to improve capture of the fly ash particles at the bottom of the baghouse whilst leaving the upper part clear to reduce obstructions in the flue-gas exit path.

In some countries, pulse jet technology has become the preferred fabric filter system as the primary particulate control device for utility and industrial boilers. Research is continuing to improve the understanding and hence performance of the system.

As there are many different filter materials on the market, the operator chooses the best one for his own needs. The filter material has to be selected with particular care to avoid possible problems being caused if the process parameters change.

Some fuels may cause clogging problems, which complicates the process operation. Clogging problems may occur, e.g. during start-ups, when oil is burned. The filter material is usually quite sensitive to the temperature of the ash and flue-gases, so unburned carbon and hot fly ash agglomerations may damage the filter material.

Also, cracks may form in the fabric material. These are difficult to detect during operation. These cracks increase the emissions of particles. If the baghouse is of a modular design and modules are isolated, then maintenance work may be possible without shutting down the process.

Maintenance costs are also high as the filter material has to be changed every two to five years. The minimum expense of the filter change is approximately 10 % of the investment cost. Precipitated material is easy to recycle, and, for example, unreacted sorbent can be returned into the process and have some economical value.

3.2.4 Centrifugal precipitation (cyclones)

This type of dust control system utilises gravitational forces and can process all types of flue-gases, in dry conditions. However, its performance characteristics limit its use to small- or medium sized installations, and only as a pre-collection technique when combined with other means for dust control.

A mechanical separator is composed of a set of cyclones (for example 31 x 24 with an individual diameter of about 240 mm to treat 700000 m^3/h of flue-gases at 130 °C) assembled in one or several housings. The gases to be purified are shared between the cyclones via a suitably designed chamber. The centrifuged dust agglomerates at the periphery of the cyclones and is driven towards the bottom of the apparatus where it falls into a hopper. In each cyclone, the pure air escapes towards the top via a central tube, is collected in an outlet chamber and then flows in the transport ducts.

Mechanical separators do not trap the fine dust. Thus, their efficiency is naturally limited to between 85 – 90 %. With boilers which burn lump coal on mechanical grates, cyclone technology is still in use because the quantity of fly ash is relatively small (20 % of coal ash compared with 80 % for pulverised fuel firing). Capture for the size range 5 – 10 microns is at or near 100 %. Capture does occur at smaller sizes, down to 1 micron but at a reduced capture efficiency. Cyclone ‘blow-down’ technology assists cyclones to achieve a higher efficiency particularly cyclones serving LCPs where many small cyclone cells operate in parallel.

Mechanical separators have the lowest investment cost of all the dust-extraction equipment. As this technique is not able to act alone as a fly ash control measure, the combined control technique will also have to be considered when calculating the investment costs. Operating costs include the energy necessary for the pneumatic or hydraulic removal of the collected ash and electric power to compensate flue-gas pressure loss of the equipment. Maintenance costs are reputedly low given the sturdiness of all of the components. The lifetime can be limited due to high erosion risk. [58, Eurelectric, 2001].

3.2.5 Wet scrubber

Wet scrubbers for control of particulate emissions have been in use for several decades. The low capital cost of wet scrubbers compared to that for ESPs and baghouses makes them potentially attractive for industrial scale use, though this may be offset by a relatively high pressure drop and operating costs. The flue-gas is cooled during wet scrubbing and requires reheating prior to emission to the atmosphere; this incurs higher energy costs. Partly due to such operating costs, the use of wet scrubbers for the control of particulate emissions has declined during the last decade. However, wet scrubbers have been used in some high temperature and pressure combustion applications such as integrated gasification combined cycle (IGCC) and pressurised fluidised bed combustion (PFBC). Here, the pressure drop experienced is less significant in relation to operating pressure, and in IGCC the problem of reheating is overcome as the gas is subsequently heated by combustion.

The majority of wet scrubbers for collecting fly ash from coal-fired furnaces (industrial or utility) are installed in the US. The greatest concentration of these units is the western US, where the available low sulphur coal is so highly resistive that ESPs are less economically attractive. Many of these scrubbers are designed for combined particulate removal and control of sulphur dioxide emissions, utilising the alkaline fly ash as sorbent. Lime is frequently added to boost SO_2 removal efficiencies.

Wet scrubbers comprise a group of particulate control devices which utilise a liquid to collect flue-gas particulate matter. The most common ones are venturi and moving-bed scrubbers.

The venturi scrubber is probably the most common wet particulate scrubber. In venturi scrubbers, the scrubbing liquid is introduced uniformly at the top of the converging section of the venturi as shown in the following Figure 3.5. The dust-laden flue-gas and the scrubbing liquid enter the venturi throat in which atomisation of the scrubbing liquid takes place through the velocity of the flue-gas alone.

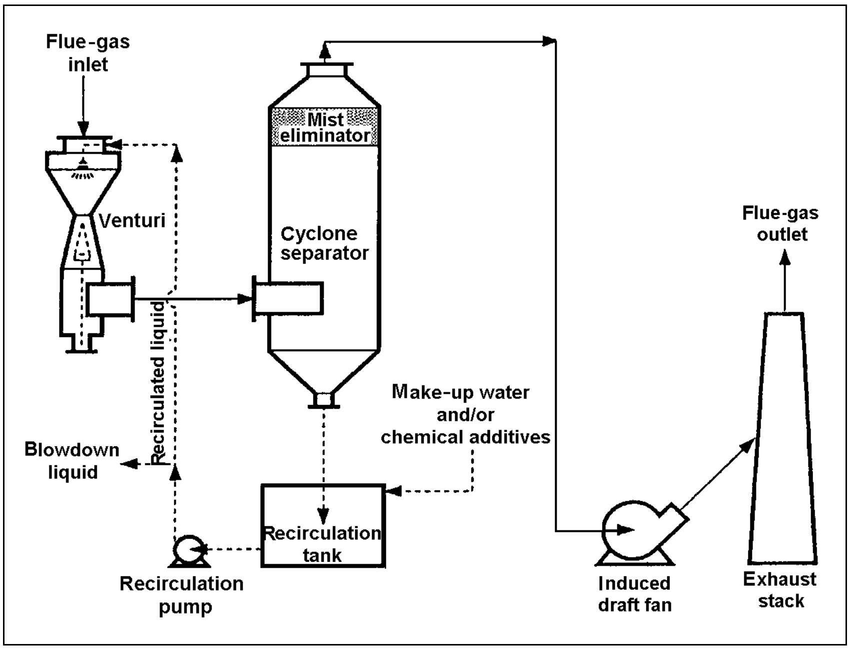


Figure 3.5: Typical flow diagram of a venturi system
[33, Ciemat, 2000]

Wetting of the flue-gas in this way leads to collection of small particles into larger heavier droplets, which are captured more easily in the separator. This overcomes the difficulties experienced in removing fine particles by inertial methods. A high initial relative velocity between the droplets and the particulates is required to ensure that the captured particles are retained on the droplets when the droplets have accelerated to their terminal velocity. The scrubbed gas and entrained droplets containing trapped particulates enter the diverging section where further collision and agglomeration take place.

Pressure drop and venturi performance is to a large extent dependent on gas velocity through the venturi. In order to accommodate efficient operation at reduced boiler loads, some venturis are designed with variable throats which can be operated close to a constant pressure drop, independent of the flue-gas flowrate (boiler load). The venturi itself is followed by a separating section for the elimination of entrained droplets.

Moving-bed scrubbers for particulate collection are packed with low density plastic spheres which are free to move within the packing retainers, as shown in Figure 3.6. Particulate collection may be enhanced by using several moving-bed stages in series. Moving-bed scrubbers commonly employ countercurrent flows. The packing is kept in constant motion by the flue-gas and the scrubbing liquid. Hence, the continued motion of the packing considerably reduces any tendency for the bed to plug.

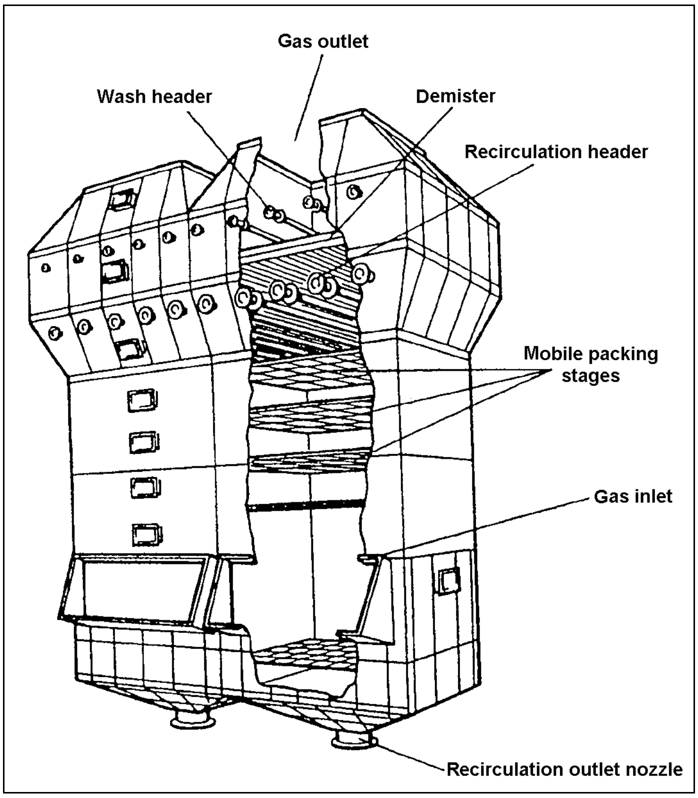


Figure 3.6: Moving bed scrubber
[33, Ciemat, 2000]

The separation efficiency is good when processing moderate dust loads. However, this technique is not very suitable for high ash content fuels.

If the mist eliminators do not work properly, there is a possibility that small water particles, including fly ash, may remain in the flue-gases even after the scrubbing. Large dust loads may cause clogging and can affect operational availability and effectiveness of the scrubber unit.

Investment costs are high and include: the reactor, a possible sorbent injection system and a waste water treatment plant. Operating costs are significant too, these mainly being related to water consumption and energy costs.

Condensing scrubbers cool the flue-gases, and the absorbed heat can be used, for example, for district heating. This improves the economics of the technique.

3.2.6 General performance of particulate matter control devices

Technology	Removal efficiency %				Other performance parameters		Remarks
	<1 µm	2 µm	5 µm	>10 µm	Parameter	Value	
Electrostatic precipitator (ESP)	>96.5	>98.3	>99.95	>99.95	Operating temperature	80 – 220 ºC (cold ESP) 300 – 450 ºC (hot ESP)	• the ESP has a very high efficiency, even for smaller particles • can handle very large gas volumes with low pressure drops • low operating costs, except at very high removal rates • can operate at any positive pressure condition • the ESP is not very flexible, once installed, to change operating conditions • it might not work on particulates with very high electrical resistivity.
					Energy consumption as % of electric capacity	0.1 – 1.8 %	
					Pressure drop	1.5 – 3 (10^2 Pa)	
					Residue	Fly ash	
					Off-gas flowrate	>200000 m^3/h	
					Applicability	Solid and liquid fuels	
					Market share	90 %	
Fabric filter	>99.6	>99.6	>99.9	>99.95	Operating temperature	150 ºC (polyester) 260 ºC (fibreglass)	• market share of 10 % is mainly based on application at CFB combustion and SDA • filtration velocities generally lie in the range 0.01 to 0.04 m/s according to the application, the filter type and the cloth • typical values used in power plant baghouses are 0.45 – 0.6 m/min for reverse-air, 0.75 – 0.9 m/min for shaker, and 0.9 – 1.2 m/min for pulse-jet applications • bag life decreases as coal sulphur content increases and as the filtering velocity increases • individual bags fail at an average annual rate of about 1 % of installed bags • the pressure drop increases as the particle size decreases for a given flue-gas throughput.
					Energy consumption as % of electric capacity	0.2 – 3 %)	
					Pressure drop	5 – 20 (10^2 Pa)	
					Residue	Fly ash	
					Off-gas flowrate	<1100000 m^3/h	
					Applicability	Solid and liquid fuels	
					Market share	10 %	
Cyclone	85 – 90 %. The smallest diameter of the dust trapped is 5 to 10 µm						• limited performance, can therefore only be used with other techniques for dust control
Wet scrubber (high energy venturi)	98.5	99.5	99.9	>99.9	Operating temperature		• as a secondary effect, wet scrubbers contribute to the removal and absorption of gaseous heavy metals • waste water is produced, which needs treatment and further discharge
					Energy consumption as % of electric capacity	up to 3 % (5 – 15 (kWh/1000 m^3))	
					Liquid to gas ratio	0.8 – 2.0 l/m^3	
					Pressure drop	30 – 200 (10^2 Pa)	
					Residue	Fly ash sludge/slurry	

Table 3.2: General performance of particulate matter cleaning devices
[35, ERM, 1996]

3.3 Techniques to reduce sulphur oxide emissions

Sulphur oxides are emitted from the combustion of most fossil fuels through oxidation of the sulphur contained in the fuel. Measures to remove sulphur oxides, mainly SO_2, from flue-gases during or after combustion have been used since the early 1970s, first in the US and Japan and then, in the early 1980s, in Europe. Nowadays there are many different ways of reducing the SO_2 emissions generated by the combustion of fossil fuels.

3.3.1 Primary measures to reduce sulphur oxide emissions

3.3.1.1 Use of a low sulphur fuel or fuel with basic ash compounds for internal desulphurisation

Switching to low sulphur fuel is a measure which can significantly reduce SO_2 emissions. In cases where supply is available, a change of fuel may be a viable option, this may include fuels with high internal desulphurisation due to the limestone (or other active compounds) content of the ash. For hard coal, 5 % of limestone is typical but not general. For lignite and peat may be higher with effects up to 80 % S control depending on fuel and combustion system. Also, biomass for co-combustion may contribute. However, this measure depends strongly on the type of fuel and the equipment used, and therefore will be discussed in Chapter 4 to Chapter 8.

Natural desulphurisation can be seen as an effect to reduce SO_2 emissions as high as 90 %, which occurs by burning some low quality lignites and peat with a low sulphur and a high alkaline ash content, resulting in very low SO_2 emissions, comparable to those achieved by application of common secondary techniques.

3.3.1.2 Use of adsorbents in fluidised bed combustion systems

The use of adsorbents in fluidised bed combustion systems are integrated desulphurisation systems. This limits the combustion temperature to about 850 °C. The adsorbent utilised is typically CaO, $Ca(OH)_2$ or $CaCO_3$. The reaction needs a surplus of adsorbent with a stoichiometric ratio (fuel/adsorbent) of 1.5 to 7 depending on the fuel. Due to chlorine corrosion effects, the desulphurisation rate is limited by 75 %. This technique is mainly utilised in coal-fired LCPs and is described in Chapter 4.

3.3.2 Secondary measures to reduce sulphur oxide emissions

The common flue-gas desulphurisation (FGD) technologies can be classified as shown in Figure 3.7.

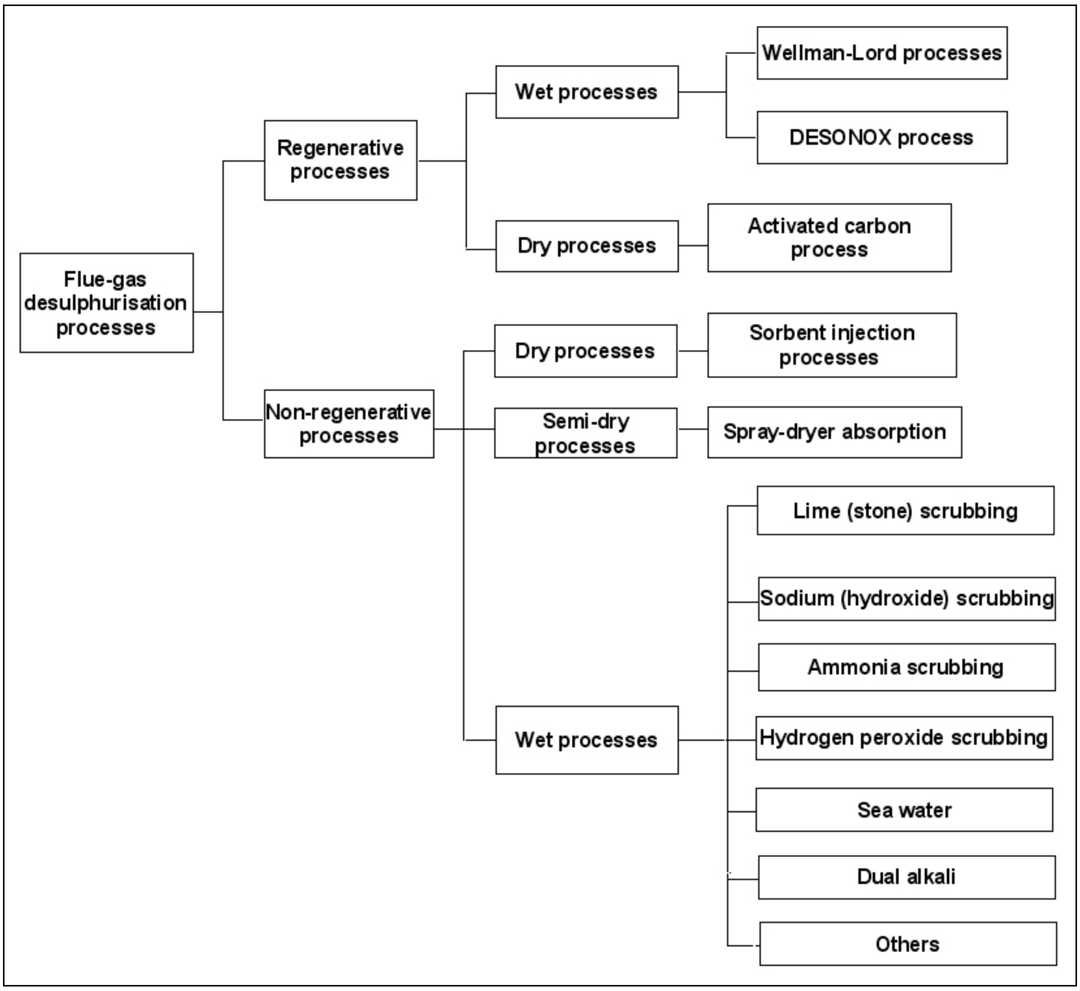


Figure 3.7: Overview of technologies used to reduce sulphur oxide emissions (secondary measures)

Up to the year 2000, there were 680 FGD systems installed in twenty seven countries worldwide and 140 currently under construction or planned in nine countries. [38, Soud, 2000] With data collected by EURELECTRIC, VDEW and VGB up to 1996, an overview of desulphurisation is presented in Table 3.3 with estimates for further applications up to the end of 1999.

Plants and technique	Number of sites and electrical power		Plants with FGD and controlled electrical power	
Country	No of sites	MW_e	No of sites (N 1)	Electrical. power (MW_e)
Austria	18	4852	13	3415
Belgium	31	5867	2	1480
Denmark	13	8447	10	5389
Germany	960 (N2)	91090	185	42000
Greece	10	6138	1	300
Finland	94	8900	46	3970
France	17	18218	3	2400
Ireland	10	2955	-	-
Italy	79	41873	15	6660
Luxembourg	-	-	-	-
Netherlands	15	9632	5	2690
Portugal	6	4514	-	-
Spain	41	19357	11	2373
Sweden	41	5303	6	1164
United Kingdom	26	37718	10	9996
EU-15 (1996)	1361	264864	307	81837

Notes:
N1 including fluidised bed combustion
N2 including German industrial power plants >50 MW_{th})
The present implementation of FGD systems is mainly due to power plants firing fuels with a certain S-content (e.g. coal, fuel oil). FGD systems are typically not required in natural gas fired power plant.

Table 3.3: FGD at large combustion plants in EU-15
[58, Eurelectric, 2001], [192, TWG, 2003]

3.3.3 Wet scrubbers

Wet scrubbers, especially the limestone-gypsum processes, are the leading FGD technologies. They have about 80 % of the market share and are used in large utility boilers. This is due to their high SO_2 removal efficiency and their high reliability. Limestone is used in most cases as the sorbent, as it is available in large amounts in many countries and is cheaper to process than other sorbents. By-products are either gypsum or a mixture of calcium sulphate/sulphite, depending on the oxidation mode. If the gypsum can be sold, total overall operating costs may be reduced.

Sodium scrubbing was popular in the late 1960s in Japan. The by-product, sodium sulphite, was sold to the paper industry. The sodium scrubbing process is simple and was applied to a large number of small oil-fired boilers. Several magnesium-scrubbing systems are also used in relatively small industrial boilers because of the low capital costs involved. In magnesium scrubbing systems, waste water containing magnesium sulphate can be discharged into the sea, after the removal of dust and dust-absorbed heavy metals, as magnesium sulphate is already a constituent of seawater. The process, therefore, has an advantage over other systems, if a plant is located near the coast. The by-product of wet ammonia scrubbers can be used as an agricultural fertiliser.

Dual alkali processes have been in operation commercially in the US since the mid 1970s. Wet limestone scrubbers suffered from gypsum scaling problems during their development, from the 1970s to the early 1980s, due to the lack of understanding of the scrubber chemistry and the process design requirements. Dual alkali was used while system manufacturers and plant operators solved the scaling problems. Recent developments in dual alkali processes, enabling the use of limestone instead of the more expensive lime sorbent, and the production of gypsum, may revive the use of this system.

3.3.3.1 Wet lime/limestone scrubbers

The first successful wet lime scrubber plant was constructed in 1972 by Mitsui Miike Engineering Company (MIMC) at the Omuta coal-fired plant of Mitsui Aluminium in Japan. The plant used lime slurry and produced a sludge of calcium sulphite/sulphate and fly ash, which was disposed of in a pond. Since then, wet lime scrubbers have become popular in the US but not immediately in other countries, mainly because of the requirement for large areas of land for sludge disposal. The first wet limestone scrubber plant producing gypsum for a coal-fired utility boiler was constructed by MMEC at the Takasago power plant of EPDC (Electric Power Development Company), which started operation in 1975. Initially the plant had start-up problems but the reliability of the operation has exceeded 99 % since 1977.

Today wet limestone scrubbers are the most widely used of all the FGD systems, with a share of c. 80 % of all the installed FGD capacity. Figure 3.8 shows a typical flow diagram of a recent type of wet lime/limestone FGD system. Limestone is commonly used as a reagent because it is present in large amounts in many countries and is usually around three or four times cheaper than other reagents. Lime was commonly used as a reagent in earlier plants because of its better reactivity with SO_2. However, lime has been replaced by limestone to reduce the risk of lime calcination which is energy intensive, costly, and time consuming to repair. Nevertheless in some cases, lime has to be used instead of limestone due to the whiteness requirements of the FGD gypsum users. In any case, FGD using limestone could achieve almost the same SO_2 removal as lime. The reactivity of limestone has an important influence on the efficiency of a FGD system; however, at the present time there is no standard or normalised method to test reactivities. Other reagents, such as magnesium-enhanced lime, are also used.

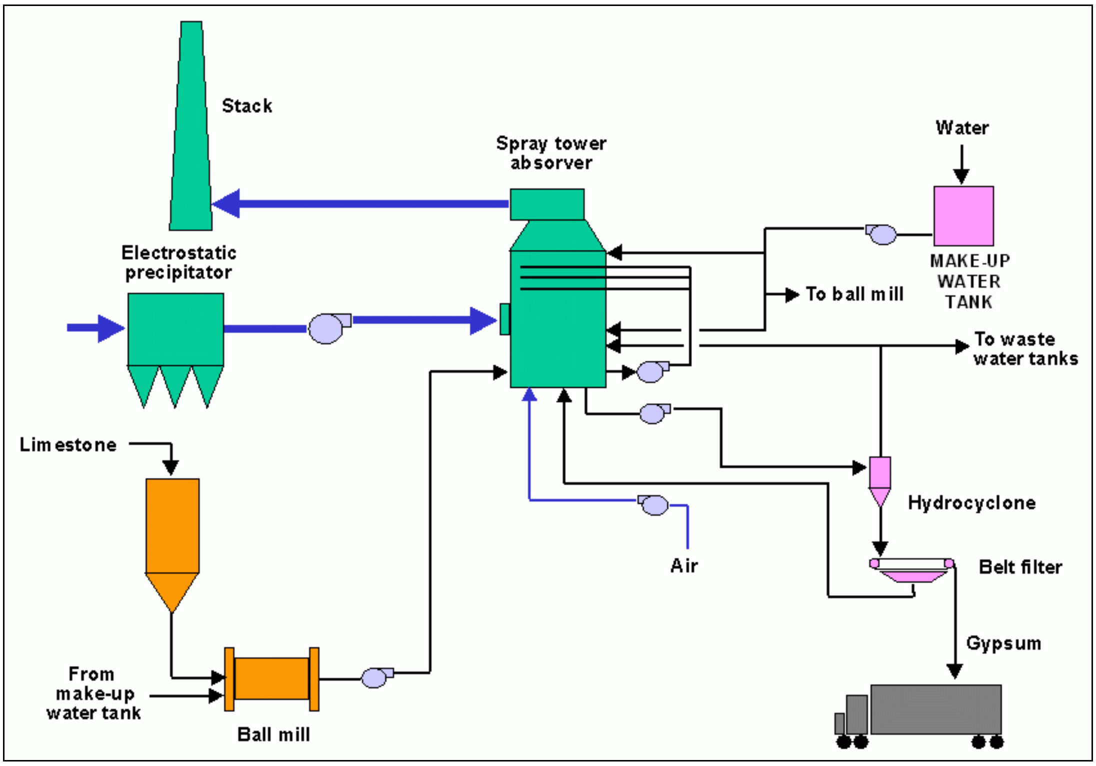


Figure 3.8: Schematic flow diagram of a lime/limestone wet scrubber FGD process

The flue-gas leaving the particulate control system usually passes through a heat-exchanger and enters the FGD absorber, in which SO_2 is removed by direct contact with an aqueous suspension of finely ground limestone whereas limestone should have more than 95 % of $CaCO_3$. Fresh limestone slurry is continuously charged into the absorber. The scrubbed flue-gas passes through the mist eliminator and is emitted to the atmosphere from a stack or a cooling tower. Reaction products are withdrawn from the absorber and are sent for dewatering and further processing.

The wet limestone scrubber is generally divided into two categories according to the type of oxidation: forced oxidation and natural oxidation mode. The mode of oxidation is determined by the chemical reactions, the pH of the reagent slurry and the resulting by-product. In forced oxidation mode with a pH range of 5 to 6, which is common in wet limestone scrubbers, the chemical reactions are as follows:

$$\mathbf{SO_2 + H_2O \rightarrow H_2SO_3} \qquad (1)$$

$$\mathbf{CaCO_3 + H_2SO_3 \rightarrow CaSO_3 + CO_2 + H_2O} \qquad (2)$$

$$\mathbf{CaSO_3 + ½O_2 + 2H_2O \rightarrow CaSO_4 \bullet 2H_2O} \qquad (3)$$

$$\mathbf{CaCO_3 + SO_2 + ½O_2 + 2H_2O \rightarrow CaSO_4 \bullet 2H_2O + CO_2} \qquad (4)$$

$$\mathbf{CaSO_3 + ½H_2O \rightarrow CaSO_3 \bullet ½H_2O} \qquad (5)$$

Reactions (1) and (2) are common to all wet FGD systems. Reaction (3) shows the forced oxidation of calcium sulphite by air and the formation (crystallisation) of calcium sulphate dehydrate or gypsum in the oxidation mode. In forced oxidation mode, air is introduced into the bottom of the absorber to oxidise calcium sulphite to calcium sulphate, achieving over 99 % oxidation.

In natural oxidation mode, calcium sulphite is partly oxidised by the oxygen contained in the flue-gas. The main product is calcium sulphite hemi-hydrate (5). The produced mixture of calcium sulphite hemi-hydrate and gypsum is in a sludge form.

At the lower pH range of 4.5 to 5.5, the chemical reaction is different. After SO_2 absorption (1), the primary product of the neutralisation by limestone is not calcium sulphite, but calcium bisulphite $Ca(HSO_3)_2$

$$\mathbf{CaCO_3 + 2H_2SO_3 \rightarrow Ca(HSO_3)_2 + CO_2 + H_2O} \qquad (6)$$

$$\mathbf{Ca(HSO_3)_2 + ½O_2 + H_2O \rightarrow CaSO_4 - 2H_2O + SO_2} \qquad (7)$$

Calcium bisulphite is much more soluble than calcium sulphite. Hence, operation in the lower pH range has less risk of scaling and plugging. Calcium bisulphite is oxidised and crystallised to form gypsum or calcium sulphate dehydrate (7).

Table 3.4 shows a comparison between the forced oxidation and natural oxidation modes in the wet limestone scrubber. In forced oxidation, dewatering is easy because the gypsum crystals are relatively large. The primary dewatering is usually accomplished by hydro-cyclones followed by secondary dewatering in filters or centrifuges. The final product, containing about 90 % solids, is easy to handle and is either sold mainly as gypsum for plaster, cement, and wallboard, replacing natural gypsum utilised to fill mines or landfilled. Selling the gypsum may contribute to an overall reduction of the total operating costs. Saleable gypsum, however, requires washing during a secondary dewatering to remove soluble salts such as chlorides.

Mode	By-product	Size of by-product crystal	Use of by product	Dewatering	Reliability	Region used
Forced oxidation	Gypsum 90 % water 10 %	0 – 100 µm	Wallboard, cement, etc.	Easy hydro-cyclone plus filter	>99 %	Europe and Japan
Natural oxidation	Calcium sulphate/sulphite 50 – 60 % water 50 – 40 %	1 – 5 µm	No use (landfill)	Not easy – thickener plus filter	95 – 99 % due to scaling problems	US

Table 3.4: Comparison between forced and natural oxidation

The by-product from the natural oxidation mode is a mixture which is difficult to dewater. This mixture is calcium sulphite hemi-hydrate and calcium sulphate dehydrate. Primary dewatering therefore requires a thickener. Secondary dewatering is undertaken with filters or centrifuges. The final by-product remains 40 – 50 % water. In many cases it is ponded or landfilled but needs blending first with fly ash and lime because of its thixotropic nature. The natural oxidation process is applied mainly in the US. Its reliability has been improved but still remains only about 95 - 99 % due to gypsum scaling problems. There is a tendency to convert from natural oxidation to forced oxidation because the gypsum is better quality than the sludge, even for landfill purposes.

The configuration of wet limestone scrubbers can be generally classified into four types (a, b, c and d) as shown in Figure 3.9. Both c and d are shown here in forced oxidation mode, but could be changed to natural oxidation and hence to the sludge residue by eliminating air entry in the oxidation vessel.

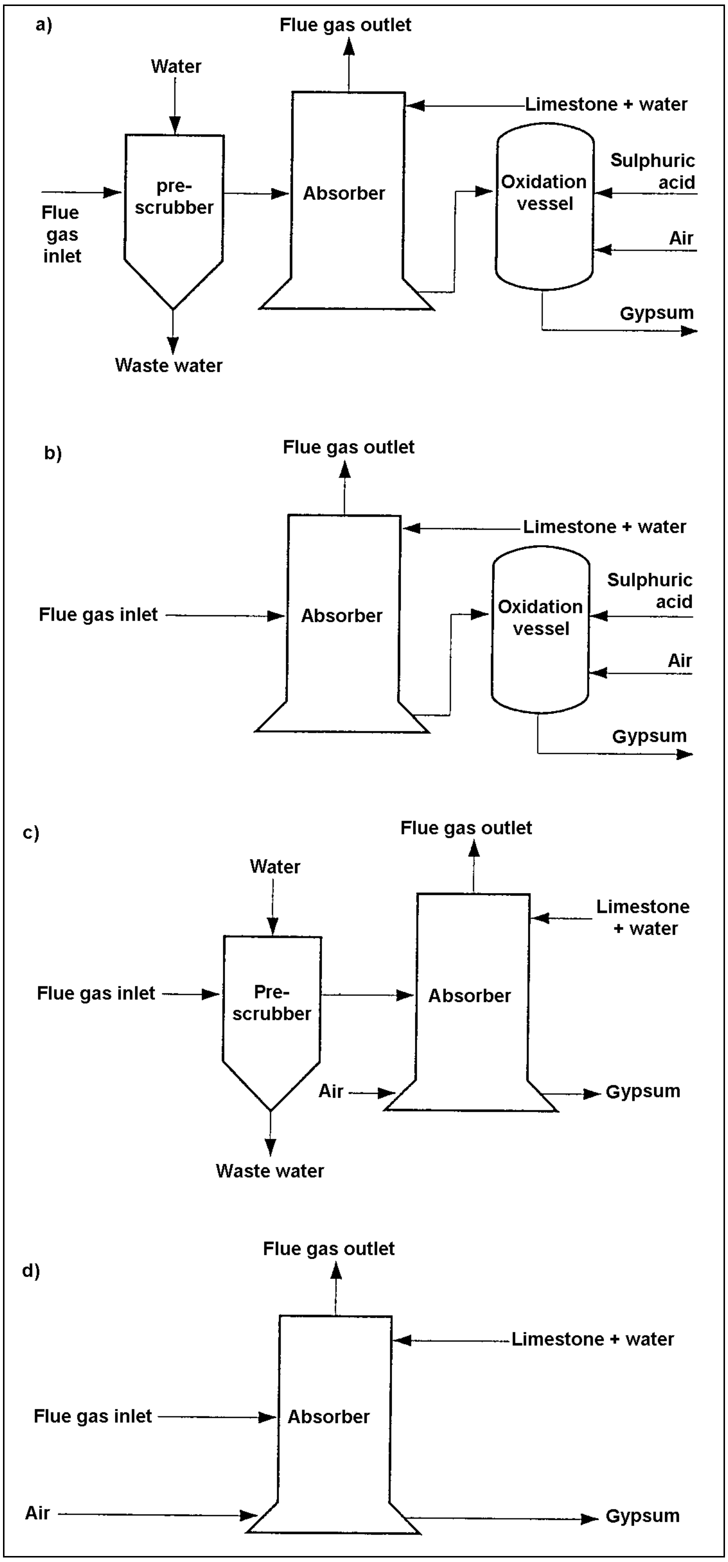


Figure 3.9: Different types of lime/limestone wet scrubbers
[38, Soud, 2000]

Type (a) and **type (b)** use an additional oxidation vessel and are not presented and discussed here, because oxidation vessels have only been used in research development and are not applied anymore today.

Type (c) does not have a separate oxidation vessel. Here, the oxidation air is purged into the bottom of the absorber to form gypsum. This oxidation method is usually called *in situ* oxidation and is now the most common method. When oxidation occurs in an oxidation vessel, such as with types (a) and (b), the process is called *ex situ* oxidation. Although the pre-scrubber is primarily to remove HCI and HF, a low pH pre-scrubber also removes more mercury, as well as any fine particulates which may be carrying other trace elements. In Japan, many of the new large FGD plants have adopted type (c) because of the high quality gypsum that results and its high operational reliability, avoiding possible problems which may occur without the pre-scrubber.

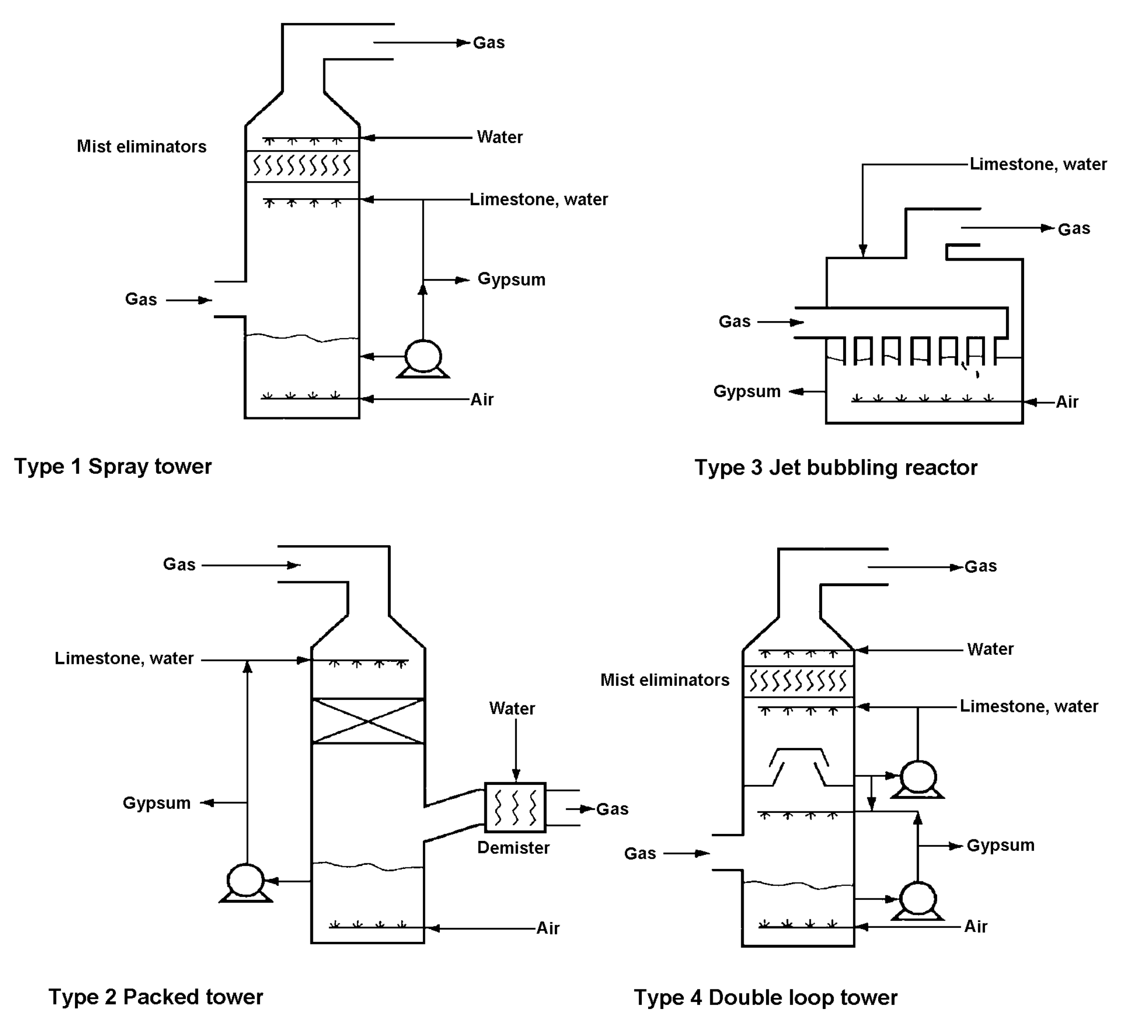
Eliminating the oxidation vessel or conversion from *ex situ* to *in situ* oxidation is a major development in FGD technology. *In situ* oxidation has many advantages over *ex situ* oxidation.

- first of all, *in situ* oxidation prevents scaling and plugging problems through complete oxidation of the product in the absorber, resulting in a higher reliability of operation. Partial oxidation of the product, due to the oxygen in the flue-gas, causes gypsum scaling in the absorber
- secondly, *in situ* oxidation achieves a higher SO_2 removal efficiency compared with *ex situ* oxidation
- thirdly, it is important to note that *in situ* oxidation promotes SO_2 removal efficiency even at low pH values because the H_2SO_4, which is produced by oxidation of H_2SO_3 through air injection, rapidly reacts with limestone. In addition, the utilisation of limestone is higher than in *ex situ* oxidation because of the higher solubility of limestone at low pH values. The Ca/S molar ratio ranges from 1.01 to 1.05.

A further advantage of *in situ* oxidation is that it is possible to reduce the formation of S_2O_3. This is a by-product of the side reaction of SO_3 oxidation and is one of the Chemical Oxygen Demand (COD) substances. Decreasing the COD to as low as one-fifth to one-tenth in the waste water can reduce the waste water treatment capacity. There is also no need to add H_2SO_4 for oxidation, unlike with types (a) and (b). The emergence of *in situ* forced oxidation has made the wet limestone scrubber more attractive.

Type (d) is the simplest configuration in wet limestone scrubbers and has now become the leading FGD system. All chemical reactions are operated in an integrated single absorber. This can reduce the capital cost and the power consumption. Type (d) has achieved a high reliability of operation and has produced a reasonable quality of gypsum since the late 1980s. An integrated single tower also requires less space, facilitating the retrofit to existing boilers. In Germany, the most recent FGD installations are type (d). In the US, type (d) is also popular due to its lower costs and high efficiency.

The design of the absorber is crucial in wet FGD systems. Figure 3.10 shows examples of different types of absorbers where all FGD chemical reactions occur together.



Type 1 Spray tower

Type 3 Jet bubbling reactor

Type 2 Packed tower

Type 4 Double loop tower

Figure 3.10: Different absorber types
[33, Ciemat, 2000]

Type 1 is the spray tower absorber and is the most commonly used in wet FGD systems throughout the world. The spray tower normally has three to four spray heads with a number of spray nozzles through which an aqueous suspension of finely ground limestone is atomised and sprayed with uniform distribution. The flue-gas introduced into the absorber is in close contact with freely moving droplets, usually in a countercurrent configuration with no gas flow restricting devices. Liquid mists carried over are captured by mist eliminators. This design was developed to cope with the scaling problems of the first generation of FGD equipped with internally structured absorbers.

Type 2 is the packed tower absorber using plastic grid packing, originally developed in Japan. The packed tower lengthens the residence time for gas-liquid contact, resulting in higher SO_2 removal efficiencies. The packed tower is now operated without scaling problems, due to an improved understanding of FGD processes. Moreover, the important feature of the high velocity co-current gas flow configuration is a compact design for the large-scale absorber.

Type 3 is known as the turbulent bubble bed reactor. The flue-gas is injected into a slurry through numerous submerged pipes while limestone slurry is fed into the turbulent bubble bed reactor and air for oxidation is blown into the slurry. The absorber type is a good example of a simplified FGD process. It eliminates the need for recycle pumps, spray nozzles and headers, separate oxidation tanks and thickeners, thereby minimising difficulties as well as power consumption.

Type 4 uses a double-loop concept, originally pioneered in the US. This absorber is in two loops described as a quencher and absorber, each having different pH values with each function. A number of plants using this type of absorber have been installed in Canada, Germany and the US.

Wet limestone FGD systems naturally suffer from an aggressive operating environment, leading to corrosion, erosion and abrasion. The flue-gas path from the inlet of the absorber to the stack discharge must be protected, for instance by using rubber or flake linings, against acid attack caused by the adiabatic cooling and saturation of the gas. The components of particular concern are the inlet duct, absorber, outlet duct reheat systems and the stack liners. All slurry-handling parts are subject to both corrosive and abrasive attack. These include absorber spray zones, tanks, agitators, pumps, pipes, valves and all dewatering equipment.

The flue-gas temperature is reduced to about 45 – 80 ºC by passing it through the wet FGD units. To improve dispersion of the clean flue-gas from the stack and to reduce the frequency of a visible plume, regulations require a minimum flue-gas temperature at the stack outlet, for example, 80 ºC in the UK. To reach this requirement the flue-gas needs to be reheated. The regenerative gas-gas heat-exchanger (reheater) is most commonly used to reheat the flue-gas. Some new regulations do not require a minimum temperature at the stack any more. Furthermore, clean flue-gas discharge via a wet stack has less electrical power demand, although there is visible plume effect.

Dispersion models have shown that the stack height is much more important for flue-gas dispersion than the discharge gas buoyancy, to ensure a low impact on air quality near to the site, without a reheating of the flue-gas. The discharge gases buoyancy (and hence dispersion) can be increased if necessary by reheating the flue-gas, but dispersion can also be improved by having a higher stack exit velocity.

The application of a wet FGD system requires considerable space. In existing plants, where FGD was possibly not included as part of the process, there may be a lack of available space and extra duct work may be needed, which will incur much higher investment costs (therefore the system may need to be designed and implemented on a case-by-case basis).

Moreover, when implementing this process on an existing installation, a new stack may need to be built, because the exhaust gases from the FGD are much more corrosive (the dew point is reached in the scrubber) than without FGD treatment, and the existing stack may not be designed or suitable for this purpose. These new stacks can take advantage of modern flue linings that both reduce acid condensate and improve dispersion by heating up quickly during start ups. This is becoming increasingly important as the electricity market results in operating plants more adapted to the demand.

Wet scrubber processes have undergone considerable development in the last few decades, leading to improved reliability and removal efficiencies, as well as reduced costs. Reliability is normally over 99 % with forced oxidation, and 95 – 99 % with natural oxidation. The applicability may be influenced by both scrubber components and auxiliary processes connected to the absorber process.

A process involving hydroxide and sulphide precipitation, clarification and slurry dewatering has been found to be a good measure for the waste water treatment after the FGD plant to remove heavy metals and suspended solids.

There is little published data available on the actual costs of wet scrubber installations from either manufacturers or users. A full evaluation of the scant available published data is also difficult, due to the lack of information on how the costs have been calculated.

The capital costs are relatively high for a wet limestone scrubber, but, on the other hand, the operating costs are moderate due to the advanced automation, reliability and as a saleable by-product. The capital costs can vary widely. They depend on the site specifications and technical and economic conditions such as plant size, SO_2 inlet concentration, SO_2 emission limits, the redundancy strategy, annual operating hours, operating years, management of gypsum or residues, interest rates, number of units on site, FGD market situation, etc. The capital cost for the wet lime/limestone scrubber process is mainly influenced by the flue-gas flowrate. FGD retrofit installations are much more expensive than green field installations. The capital costs for a wet limestone scrubbing process varies from EUR 35 – 50 per kW_{el}, and the operation and maintenance costs are between EUR 0.2 – 0.3 per kWh (energy input). The typical SO_2 removal costs are between EUR 750 – 1150 per tonne of SO_2 removed, and the effect on the price of electricity EUR 3 – 6 per MWh (electricity produced).

Concerning desulphurisation of flue-gases from liquid fuel fired engines, a larger diesel engine for example, has an oxygen content of about 13 – 15 vol-% O_2 in the flue-gas (air factor 2.7 - 3.5). A boiler plant has typically 3 – 6 vol-% O_2 (air factor 1.2 – 1.4) dependent on the used fuel. A higher oxygen content means a larger exhaust gas flow and need for a larger FGD reactor system, which leads to a higher investment cost per kW_{el}, than mentioned above

3.3.3.2 Seawater scrubber

Seawater scrubbing utilises seawater's inherent properties to absorb and neutralise sulphur dioxide in flue-gases. If a large amount of seawater is available near a power plant, it is most likely to be used as a cooling medium in the condensers. Downstream of the condensers the seawater can be re-used for FGD. The basic principles of the seawater scrubbing process can be seen in Figure 3.11.

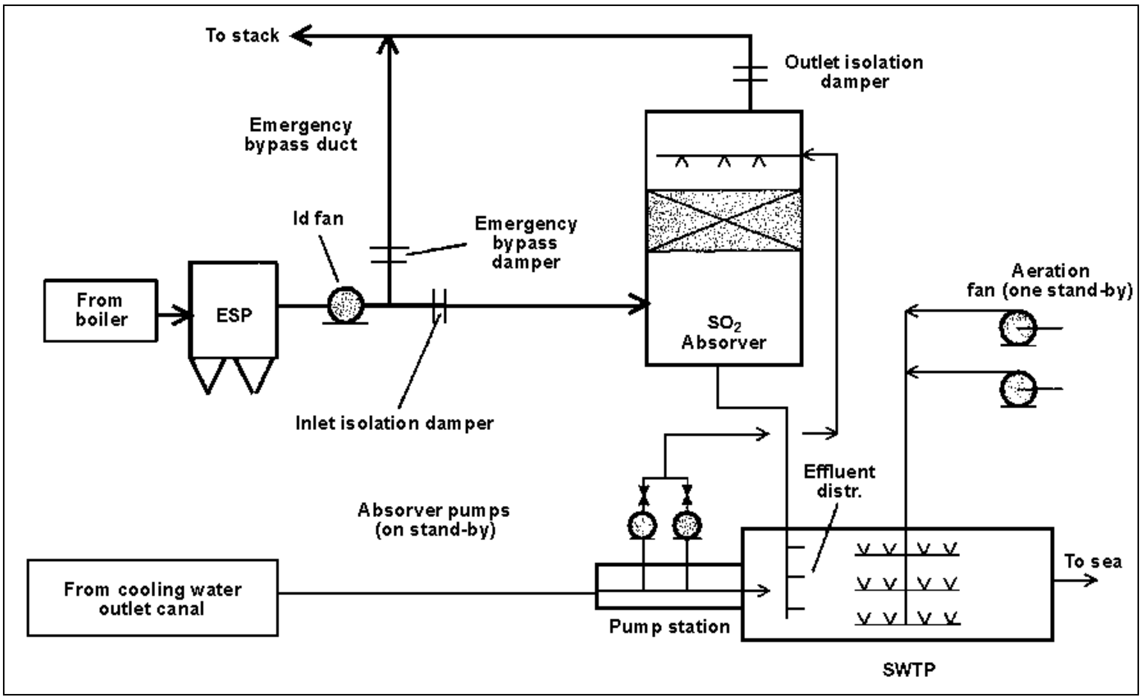


Figure 3.11: Basic principles of the seawater scrubbing process
[39, ABB, 2000]

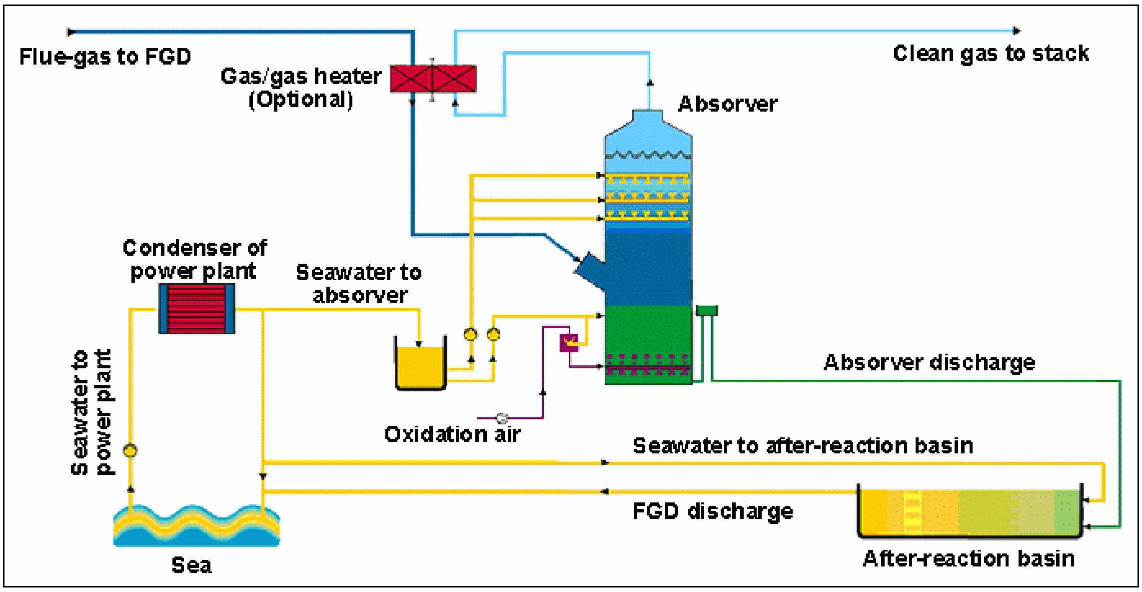


Figure 3.12: Seawater scrubbing process
[192, TWG, 2003]

The basic process can be seen in Figure 3.11 and Figure 3.12.The flue-gas from the power plant leaves the dust collector, normally a fabric filter or an electrostatic precipitator. The flue-gas is then fed to the SO_2 absorber, where it comes into contact with a controlled proportion of the seawater, taken from the cooling water outflow of the steam turbine condenser. Due to the presence of bicarbonate and carbonates in the seawater, the sulphur dioxide of the flue-gas is absorbed. The acidified absorber effluent is mixed with additional seawater to ensure that the pH is at optimal level for the oxidation process. The introduced air forces the oxidation of the absorbed sulphur dioxide from bisulphite to bisulphate and removes dissolved CO_2. The water will be nearly saturated with oxygen and the pH value will be restored to neutral before the seawater is discharged back to the sea.The seawater process does not involve any import or export of reagents or solid by-products. It only uses seawater that has already been used in the power generation process as cooling water of the steam turbine condenser.

The process is based on the following chemical reaction:

$$\mathbf{SO_2 + 2HCO_3- + ½O_2 \text{-->} SO_4^{2-} + 2CO_2 + H2O}$$

The seawater scrubbing process uses the cooling water downstream of the power plant condensers. A part of the seawater is pumped to the absorber top, flowing through the packing, where it absorbs the SO_2. The acidified seawater collects in the absorber sump and flows by gravity to the seawater treatment plant (SWTP). The acidified absorber effluent is mixed with the rest of the cooling water in a special mixing unit in the SWTP front section, prior to the next step which is oxidation. Ambient air is in this section blown into the seawater by heavy-duty industrial fans. The SO_2 will then be converted to sulphate (SO_4^{2-}), the water will be nearly saturated with oxygen and the pH 6 level will be adjusted normally, because this is the lower limit of the World Bank guideline, before the seawater is discharged back to the sea.

3.3.3.3 Magnesium wet scrubber

The reagent in magnesium scrubbing is magnesium hydroxide, which is produced by adding slaked lime to seawater in order to enhance alkalinity. The process has become popular since the early 1980s, replacing sodium scrubbing, because magnesium hydroxide has become less costly than sodium hydroxide or carbonate as the reagent. It produces waste sulphate liquor. A number of units with this process have been constructed, mainly for industrial coal-fired boilers. The magnesium wet scrubber has mainly been applied to smaller plants, i.e. less than 50 MW, and will, therefore, not be further described in this document. One aspect of the process is that the magnesium sulphate can be discharged into the sea because magnesium sulphate is a constituent of seawater. The capital costs are low, but the operational costs are high. This process is suitable only for plants located near the coast.

3.3.3.4 Ammonia wet scrubber

In the ammonia wet scrubber, as shown in Figure 3.13, SO_2 is absorbed by aqueous ammonia, resulting in ammonium sulphate as the fertiliser by-product. However, there is an excess of this fertiliser from other sources in industrialised countries. Hence, the process is seldom used, although in China three units with this process totalling about 200 MW_e have been installed since 1987 on oil-fired boilers.

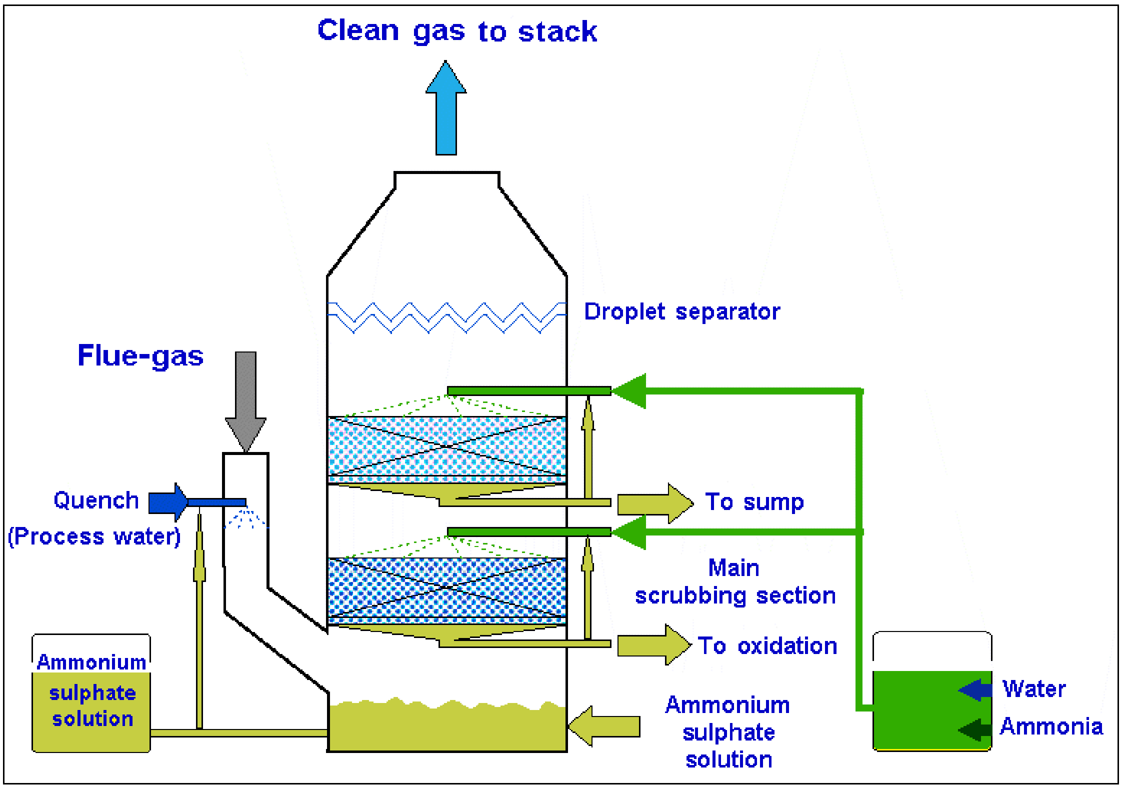


Figure 3.13: The wet ammonia process
[126, Lurgi Lentjes Bischoff, 2001]

The process has been operated on a coal-fired, wet bottom boiler of 191 MW_e firing capacity in Germany. It has been operating reliably following improvements and the solution of initial problems such as the generation of aerosols, that is, ammonia salt particles with a diameter of up to 1 µm. The process has been chosen to satisfy the criteria for emission limits of less than 200 mg/Nm^3. Besides this, the driving force to apply the wet ammonia process has been the requirement for a saleable by-product, the requirement that no waste water results (the special local conditions do not allow discharge of waste water into the public watercourse) or other materials that would require waste disposal, as well as considerations of the very limited space availability and economic constraints.

3.3.4 Spray dry scrubbers

In the worldwide hierarchy of applied FGD systems, spray dry scrubbers have the second place behind wet scrubbers. Lime slurry is usually used to remove SO_2 from the flue-gas in this type of FGD. SO_2 removal efficiencies and operational reliability have all improved as this technology has matured. Spray dry scrubbers are generally characterised by lower capital costs but have higher operating costs than wet scrubbers, mainly due to the use of the more expensive sorbent lime. Spray dry scrubbers are mostly used for relatively small to medium capacity boilers using low to medium sulphur (1.5 %) coal. For the same reason, they are preferable for retrofits and for peak load operation. The residue is normally a mixture of calcium sulphite, calcium sulphate and fly ash, which is less attractive commercially. Tests have been carried out to investigate the possibility of industrial use of the residue. Some installations use a particulate control device before the spray dry scrubber for separate collection of the fly ash.

The spray dry scrubber is an associated FGD technology, developed in the US and in Europe in the early to mid-1970s. The first commercial use in combustion plants started in the US in 1980, where the technology was applied to a coal-fired boiler.

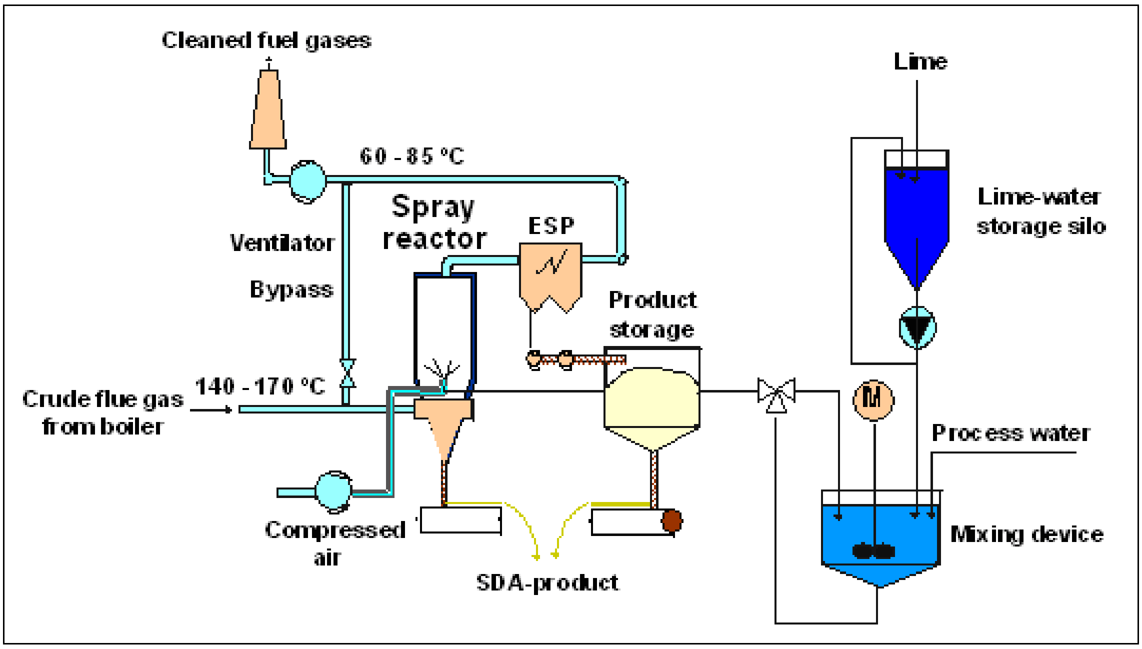


Figure 3.14: Flow sheet of a spray dry scrubber process
[58, Eurelectric, 2001]

The process consists mainly of the spray dry absorber; particulate control, such as an ESP or a fabric filter; and recycling disposal devices for the reaction products. Several spray dry scrubber processes are currently commercially operated. These processes are similar to each other in terms of the process configuration, constituents, and the sorbent used, but one difference is the lime slurry dispersion system used in the spray dry absorber.

The sorbent for SO_2 absorption is typically lime or calcium oxide. Lime is mixed with an excess of water or is slaked to produce lime slurry, which is also called lime milk. Lime slurry is atomised to a cloud of fine droplets in the spray dry absorber where SO_2 is also removed from the flue-gas. Water is evaporated by the heat of the flue-gas, usually with a sufficient residence time (about 10 seconds) for the SO_2 and other acid gases such as SO_3 and HCl to react simultaneously with hydrated lime to form calcium sulphite/sulphate and calcium chloride. Waste water treatment is not required in these processes because all the water is completely evaporated in the spray dry absorber.

The process chemistry associated with SO_2 removal from the flue-gas is a simple acid/base absorption reaction between SO_2 and hydrated lime as follows:

$$\mathbf{Ca(OH)_2 + SO_2 \rightarrow CaSO_3 + H_2O}$$

$$\mathbf{CaSO_3 + ½O_2 + ½H_2O \rightarrow CaSO_4 \cdot ½H_2O}$$

The absorption chemistry is strongly affected by factors such as flue-gas temperature, gas humidity, SO_2 concentration in the flue-gas and atomised slurry droplet size. The by-product is a dry mixture of calcium sulphite, sulphate, fly ash and unreacted lime. Although the spray dry scrubber process is sometimes called a semi-dry process because it uses lime slurry (mixture of lime and water), the residue is dry powder, which is collected by either the ESP or the fabric filter. As this residue contains some unreacted lime, part of it is generally recycled and mixed with fresh lime slurry to enhance lime utilisation.

The use of a pre-collector which removes most of the fly ash before it enters the absorber is a common design feature of most European spray dry scrubber plants. It is installed between the air heater and the absorber. The installation of a pre-collector has some advantages that can help to balance its initial capital and operating costs, e.g.:

- for a given desulphurisation yield, it can reduce the lime consumption (at a given ΔT) or allow the SD operating temperature to increase (at a given Ca/S ratio), thus reducing dust deposition risks
- it helps to achieve a greater ESP efficiency and, therefore, lower final emissions
- it stops erosion of the equipment downstream by the fly ash
- it reduces the volume of waste for disposal
- it collects a saleable product (fly ash); useful as the market for fly ash is well-established.

The pre-collector is normally a simple one-field ESP. However, in retrofits the existing particulate control is often used as a pre-collector.

In the US, ball mill slakers are typically used for lime slaking in spray dry scrubber processes. In Europe, the majority of spray dry scrubber processes are equipped with detention-type tank slakers. The simple tank slaker can be used for pulverised quick lime.

The main part of the absorber is the lime slurry spray nozzle. The spray nozzle can be of the rotary atomiser type or of the dual fluid nozzle type. The first one is installed at the centre of the roof and sprays fine droplets of hydrated lime. The flue-gas stream is split prior to entering the absorber, so that approximately 60 % of the gas enters the absorber through the roof gas disperser and the other 40 % through the central gas disperser. Adjusting the two flows and correct positioning of the gas dispersal vanes helps to control the shape of the cloud of atomised droplets and provides an efficient mixing of the flue-gas and sorbent in a narrow zone around the atomiser. The appropriate size of absorber for treating the flue-gas from boilers of 100 MW_e to 150 MW_e capacity, is usually 14 to 15 m (diameter) x 11 to 12 m (cylindrical height).

The spray nozzles of the slurry atomiser in the spray dry absorber have to conform to high specifications to maintain a constant spraying quality. For example, the nozzles must be able to resist flue-gas corrosion and lime erosion. In addition, they must have a low pressure drop and a minimal risk of clogging. Many types of spray nozzle are used in the slurry atomiser, such as the rotary atomiser and the stationary dual-fluid nozzle.

Sorbent utilisation in spray dry scrubbers is higher than in sorbent injection processes, but unreacted lime amounts for about 10 – 40 % of the make-up lime and is discharged from the system with calcium sulphite/sulphate. The sorbent utilisation is improved by operating a tight control of the sorbent/water ratio in slurry making, decreasing the approach-to-saturation temperature in the absorber and by recirculating parts of the residue back to the absorber.

The most common means of disposal and utilisation of the spray dry scrubber product is in stabilised landfills. As the by-product contains unreacted lime, it is not disposable untreated, because it produces dust and there may be a risk of an uncontrolled leaching of hazardous components. Therefore, it is specially conditioned by mixing with water and fly ash to produce a disposable fixed product.

The residue is both an advantage and disadvantage to the system. Establishing a utilisation for the residue is a key aspect of the application of a spray dry scrubber. As it contains a large amount of unreacted lime, the product is used as a solvent for wet FGDs sited nearby, providing the ash content is low enough. Recent research suggests a new field of application for the residue product is as an additive to fertilisers where sulphur is required.

Spray dry absorbers usually operate at 20 – 30 K above the saturation temperature, where the saturation temperature of flue-gas is between 45 – 55 °C. Thus, most plants do not require a reheating of the clean flue-gas, although the required stack temperature must still be met in some way.

The spray dry scrubber is suitable for low-to-moderate fuelscontaining sulphur and for use in smaller facilities. The equipment includes slurry preparation, handling and atomisation equipment, all of which have to be able to withstand erosion from the slurry. The dry solid by-product can be used in a range of different construction purposes.

The spray dry scrubber process is well established as a commercially available technique. Of the total worldwide capacity equipped with dry FGD, 74 % (18655 MW of electricity in 1998) use spray-drying processes [33, Ciemat, 2000].

The capital cost for the spray-dry system mainly depends on the capacity of the plant and the type and layout of the spray absorber and the injection system. Reported capital costs differ a lot, depending on the type of power plant. The capital cost of a spray-drying system is approximately 30 – 50 % less than the capital cost of a wet limestone process for the same size of LCP, but the operation costs are higher due to higher sorbent costs. As spray drying uses lime, the use of a single-module spray dryer is limited to below 700 MW_{th} units 700000 m^3/h and to low and moderate fuels containingsulphur, in order to keep the operational costs within reasonable limits. Spray dry systems are only cheaper for smaller size units and low operations.

Spray dry scrubber costs for a boiler case have been estimated to be EUR 18 – 25 MW_{el} investment costs, and EUR 0.5 – 0.7 per MWh (heat input) operating and maintenance costs. The cost of the reduced pollutant was EUR 600 – 800 per tonne of sulphur dioxide removed. The effect on the price of electricity was approximately EUR 6 per MWh (electricity produced). Higher peak prices correspond to smaller size LCPs in comparison to wet FGD applications.

A larger diesel engine has an oxygen content of about 13 – 15 vol-% O_2 in the flue-gas (air factor 2.7 – 3.5). A boiler plant typically 3 – 6 vol-% O_2 (air factor 1.2 – 1.4) dependent on the used fuel. A higher oxygen content means a greater exhaust gas flow and need for a greater FGD reactor system, which leads to a higher investment cost, etc.

Depending on the different possibilities for by-product utilisation, the by-product treatment and disposal costs have to be taken into account for the spray dry processes when doing cost comparisons between the different desulphurisation methods.

3.3.5 Sorbent injection

3.3.5.1 Furnace sorbent injection

Furnace sorbent injection involves the direct injection of a dry sorbent into the gas stream of the boiler furnace (Figure 3.15). Typical sorbents include: pulverised limestone ($CaCO_3$) and dolomite ($CaCO_3 \cdot MgCO_3$). In the furnace, the addition of heat results in calcination of the sorbent to produce reactive CaO particles. The surface of these particles reacts with the SO_2 in the flue-gas to form calcium sulphite ($CaSO_3$) and calcium sulphate ($CaSO_4$). These reaction products are then captured along with the fly ash by the particulate control device, typically an ESP or fabric filter. The SO_2 capture process continues into the precipitator, and into the filter cake of the fabric filter. The residues are disposed of, for example, as landfill, although careful control is needed because they include active lime and calcium sulphite. Possible utilisation of these residues is under investigation.

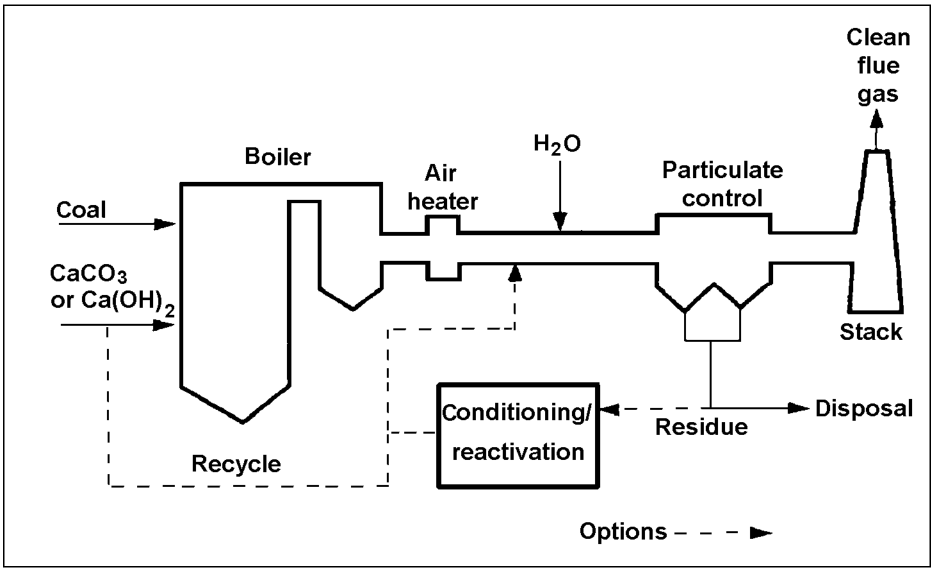


Figure 3.15: Furnace sorbent injection
[33, Ciemat, 2000]

The SO_2 removal reaction occurs in the following two steps as illustrated in Figure 3.16.

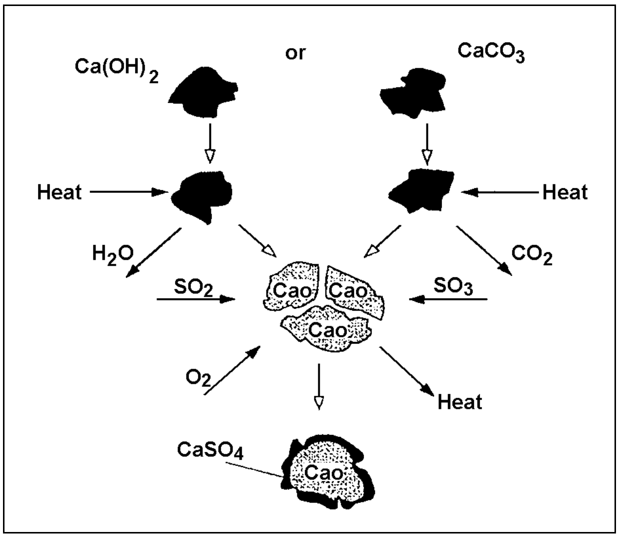


Figure 3.16: SO_2 removal reactions in furnace sorbent injection
[33, Ciemat, 2000]

$$CaCO_3 + heat \rightarrow CaO + CO_2 \quad or \quad Ca(OH)_2 + heat \rightarrow CaO + H_2O$$

$$CaO + SO_2 + ½\ O_2 \rightarrow CaSO_3 + heat$$

Furnace sorbent injection provides the added benefit of removing SO_3.

The critical temperature range for the limestone reaction in furnace sorbent injection is 980 - 1230 °C. Once a reactive lime (CaO) is produced, it must have sufficient time (at least one half-second) in the critical temperature range. Hydrated lime has two reaction windows: 980 – 1230 °C and around 540 °C. This was discovered only recently.

Thermochemically, $CaSO_4$ is not stable at temperatures above 1260 °C in an environment typical of high sulphur fossil fuel-fired combustion products, that is 2000 – 4000 ppm SO_2, for example, for firing coal. The lower temperature limit for the formation of $CaSO_4$ depends on complex interactions between sulphation kinetics, crystal growth and sintering, and the build-up of a barrier layer of $CaSO_4$ on the surface of the reactive CaO.

About 50 % of SO_2 removal efficiency can be achieved at a sorbent molar ratio (Ca/S) of 4 - 5 when limestone is injected into the boiler furnace at near optimum operation. SO_2 removal efficiency and limestone utilisation efficiency are lower than with other FGD systems. There are several measures to improve SO_2 removal efficiency at low capital cost, for instance, by adding some devices to the furnace sorbent injection unit. The simplest measure is to spray water into the duct before the precipitator. This results in an improvement in SO_2 removal efficiency of about 10 %.

Recycling the reaction product is an effective alternative and has been investigated in order to improve efficiencies of both SO_2 reduction and limestone utilisation. The reaction product collected by the particulate control device (ESP or fabric filter) is re-injected into the furnace or duct and circulated several times. In some processes, it is recycled after some conditioning. These measures are expected to achieve 70 – 80 % SO_2 removal efficiency.

Ash handling and disposal are complications in furnace sorbent injection, mostly due to the sheer quantity of the reaction products to be processed. Operating at a Ca/S molar ratio of 2.0 with a 10 % ash coal almost triples the rate at which the ash must be collected by the particulate control device and then transferred to the ash disposal site. Some retrofitted plants require improvements in the ESP to accommodate such amounts.

Although many research projects are in progress to utilise the reaction product, most utilities equipping furnace sorbent injection must have a specially prepared disposal site, in contrast to wet scrubbers which produce a saleable by-product, i.e. gypsum.

The process is suitable for low sulphur containing fuels and for use in small plants. With 'Circulating Fluidised Bed Combustion' (CFBC), this technique operates under optimal temperature conditions, using low temperature combustion in the range of 800 – 950 °C with higher absorption efficiency for a surplus of sorbent above a factor of 2.

The process itself is relatively simple, and therefore requires less operation and maintenance. The process produces a dry solid residue, which needs no further treatment before being discharged to a landfill or being used as a construction material.

Furnace sorbent injection can cause slagging and fouling of heat-exchangers, so sootblowing may have to be increased.

The most recent references relating to this measure are from China, where this process has proven to be suitable due to the moderate SO_2 emission requirements, the local coal sulphur content and the simplicity of the process.

Capital costs for the furnace sorbent injection processes in power generation are lower than for the spray-dry system and the wet scrubber. A 350 MW_{th} unit, for instance, with one reactor has a capital cost of approximately 25 % of the capital cost of a wet limestone process. The cost of the limestone accounts for roughly half of the process operating costs, which overall are low due to the reactant price.
One benefit of this simple process is that no extra staff are needed to operate or maintain the process. A re-use of the by-product is possible, but it has no economic value.

3.3.5.2 Duct sorbent injection (dry FGD)

Duct sorbent injection means injection of a calcium- or sodium-based sorbent into the flue-gas, between the air heater and an existing ESP or fabric filter as shown in Figure 3.17.

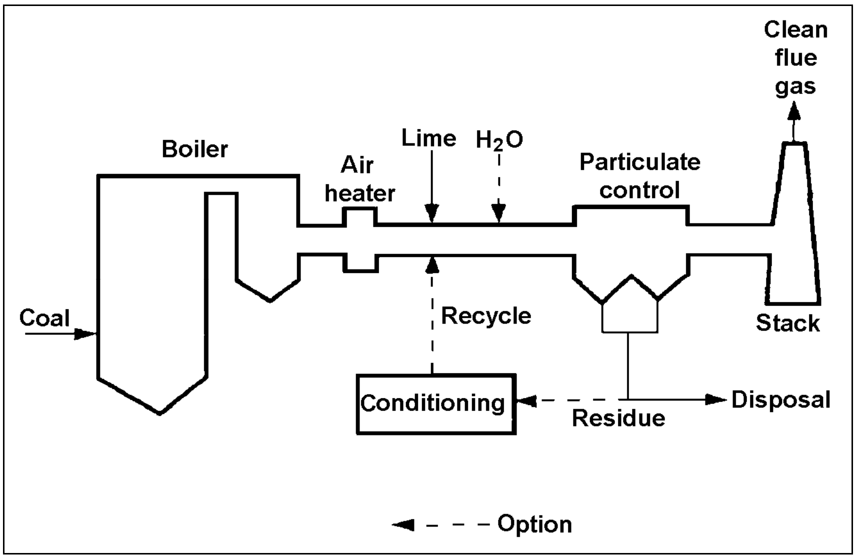


Figure 3.17: Duct sorbent injection
[33, Ciemat, 2000]

The most common types of duct sorbent injection are:

- dry hydrated lime, which requires humidification
- dry sodium injection, which does not require humidification
- lime slurry injection or in-duct scrubbing which does not require a separate humidification step.

The humidification water serves two purposes. First, it activates the sorbent to enhance SO_2 removal and, secondly, it conditions the particulate matter to maintain efficient ESP performance.

Even though duct sorbent injection is an outwardly simple process, several of the key phenomena to increase its control is a) the desulphurisation of flue-gas by calcium- or sodium-based sorbent is the multifold recycling of the product with high amount of unreacted absorbent, and b) the coupling with an existing ESP increase the efficiency by reducing temperature and having higher humidity. The way how the ESP is able to collect up to 100 times more product and fly ash than at a single throughput to a duct injection process is not well understood. An additional parameter is, to humidify the recycled products in a way, that walls and ESP are not in direct contact to water, to avoid corrosion risk.

After injection, the sodium bicarbonate decomposes thermally to form sodium carbonate. After the initial sorbent surface of the sodium carbonate has reacted with SO_2 to form sodium sulphite or sulphate, the reaction slows due to pore pluggage (which resists the gas phase diffusion of SO_2). In order for the reaction to continue, the sorbent particle must decompose further. This decomposition evolves H_2O and CO_2 gases into the surrounding atmosphere, creating a network of void spaces throughout the particle. This process exposes fresh reactive sorbent and allows SO_2, once again, to diffuse into the particle interior. This increase in surface area is in the order of 5 – 20 times the original surface area, depending on the specific sorbent considered. The following series of reactions are thought to take place to produce sodium carbonate for the removal of SO_2:

$$\mathbf{2NaHCO_3 \rightarrow Na_2CO_3 + CO_2 + H_2O}$$

$$\mathbf{Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2}$$

$$\mathbf{Na_2CO_3 + SO_2 + \tfrac{1}{2}\,O_2 \rightarrow Na_2SO_4 + CO_2}$$

The rates of decomposition and subsequent sulphation of the sodium compound particle are a complicated function of gas temperature, rate of heat transfer to the particle, flue-gas H_2O and CO_2, partial pressures, and the effects of other flue-gas components present.

The characteristics of duct sorbent injection technologies are low capital costs, the simplicity of the process, and their adaptability to difficult retrofit situations. However, they have a relatively low SO_2 removal efficiency. This disadvantage and the low sorbent utilisation efficiencies have made commercialisation difficult. However, duct sorbent injection has great potential for relatively old and small boilers, so various duct sorbent injection processes are currently being developed to improve SO_2 removal and reliability. The goal of SO_2 removal efficiencies in duct sorbent injection used to be, generally, at least 50 %. The emerging processes aim to achieve 70 – 95 % SO_2 removal efficiencies without appreciable additional capital costs and operational difficulties, the improvements being based on a better understanding of duct sorbent injection.

Spent sorbent recycling is especially important in the economics of duct sorbent injection because shorter sorbent residence times (0.5 – 3.0 seconds) have led to lower sorbent utilisation compared to conventional spray dry scrubbers. Only 15 to 30 % of $Ca(OH)_2$ by weight usually reacts with SO_2 without spent sorbent recycling. This means that 70 to 85 % of unreacted $Ca(OH)_2$ collected in the ESP is disposed of with the dry fly ash. Low sorbent utilisation is a disadvantage in duct sorbent injection processes. Spent sorbent recycling has recently been adopted in many processes to improve sorbent utilisation and to enhance SO_2 removal performance.

In a sorbent recycling system, a portion of these collected solids can be recycled back to the duct to provide another opportunity for the $Ca(OH)_2$ to react with SO_2. Recycling these solids increases the total $Ca(OH)_2$ content in the system without increasing the rate of fresh lime addition. Therefore, any increase in SO_2 removal is achieved without increasing fresh sorbent costs.

The duct sorbent injection process is very simple and is easy to operate, so there are no major risks of process malfunction.

The process is suitable for various fuels and combustion techniques, especially when the injection is arranged to the cooler part of the duct. It is possible to avoid sorbent sintering and/or melting, when the sorbent is supplied to the colder part of the flue-gas duct.

Because the control of the process is very easy to implement, changes in the boiler load or in other parameters do not affect the efficiency.

Of the worldwide capacity equipped with the dry FGD technology, 23 % (5929 MW of electricity in 1998) use the dry duct injection and sorbent furnace injection processes.

Dry sorbent injection processes are economically competitive at small power plants. The investment costs are low, and this measure is quite easy to build into an existing power plant. Reported capital costs of the duct sorbent injection process vary a lot, depending on the sulphur content of the fuel and on the plant size.

The required reactants are more expensive than in the limestone processes, such as in furnace injection, which means that the operating costs tend to be bigger even though a smaller Ca/S-mole ratio is possible. The reduction rate of the process can be improved by increasing the Ca/S-ratio, which means increased sorbent costs and auxiliary power demand. The by-product cannot always be re-used, which causes more expenses to the operator.

Modified dry FGD process

Hot, untreated flue-gas from a boiler or from after the pre-collector (the pre-collector is not shown on the picture below) when introduced into the dry FGD reactor via a gas disperser, comes into contact with a free flowing, humidified powder of fly ash and lime. Its reactive components are rapidly absorbed into the alkaline components of the powder. Water is simultaneously evaporated to attain the flue-gas temperature required for the efficient collection of SO_2. Control of the gas distribution, the powder flowrate, the distribution and the amount of humidifying water ensures that the appropriate conditions for optimum SO_2 removal efficiency are obtained.

The treated exhaust gas flows to a particulate collector (fabric filter or electrostatic precipitator), where particulates in the flue-gas are removed. Outlet gases from the particulate collector are transported to a stack by means of an induced draft fan. The solids collected are recycled to the dry FGD reactor via a humidifier system. The hopper level controls the blow-down of powder to the by-product silo for disposal [135, Alstom Power, 2002].

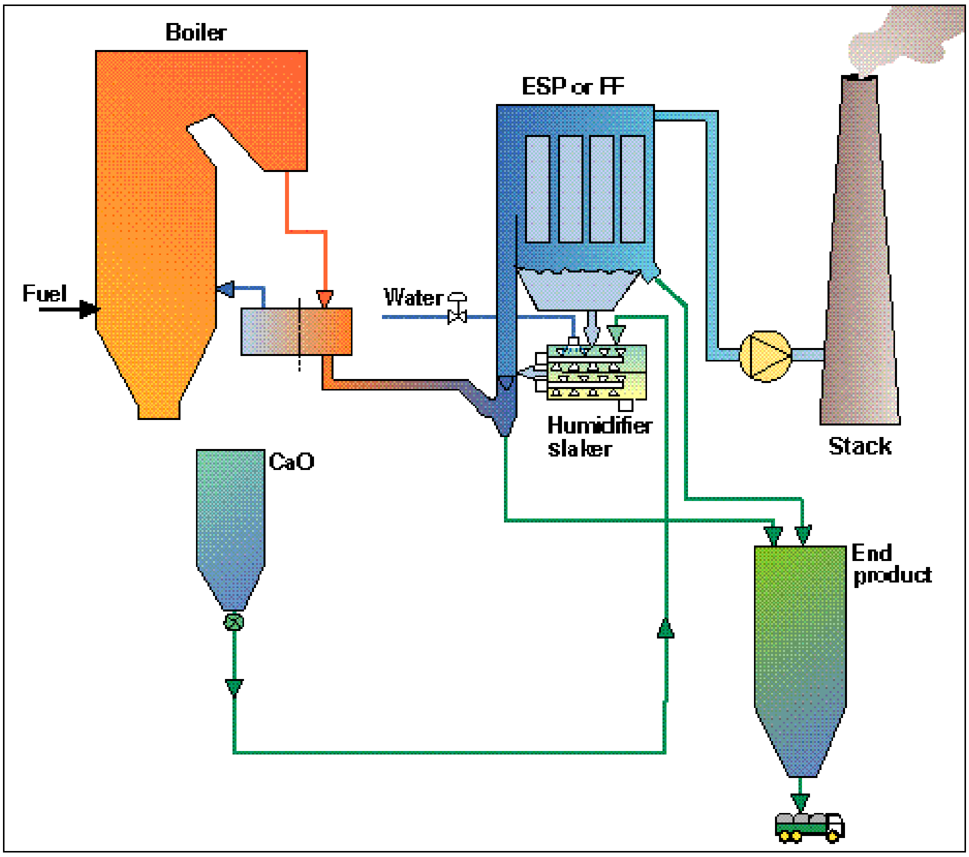


Figure 3.18: Modified dry FGD process
[135, Alstom Power, 2002], [162, Notter, et al., 2002]

Furthermore, the need for sophisticated special equipment is minimised in the modified dry FGD process. There is no rotary atomiser or associated to its high-speed machinery; nor are there any dual fluid nozzles, with their associated need for compressed air. Power requirements for the mixing of the recycle/reagent in the mixers are much lower than for the corresponding items in a conventional dry flue-gas cleaning system: by comparison rotary atomisers and dual fluid nozzles appear much more complex than the mixer. An important consequence of using mixers rather than nozzles or rotary atomisers is that all the equipment that might need the operator's attention is placed near ground level, out of the flue-gas stream and in an enclosure along with the fabric filter. This arrangement leads to lower costs and easier maintenance.

3.3.5.3 Hybrid sorbent injection

Hybrid sorbent injection is a combination of furnace sorbent injection and duct sorbent injection to improve SO_2 removal efficiency. A feature of hybrid sorbent injection is the application of limestone as a sorbent. This is desirable as limestone is cheaper than lime, which is generally used in spray dry scrubbers. Some hybrid sorbent injection processes have reached commercial status because of the following main operational features:

- relatively high SO_2 removal rate
- low capital and operational costs
- easy to retrofit
- easy operation and maintenance with no slurry handling
- reduced installation area due to compact size of equipment
- no waste water treatment needed.

3.3.5.4 Circulating fluid bed (CFB) dry scrubber

The circulating fluid bed (CFB) process is a type of dry scrubber, but separate from either the spray dryer scrubber or sorbent injection. However, it is the only process of its kind in this document and is classified as a CFB dry scrubber under sorbent injection processes.

The CFB process has been in commercial operation on five coal-fired utility boilers in Germany since 1987. Hydrated lime is injected directly into the CFB reactor. Burnt lime can be slaked on site in a separate process.

Flue-gas from the boiler air preheater enters the CFB reactor at the bottom and flows vertically upwards through a venturi section. The venturi is designed to achieve the proper flow distribution throughout the operating range of the vessel. Inside the venturi, the gas is first accelerated, then decelerated before entering the upper cylindrical vessel. The upper height of the vessel is designed to accommodate the mass of bed material required for the desired Ca and SO_2 contact time. All external inputs, such as the recirculating material, fresh reagent and the gas conditioning water are introduced to the gas on the diverging wall of the venturi. The vessel has no internal mechanical or structural components.

The process is not complicated to operate and easier to maintain because it does not require high maintenance mechanical equipment such as grinding mills, abrasion resistant slurry pumps, agitators, rotary atomisers, and sludge dewatering devices. Furthermore, the increased effective surface area of the circulating bed permits successful capture of virtually all of the SO_3 in the gas, eliminating the possibility of gas path corrosion from condensate SO_3 aerosol mist.

3.3.6 Regenerable processes

In regenerable processes, the spent sorbent is re-used after thermal or chemical treatment to produce concentrated SO_2 which is then usually converted to elemental sulphur. The first regenerable processes were put into commercial use in the early 1970s. As these are complex processes requiring high capital costs, as well as more energy to operate, they are not widely used in combustion plants.

Before large-scale FGD application, sulphur used to be an expensive resource, but today it is recovered from several industrial processes and hence its price has dropped, so that now it has very low commercial value. As these processes are mostly only economic with product payback, the low prices for sulphur mean that they are mostly not competitive. Some applications have been converted to other processes. Only LCPs within or neighbouring refineries or chemical plants use these processes when large-scale regeneration is applied at the industrial site.

3.3.6.1 Sodium sulphite bisulphite process

The sodium sulphite bisulphite process is the most widely used regenerable process. Commercial plants using this process are operated for industrial boilers and power stations burning hard coal, lignite, oil, and petroleum coke. The total number of plants amounts to 38 (altogether about 23 million m^3/h of fuel gas), including six coal-fired boilers. The majority of these plants are located in Germany, Japan, and the US. Nevertheless, LCP operators in many cases have already changed techniques or are changing for economic reasons to cheaper FGD processes.

The process is based on a sodium sulphite/bisulphite equilibrium. The flue-gas first passes to the pre-scrubber unit which saturates and cools the gas as well as removing halides and some of the remaining particulate. A variety of pre-scrubber systems can be used but each includes a recirculating water stream to ensure good contact plus a purge stream to control the chloride and solids concentration. The following reaction takes place in the absorber:

$$\mathbf{Na_2SO_3\,(aq) + SO_2(g) + H_2O(l) \rightarrow 2NaHSO_3\,(aq)}$$

Absorption is countercurrent and as the liquor travels down the column more sulphite is converted to bisulphite until it leaves the column. The small quantity of fly ash passing through the pre-scrubber is also captured in the solution and is removed by filtration before the clean liquor is passed to an intermediate storage area prior to regeneration.

In the regeneration area, the major reaction is:

$$\mathbf{2NaHSO_3\,(aq) \rightarrow Na_2SO_3\,(aq) + SO_2\,(g) + H_2O)\,(g)}$$

Absorber product liquor is regenerated in forced circulation evaporators. The sodium sulphite subsequently crystallises out of solution and is re-dissolved in condensate to produce the absorber feed liquor.

Two side reactions occur in the process, one in the absorption area and the other during regeneration. In the absorption area, a small quantity of sodium sulphate which lowers the liquor capacity for SO_2 absorption is produced due to the oxygen content in the flue-gas:

$$\mathbf{2Na_2SO_3\,(aq) + O_2\,(g) \rightarrow 2Na_2SO_4\,(aq)}$$

During regeneration, a small quantity of sodium thiosulphate is formed by a disproportionation reaction:

$$\mathbf{2Na_2SO_3\,(aq) + 2NaHSO_3\,(aq) \rightarrow 2Na_2SO_4\,(aq) + Na_2S_2O_3\,(aq) + H_2O\,(l)}$$

This reaction is autocatalytic so the thiosulphate concentration is maintained at a low level by purging. Sodium hydroxide is added as make-up to replace any sodium lost – mainly through the oxidation of sodium sulphite to sulphate in the absorber. Ethylenediamine tetraacetic acid (EDTA) is also added to inhibit the oxidation.

This process has been operated in Germany since 1987 for desulphurisation of the flue-gas from two adajacent power plants with 350 MW_e and 325 MW_e output. The combined plant has produced 80000 – 90000 t/yr of high quality sulphur and 15000 – 20000 t/yr of pure sodium sulphate. The sodium sulphite bisulphite process has a complex design and requires qualified operating staff.

3.3.6.2 Magnesium oxide process

The magnesium oxide process is a regenerable wet scrubbing process, which uses magnesium hydroxide solution as sorbent. It is essentially the same as for the limestone wet scrubber except for the regeneration step for the spent sorbent. HCl and HF in the flue-gas are removed in a pre-scrubber, to avoid contamination of the magnesium salt after SO_2 absorption. The flue-gas then enters the scrubber where the SO_2 is absorbed by aqueous slurry of magnesium sulphate, formed from the magnesium hydroxide sorbent:

$$\mathbf{MgSO_3 + SO_2 + H_2O \rightarrow Mg(HSO_3)_2}$$

$$\mathbf{Mg(HSO_3)_2 + Mg(OH)_2 \rightarrow 2MgSO_3 + 2H_2O}$$

$$\mathbf{2MgSO_3 + O_2 \rightarrow 2MgSO_4}$$

The reaction product, magnesium sulphite/sulphate, is bled continuously from the absorber and dried in a dryer. The magnesium sulphite/sulphate is calcined at about 900 °C in the presence of carbon to regenerate magnesium oxide which is returned to the absorption system:

$$\mathbf{MgSO_3 \rightarrow MgO + SO_2}$$

$$\mathbf{MgSO_4 + C \rightarrow MgO + SO_2 + CO}$$

As a by-product, elemental sulphur, sulphuric acid or concentrated sulphur dioxide is obtained in the process. These are saleable by-products, which can be sold to reduce overall operating costs. Otherwise, regeneration of the magnesium oxide would require a large amount of thermal energy.

Three coal-fired plants with the magnesium oxide process currently operate in the US with a total capacity of about 900 MW_e. They were all retrofitted in 1982 to the existing plants and all fire coal with over 3.5 % sulphur. No magnesium oxide plants are currently under construction, and no further plants are known to be planned.

3.3.7 General performance of flue-gas desulphurisation (FGD) techniques

Technique	General SO_2 reduction rate	Other performance parameters		Remarks
		Parameter	Value	
Wet lime/ limestone scrubber	92 – 98 % (depending on the absorber type)	Operating temperature	45 – 60 ºC	• the SO_2 reduction rate for some existing FGD units starts with 85 % • of the total installed FGD capacity, 80 % are wet scrubbers of which 72 % use limestone as the reagent, 16 % use lime and 12 % use other reagents • the selection of limestone (high calcium carbonate content, low Al, F and Cl content) is an important issue to assure a good SO_2 removal rate • the distance for bringing the limestone to the plant and the reactivity of the limestone are also two important questions to take into account • sometimes organic buffers are used to maintain the pH value of the scrubbing solution • the energy loss due to the reheating of the flue-gas is large compared to dry FGD systems and combined SO_2/NO_X removal systems, which do not generally require flue-gas reheating • the problem associated with the rotating gas-gas heat-exchanger operating at about 150 ºC is inherent internal flue-gas leakage, with from 1 – 3 % of the raw flue-gas going directly to the stack without reducing the SO_2 content • several plants use wet FGD systems with cooling tower or wet stack discharge. The cooling tower or wet stack discharge of cleaned flue-gas eliminate the need for costly reheating, save the reheating energy and result in significantly lower ground level concentrations of emissions • the production of waste water is a disadvantage of the wet limestone scrubber • high water consumption • loss in the overall plant efficiency because of the high energy consumption (in average, a suspension pump consumes about 1 MW) • gypsum as a saleable by-product.
		Sorbent	Limestone lime	
		Energy consumption as % of electrical capacity	1 – 3 %	
		Pressure drop	20 – 30 (10^2 Pa)	
		Ca/S molar ratio	1.02 – 1.1	
		Reliability	95 – 99 % (of operating time)	
		Residue/by-product	Gypsum	
		Gypsum purity	90 – 95 %	
		Residence time	10 sec	
		Lifetime of rubber lining	>10 years (hard coal)	
		SO_3 removal rate	92 – 98 %	
		HCl removal rate	90 – 99 %	
		HF removal rate	90 – 99 % in the absorber	
		Particulate	>50 % depending on the particle size	

Table 3.5: General performance of the wet lime/limestone scrubber for reducing sulphur oxide emissions

Technique	General SO_2 reduction rate	Other performance parameters		Remarks
		Parameter	Value	
Seawater scrubbing	85 – 98 %	Operating temperature (example)	145 ºC (example of flue-gas inlet) 30 – 40 °C (= seawater outlet temp.)	• seawater must be available • only a few units are in operation at power plants • by applying a seawater scrubbing process to a combustion plant, the local conditions such as seawater conditions, tidal flows, the marine (aquatic) environment close to the scrubber water outlet, etc. needs to be carefully examined in order to avoid negative environmental and ecological effects. Effects may arise from the reduction of the pH level in the general vicinity of the power plant as well as from the input of remaining metals (heavy metals sometimes called trace elements) and fly ash. This is especially applicable to plants situated in an estuary • the applicability of the seawater scrubbing is very high as the process is simple and does not require slurry handling • the operating cost are low compared with a wet FGD system • the flue-gas first needs to be dedusted • applicable only for low sulphur fuel.
		Sorbent	Seawater/air	
		Residence time of seawater in aerator	15 min. (example, residence time depends on type of process)	
		Max. flue-gas flow per absorber	no limitation in gas flow	
		Reliability	98 – 99 %	
		Residue/by-product	None	
		Energy consumption as % of electric capacity	0.8 – 1.6 %	
		HCl removal rate	95 – 99 %	
		HF removal rate	95 – 99 % in the absorber	
		Water consumption (example)	15000 m^3/h (depending on bicarbonate concentration in the seawater)	
		Waste water	None (but sulphate ions dissolved in seawater)	
		Pressure drop	10 – 20 (10^2 Pa)	

Table 3.6: General performance of seawater scrubbing for reducing sulphur oxide emissions

Technique	General SO_2 reduction rate	Other performance parameters		Remarks
		Parameter	Value	
Spray dry scrubber	85 – 92 %	Operating temperature	120 – 200 ºC (flue-gas inlet) 65 – 80 ºC (flue-gas outlet)	• it should be noted that SO_3 is removed more effectively in spray dry scrubbers than in wet scrubbers • use of tower mills for slaking can increase the reactivity of the slaked lime • as spray dry scrubbers can remove more SO_3 than wet scrubbers, there is likely to be less of a problem of H_2SO_4 in the environment close to the plant than with wet scrubbers • as power consumption in NO_X and particulate control devices usually amount to less than 0.1 %, the overall power consumption for pollution control is usually below 1.0 % in a plant adopting the spray dry scrubber. This is a great advantage compared with wet scrubbers which require a power consumption of 1.0 – 1.5 % • the four to five times higher cost of the lime sorbent used in spray dry scrubbers in relation to limestone for the dominant wet scrubbers is probably the greatest disadvantage of spray dry scrubbers • investigation showed that about 35 – 85 % of the mercury present in the gas phase upstream of the scrubber is removed • spray dry absorption processes are currently operated at hard coal-fired combustion units. However, the process has proved to be applicable to other fossil fuels such as oil, lignite or peat in pilot studies • with sulphur contents exceeding 3 %, the removal efficiency decreases slightly • the spray dry scrubber efficiency very much depends on the dedusting device used (e.g. fabric filter or ESP), because desulphurisation occurs to a certain extent, for instance, in the filter-cake of the fabric filter • $CaSO_4$ as a residue.
		Sorbent	Lime, calcium oxide	
		Residence time	2 – 10 sec	
		Ca/S molar ratio	1.3 – 2.0	
		Max. flue-gas flow per absorber	700000 m^3/h	
		Removal range of SO_3 and HCl	95 %	
		Recirculation rate of used sorbent	0 – 15%	
		Solid content in injected liquid	10 – 35 %	
		Reliability	95 – 99 %	
		Residue/by-product	Mixture of fly ash, unreacted additive and $CaSO_3$	
		Energy consumption as % of electric capacity	0.5 – 1 %	
		Water consumption	20 – 40 l/1000 m^3 flue-gas (depends on gas temp.)	
		Waste water	None	
		Pressure drop of the spray dryer without the dedusting device	30 (10^2 Pa)	

Table 3.7: General performance of the spray dry scrubber for reducing sulphur oxide emissions

Technique	General SO_2 reduction rate	Other performance parameters		Remarks
		Parameter	**Value**	
Furnace sorbent injection	30 – 50 % 70 – 80 % by recycling the reaction product	Operating temperature	950 – 1150 °C (upper furnace) 540 °C (economiser)	• the efficiency of SO_2 control is primarily a function of the Ca/S molar ratio, the sorbent type, the degree of humidification, the additives available, the injection point and the boiler load • to increase the SO_2 removal efficiency, water can be sprayed into the duct before the precipitator. This results in an improvement of the SO_2 removal efficiency of about 10 % • problem of fouling, slagging and flame stability in the boiler • furnace sorbent injection can increase the amount of unburned carbon-in-ash.
		Sorbent	Limestone, hydrated lime, dolomite	
		Reliability	99.9 %	
		Boiler efficiency drop	2 %	
		Energy consumption as % of electric capacity	0.01 – 0.2 %	
		Residue	Ca salt mixture	
Duct sorbent injection (dry FGD)	50 – 80 %	Operating temperature		• low capital costs and extremely simple installation • easy to retrofit (small space and short construction period) • no waste water • ash handling is more difficult because the ash is enriched with non-reacted lime, which causes the ash to harden after wetting • the tendency for duct wall deposits is increased.
		Sorbent	Limestone, hydrated lime, dolomite	
		Reliability	99.9 %	
		Energy consumption as % of electric capacity	0.2 %	
		Residue	Ca salt mixture	
Hybrid sorbent injection	50 – 80 % (90 % by reactivation of the unreacted CaO by humidification)	Residence time	3 sec	• used in some plant in the US.
CFB dry scrubber	90 – 99 %	Operating temperature	70 – 80 °C	• the CFB vessel is designed with an internal gas velocity range of 1.8 m/s to 6 m/s for boiler loads from 30 to 100 % by clean gas recyrculation • has only been applied a few times • high removal of heavy metals.
		Residence time	3 sec	
		Ca/S	1.1/1.5	
		Recirculation rate of used sorbent	10 – 100	
		Energy consumption	0.3 – 1 %	
		Sorbent	$Ca(OH)_2$	
		Reliability	98 – 99.5 %	
		Pressure drop without dedusting	7 – 15 hPa	
		Residue	$CaSO_3/CaSO_4$/fly ash	

Table 3.8: General performance of different sorbent injection techniques for reducing sulphur oxide emissions

Technique	General SO_2 reduction rate	Other performance parameters		Remarks
		Parameter	Value	
Sodium sulphite bisulphite process	95 – 98 %	Flue-gas temperature in the absorber	45 – 70 ºC	• the sodium sulphite bisulphite process is actually not applied anymore in Europe for coal fired units • as the process uses a solution to absorb SO_2, high efficiency contacting devices such as valve trays or packed beds can be used without scaling problems • in some cases, for example, where a power station is near, or in, a city centre, transport of a large amount of materials (limestone and gypsum) into and out of the power station may well create a nuisance due to noise and traffic movements. In contrast, for the sodium sulphite bisulphite process, there are less traffic movements for caustic soda and sulphur • the sodium sulphite bisulphite process requires high capital costs, and a high demand both in number and qualification of the operating staff and a high power consumption.
		Max S content in the fuel	3.5 %	
		Max flue-gas flow	600000 m^3/h	
		Solid content in injected liquid	20 – 50 %	
		Energy consumption as % of electric capacity	3 – 5.8 %	
		Water consumption	70 – 200 m^3/h (only pre-scrubber)	
		Reliability	>95 %	
Magnesim oxide process	n.a.	Energy consumption as % of electric capacity	n.a.	
		By-product	elemental sulphur, sulphuric acid or concentrated sulphur oxide	
		Reliability	n.a.	
Notes: n.a. = not available				

Table 3.9: General performance of regenerative techniques for reducing sulphur oxide emissions

3.4 Techniques to reduce nitrogen oxide emissions

This section provides generic descriptions of the measures and techniques that are generally used to reduce emissions of nitrogen oxides from combustion installations[3]. Techniques to reduce nitrogen oxides are divided into primary and secondary measures. Primary measures have been developed to control NO_X formation and/or reduction in the boiler, whereas secondary measures are end-of-pipe techniques to reduce NO_X emissions.

Many books, reports and other documents have been published about the reduction of air emission from stationary sources, i.e. LCPs. More detailed information on techniques to reduce nitrogen oxides can be found in [32, Rentz, et al., 1999] and [33, Ciemat, 2000] both of which have been used as technical background material for this part of the BREF.

Nitrogen oxides (NO_X) formed during the combustion of fossil fuels are mainly NO, NO_2 and N_2O. NO contributes to over 90 % of the total NO_X in most combustion types. As already mentioned in Chapter 1, there are, in theory, three different formation mechanisms for NO_X: thermal NO formation; prompt NO; and the formation of NO from nitrogen as a component of the fuel. A number of primary measures are currently used in LCPs in order to minimise the formation of NO_X by these mechanisms.

With data collected by EURELECTRIC, VDEW and VGB up to 1996, an overview of denitrification is presented in Table 3.3 with estimates for the further application up to the end of 1999.

Plants and technique	**Number of sites and electrical power**		**Plants with DENOX and controlled electrical power**	
Country	**No of sites**	**MW_e**	**No of sites**	**Electrical power (MW_e)**
Austria	18	4852	17	4178
Belgium	31	5867	-	-
Denmark	13	8447	4	1754
Germany	960 (N2)	91090	166	35249
Greece	10	6138	-	-
Finland	30	5054	2	600
France	17	18218	6	1850
Ireland	10	2955	-	-
Italy	79	41873	27	15690
Luxembourg	-	-	-	-
Netherlands	15	9632	2	1270
Portugal	6	4514	-	-
Spain	41	19357	-	-
Sweden	41	5303	25	2534
United Kingdom	26	37718	-	-
EU-15 (1996)	1297	261018	250	63325
Notes: **N1** including fluidised bed combustion **N2** including German industrial power plants >50 MW_{th})				

Table 3.10: DENOX (secondary measures not including primary measures) at large combustion plants in EU-15
[58, Eurelectric, 2001]

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[3] This chapter mainly addresses techniques for NO_x reduction in boilers. Techniques that are specific for the reduction of NOx emissions from gas turbines and reciprocating engines are described in the fuel specific chapters (liquid fuels, gaseous fuels).

3.4.1 Primary measures to reduce NO_x emissions

There is a wide variety of primary emission reduction measures (combustion modifications) to suppress nitrogen oxides formation in combustion installations. All these measures aim to modify operational or design parameters of combustion installations in such a way that the formation of nitrogen oxides is reduced or so that nitrogen oxides already formed are converted inside the boiler prior to their release. Figure 3.19 summarises the primary measures.

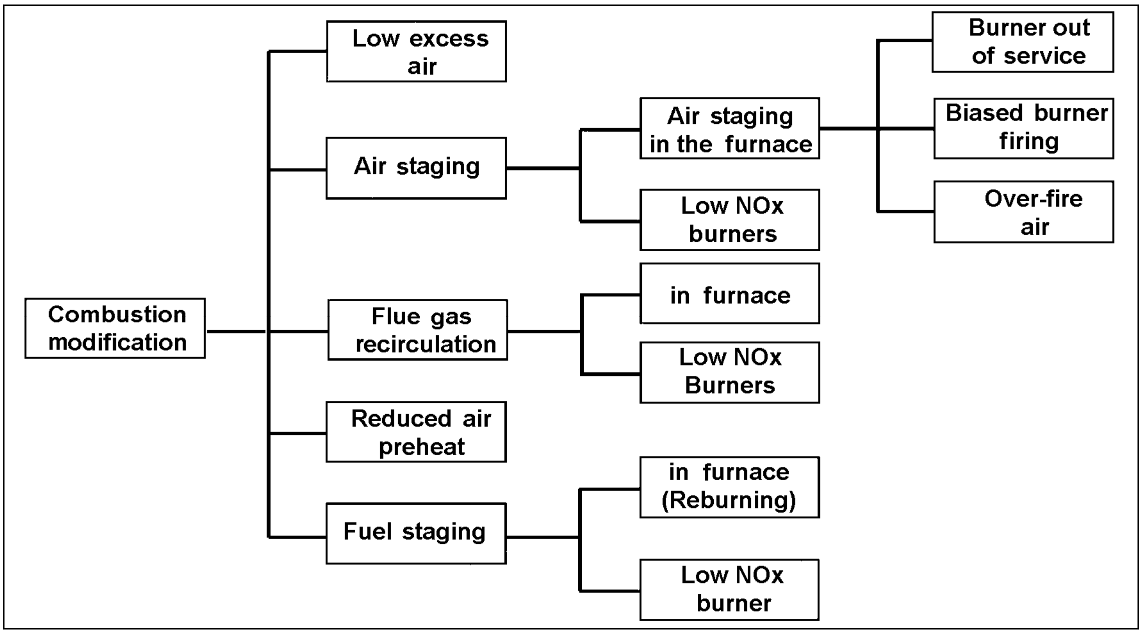

Figure 3.19: Overview of primary measures for reducing nitrogen oxide emissions
[32, Rentz, et al., 1999]

When primary measures (combustion modifications) are introduced, it is important to avoid adverse impacts on boiler operation and the formation of other pollutants. So the following criteria for low NO_X operationS should be taken into account:

- operational safety (e.g. stable ignition over the load range)
- operational reliability (to prevent, e.g. corrosion, erosion, fouling, slagging, overheating of tubes, etc.)
- ability to burn a wide range of fuels
- complete combustion (to reduce the carbon-in-ash levels, as less than 5 % unburned carbon in fly ash is a usual condition for making fly ash saleable to the cement industry. Complete combustion is also desired in order to avoid high emissions of carbon monoxide)
- lowest possible pollutant emissions, i.e. avoiding formation of other pollutants, for example particulate organic matter (POM), or N_2O
- minimal adverse impact on the flue-gas cleaning equipment
- low maintenance costs.

3.4.1.1 Low excess air

Low excess air is a comparatively simple and easy-to-implement operational measure for the reduction of nitrogen oxides emissions. By reducing the amount of oxygen available in the combustion zone to the minimum amount needed for complete combustion, fuel bound nitrogen conversion and to a less extent thermal NO_X formation are reduced. A considerable emission reduction can be achieved with this measure especially in the case of old power plants, therefore it has been incorporated in many existing large combustion installations. In general, new plants are equipped with extensive measuring and control equipment that enables optimum adjustment of the combustion air supply.

No additional energy is required for low excess air firing and, if operated properly, no reduction in the availability of the power plant should result from this primary emission reduction measure. However, as the oxygen level is reduced, combustion may become incomplete and the amount of unburned carbon in the ash may increase. In addition, the steam temperature may decrease. Reducing the oxygen in the primary zones to very low amounts can also lead to high levels of carbon monoxide. The result of these changes can be a reduction in the boiler efficiency, slagging, corrosion and a counteractive overall impact on boiler performance. Another effect of this technique is that not only will NO_X be reduced, but also SO_3, which can cause corrosion and fouling on the air preheater and the particulate control device. Potential safety problems, which might result from the use of this technique without a strict control system, include fires in air preheaters and ash hoppers, as well as increases in opacity and in the rates of water-wall wastage.

3.4.1.2 Air staging

NO_X reduction by air staging is based on the creation of two divided combustion zones, a primary combustion zone with a lack of oxygen and a secondary combustion zone with excess oxygen in order to ensure complete burn-out. Air staging reduces the amount of available oxygen (in 70 – 90 % of the primary air) in the primary combustion zone. The sub-stoichiometric conditions in the primary zone suppress the conversion of fuel-bound nitrogen to NO_X. Also the formation of thermal NO_X is reduced to some extent by the resulting lower peak temperature. In the secondary zone, 10 – 30 % of the combustion air is injected above the combustion zone. Combustion is completed at this increased flame volume. Hence the relatively low-temperature secondary stage limits the production of thermal NO_X.

In boilers and furnaces, the following options exist for achieving air staging:

- **biased burner firing (BBF):** Biased burner firing is frequently used as a retrofit measure at existing installations (only for vertical boilers), as it does not require a major alteration of the combustion installation. The lower burners operate fuel-rich whereas upper burners are supplied with excess air
- **burners out of service (BOOS):** Since putting some burners out of service does not require a major alteration of the combustion installation, this measure is frequently used as a retrofit measure at existing vertical boilers. Here, the lower burners are operated under fuel-rich conditions, whereas the upper burners are not in use, injecting only air. The effect of this measure is similar to overfire air, but NO_X emission reduction by BOOS is not that efficient. Problems may arise with maintaining the fuel input, because the same amount of thermal energy has to be supplied to the furnace with fewer operating burners. Therefore, this measure is generally restricted to gas- or oil-fired combustion processes
- **overfire air (OFA):** For overfire air operation, air ports (windboxes) are installed in addition to the existing burners. A part of the combustion air is injected through these separate ports, which are located above the top row of burners. Burners can then be operated with low excess air, which inhibits NO_X formation, the overfire air ensuring complete burn-out. Typically 15 – 30 % of the total combustion air that would normally pass through the burners is diverted to overfire air ports. Retrofitting overfire air to an existing boiler involves applying water-wall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the windbox.

Air staging in the furnace does not increase the energy consumption of the combustion plant and does not have any adverse effects on its operational availability if properly applied.

There are two major drawbacks of air staging as a NO_X removal technique. The first one is the usually significant amount of CO that may be formed if the air nozzles are not well situated. Another effect is that the amount of unburned carbon may increase in the case of retrofit, due to a volume decrease between the end of the combustion zone and the first heat-exchanger.

This is a very inexpensive way of decreasing nitrogen oxide emissions. It is very often applied with other primary measures such as low NO_X burners, so it is quite difficult to estimate the cost effects of the air staging element alone. A rough estimate is that OFA costs are almost EUR 1 million for a boiler with 250 $MW_{th,}$ and the price per reduced tonne of NO_X is typically EUR 300 – 1000 [32, Rentz, et al., 1999].

3.4.1.3 Flue-gas recirculation

The recirculation of flue-gas results in a reduction of available oxygen in the combustion zone and, since it directly cools the flame, in a decrease of the flame temperature: therefore, both fuel-bound nitrogen conversion and thermal NO_X formation are reduced. The recirculation of flue-gas into the combustion air has proven to be a successful method for NO_X abatement in high temperature combustion systems, such as wet bottom boilers and oil- or gas-fired installations. Figure 3.20 is a schematic of this technique.

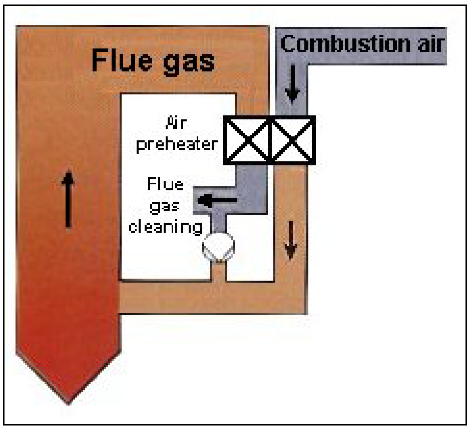

Figure 3.20: Flue-gas recirculation
[34, Verbund, 1996]

As can be seen by the figure above, part of the flue-gas (20 – 30 % at temperatures of about 350 – 400 °C) is withdrawn from the main flue-gas flow downstream of the air preheater, usually after any particulates have been removed, and then recycled to the boiler. The recirculated flue-gas can be mixed with combustion air in the burner or with staging air. Special burners designed to operate on recirculated flue-gas are required. If there is an excessive amount of recirculated flue-gas, this can lead to some operational limitations, e.g. corrosion problems when burning a fuel containing sulphur, efficiency losses due to a temperature increase at the stack, increased energy consumption for the ventilators. Therefore, operators usually aim to limit the amount of recirculated flue-gas (approximately 30 %) and compensate for the higher NO_X emissions by using advanced low NO_X burners.

3.4.1.4 Reduced air preheat

The combustion air preheat temperature has a significant impact on NO_X formation mainly for gas and oil firing systems. For these fuels, the main part of NO_X is determined by thermal NO mechanism, which depends on the combustion temperature. Reduction of the air preheat temperature results in lower flame temperatures (peak temperatures) in the combustion zone. Accordingly, a higher formation of thermal NO_X is caused. There are two major drawbacks of this technology. Firstly, in several boilers, e.g. in coal burning, high combustion temperatures are required and accordingly high air preheat temperatures are essential for the proper functioning of the combustion installation. Secondly, lowering the air preheat temperature results in a higher fuel consumption, since a higher portion of the thermal energy contained in the flue-gas cannot be utilised and ends up leaving the plant via the stack. This can be counterbalanced by utilising certain energy conservation methods, such as increasing the size of the economiser.

3.4.1.5 Fuel staging (reburning)

Fuel staging, also termed reburning, is based on the creation of different zones in the furnace by staged injection of fuel and air. The aim is to reduce back to nitrogen the nitrogen oxides that have already been formed. As can be seen from Figure 3.21, the combustion can be divided into three zones.

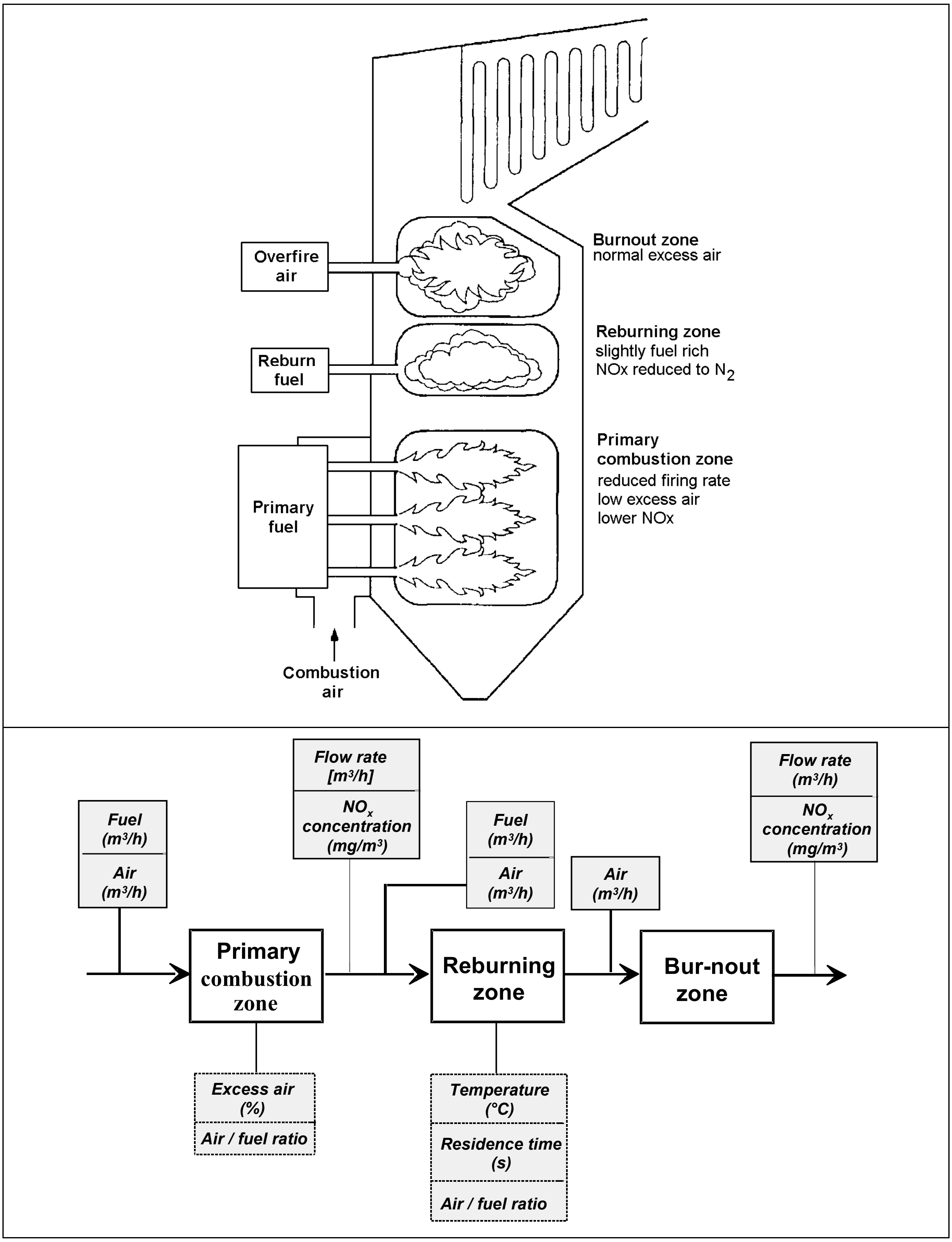

Figure 3.21: The three combustion zones and the relevant parameters in a reburning process [32, Rentz, et al., 1999], [33, Ciemat, 2000]

Reburning involves combustion occurring in three zones:

- in the primary combustion zone (which may be equipped with primary measures), 80 to 85 % of the fuel is burned in an oxidising or slightly reducing atmosphere. This primary burnout zone is necessary in order to avoid the transfer of excess oxygen in the reburning zone, which would otherwise support possible NO_X formation
- in the second combustion zone (often called the reburning zone), secondary or reburning fuel is injected in a reducing atmosphere. Hydrocarbon radicals are produced, reacting with the nitrogen oxides already formed in the primary zone; other unwanted volatile nitrogen compounds like ammonia are generated as well
- in the third zone, the combustion is finally completed through the addition of final air into the burnout zone.

Different fuels can serve as reburning fuel (pulverised coal, fuel oil, natural gas, etc.), but natural gas is generally used due to its inherent properties. Figure 3.22 shows the advantage of natural gas-over-coal and oil. When using coal or oil, nitrogen is present in the reburning fuel in a certain quantity, leading inevitably to NO_X formation in the burnout zone. This drawback is avoided by using natural gas.

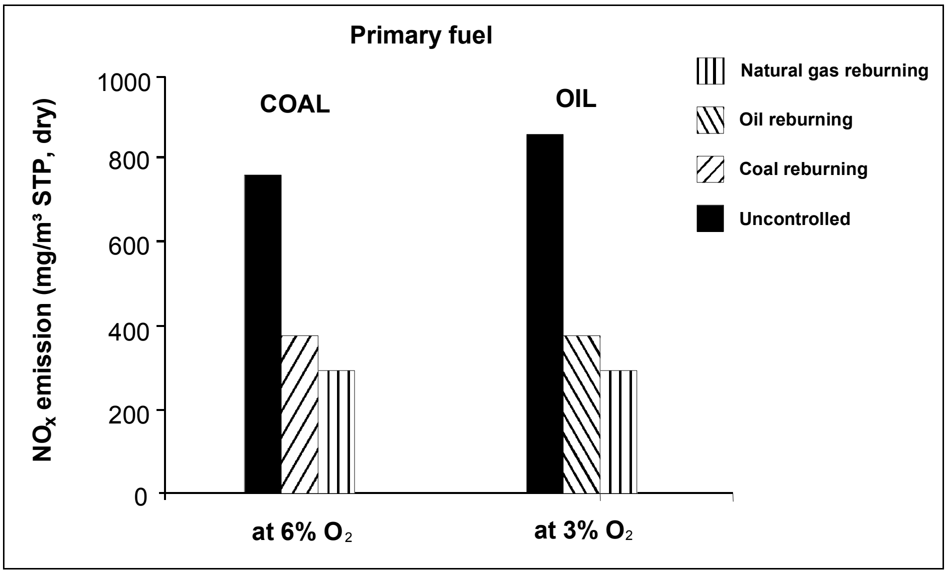

Figure 3.22: Comparison between coal, oil and natural gas as reburning fuel [32, Rentz, et al., 1999]

The efficiency rate of reburning depends on several parameters, including:

- temperature: to obtain low NO_X values, the temperature in the reburning zone should be as high as possible (1200 °C). Figure 3.23 gives the denitrification rate as a function of the reburning rate at different temperatures
- residence time: increasing the residence time in the reburning zone favours NO_X reduction. An appropriate time is between 0.4 and 1.5 s
- aeration rate in the reburning zone: the stoichiometry should be in the range $\lambda = 0.7 - 0.9$
- fuel type
- quality of the mixture between the additional fuel and the flue-gas generated by the primary combustion zone
- excess air in the primary combustion zone: the stoichiometry is approximately $\lambda = 1.1$.

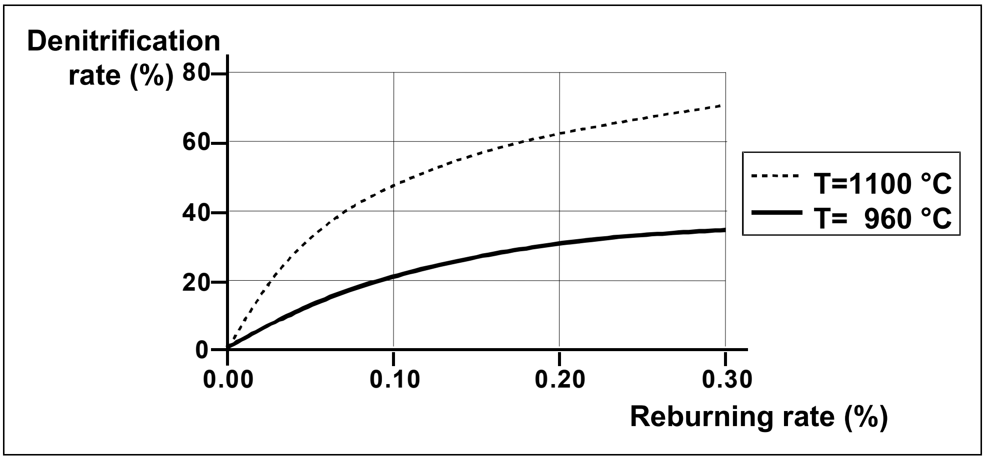

Figure 3.23: Denitrification rate as a function of the reburning rate
[32, Rentz, et al., 1999]

In principle, the reburning technique can be implemented on all types of fossil fuel-fired boilers and in combination with low NO_X combustion techniques (for the primary fuel). This abatement technique, very attractive for new boilers, necessitates large chamber volumes if high amounts of unburned carbon are to be avoided. Therefore, reburning proves to be less appropriate for retrofit situations due to space constraints that may exist in already built installations. Reburning has been installed at large power plants in the US, Japan, the Netherlands, Germany, Italy and the UK. In Italy, reburning (with oil as a reducing agent) has been implemented successfully in many large oil-fired units.

As mentioned earlier, major problems are caused by incomplete combustion. This measure best suits boilers that have a long enough residence time and where proper reburning of fuel is available at a reasonable price. Natural gas has proven to be the best reburning fuel, mostly because it is easily flammable and has neither particles nor sulphur in it.

The costs of reburning depend on the structure of the boiler and on the fuel used. The use of auxiliary fuel, such as natural gas, also incurs costs, but on the other hand, it releases heat to the process and can, therefore, be considered as a usable fuel. So the calculations should be made for the whole power plant economy including possible changes, e.g. in the boiler efficiency.

Experience shows that reburning is not as cost-effective as low NO_X burners with OFA, but it is still an appropriate measure for reducing NO_X emissions. One estimate gives reburning costs as close to EUR 2.5 million for a 250 MW_{th} boiler. There have also been calculations showing that the operating costs of reburning installations are twice as high as the costs for low NO_X burners with OFA.

3.4.1.6 Low NO_x burner

Low NO_X burners have reached a mature stage of development, but further improvements involve an ongoing process and a considerable amount of research work is still devoted to the enhancement of existing low NO_X burner systems. Since design details of low NO_X burners differ significantly from manufacturer to manufacturer, only the general principle is referred to here.

In a classical combustion installation, the combined fuel and air/oxygen mix is entirely injected at the same place. The resulting flame is then composed of a hot and oxidising primary zone located at the flame root and a colder secondary zone located at the flame end. The primary zone generates most of the NO, which increases exponentially with temperature, whereas the contribution of the secondary zone is rather modest.

Low-NO_X burners (LNB) modify the means of introducing air and fuel to delay the mixing, reduce the availability of oxygen, and reduce the peak flame temperature. LNBs retard the conversion of fuel-bound nitrogen to NO_X and the formation of thermal NO_X, while maintaining high combustion efficiency. The pressure drop in air ducts increases, causing more operational expenses. Coal pulverisation, for instance, must usually be improved, and that may lead to higher operating and maintenance costs. There could also be some corrosion problems, especially if the process is not properly controlled.

The low NO_X burning technique requires, at least, the burners to be changed and installation of overfire air (OFA). If the existing burners are classical burners, then changing the burners can almost always be done very cost-effectively. If the burners are delayed combustion low NO_X burners (old type), the benefits of their retrofitting into rapid injection low NO_X burners can be assessed only on a case-by-case basis.

Low NO_X burners with OFA for a 250 MW_{th} cost approximately EUR 1.7 million for a solid fuel boiler. In coal-fired boilers, the price of NO_X reduced is around EUR 500 per tonne of NO_X removed.

According to the different principles to reduce the formation of NO_X, low NO_X burners have been developed as air-staged, flue-gas recirculation and fuel-staged burners.

3.4.1.6.1 Air-staged low NOX burner

In the air-staging process, the primary air is mixed with the total quantity of fuel, producing a fuel-rich flame, which is both relatively cool and deficient in oxygen; conditions in which the formation of nitrogen oxides is inhibited. The fuel-air mixture and the 'secondary air' as shown in Figure 3.24 create an under-stoichiometric combustion zone (primary flame). An internal recirculation zone is created due to the swirl of the 'secondary air' and the conical opening of the burner, which heats up the fuel rapidly. The swirl of the secondary flame is necessary for flame stability. The volatile compounds are freed in the primary flame together with a major part of the nitrogen compounds. Due to the oxygen atmosphere and a high concentration of CO, the oxidation of the nitrogen compounds to NO is limited. Together with the 'secondary air', a burnout zone is created, in which a slow combustion of the unburned fuel takes place at relatively low temperatures. The low O_2 concentration provides for NO_X control at this stage.

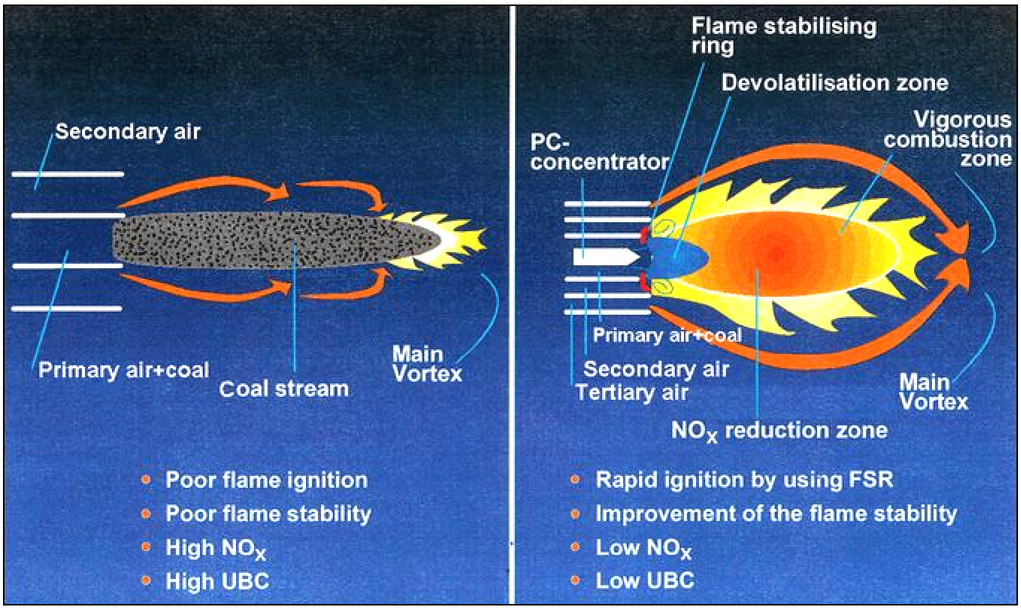

Figure 3.24: Comparison between conventional air-staged and advanced air-staged low NO_X burners
Note: UBC: unburned carbon
[136, Fortum, 2002]

3.4.1.6.2 Flue-gas recirculation low NO_X burner

For solid fuels and for liquid fuels with a nitrogen content between 0.3 and 0.6 wt-%, fuel NO dominates over thermal NO (typically 75 % fuel NO). Therefore, besides flame temperature reduction acting on thermal NO, the oxygen content also needs to be reduced without producing more unburned carbon. The solution was a technique involving separated flames with an internal recirculation of the flue-gas. By injecting a portion of the flue-gas into the combustion zone or combustion air supply, both flame temperatures and oxygen concentrations are lowered enabling a reduction of NO_X formation.

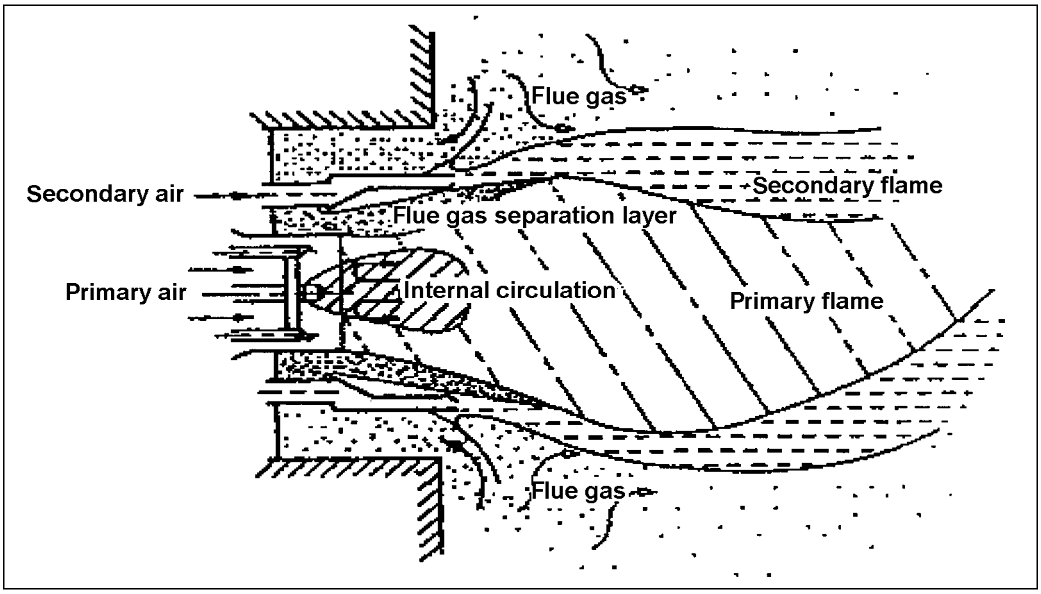

Figure 3.25: Gas/oil flue-gas recirculation low NO_X burner
[32, Rentz, et al., 1999]

The basic function is similar to the air-staged low NO_X burner, but the distances between primary and secondary nozzles are larger, therefore a flue-gas layer develops. In these burners, 15 – 25 % of the hot flue-gas is internally recirculated along with the combustion air into the burnout air. The flue-gas acts as a diluent, reducing the flame temperature and partial pressure of oxygen, thus reducing NO_X formation. Internal recirculation is generally operated in liquid fuel firing and in the latest generation of combined gas and oil LNBs.

3.4.1.6.3 Fuel-staged low NO_X burner

The fuel-staged burner aims to reduce the NO_X already formed by the addition of part of the fuel in a second stage. Fuel-staged LNB is mostly used for gas applications.

This technique begins with combustion of a portion of the fuel with high excess air, making possible relatively low flame temperatures, which inhibit the formation of nitrogen oxides. The internal recirculation zone and the near stoichiometric combustion ensure flame stability. As the combustion goes towards completion in the primary zone, additional fuel (optimum ratio between 20 and 30 %) is injected at a distance downstream of the primary flame to form the secondary flame, which is extremely under stoichiometric. An atmosphere is created in which the NO_X already formed can be reduced to N_2 by NH_3, HCN, and CO radicals. The burnout zone is formed in a third stage. The flame of this type of burner is about 50 % longer than that of a standard gas burner.

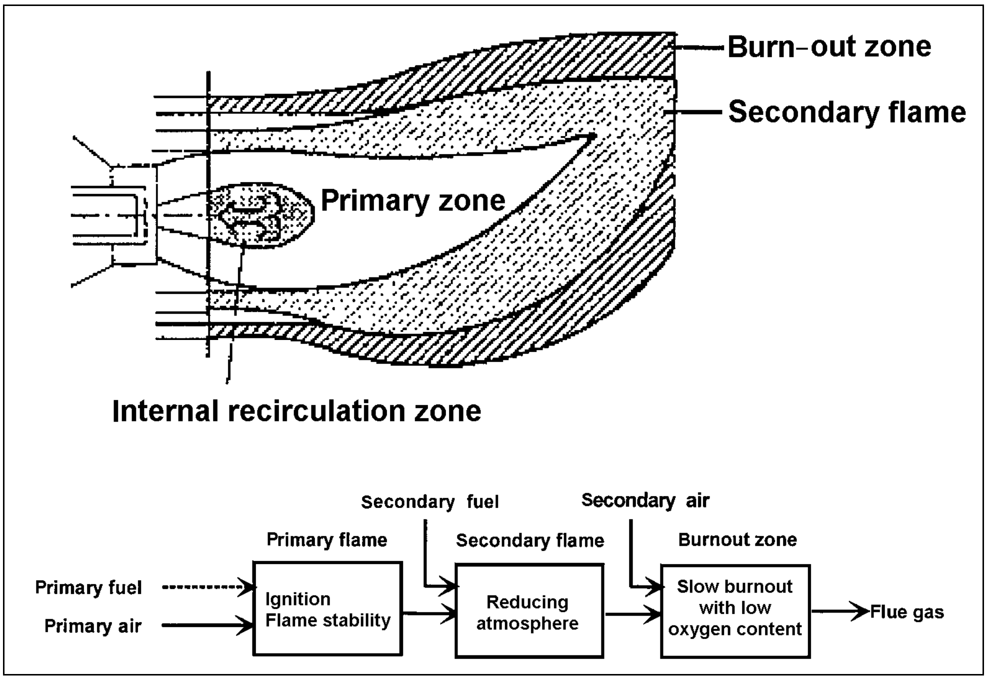

Figure 3.26: Fuel staging at the burner
[32, Rentz, et al., 1999]

3.4.1.6.4 New generation of low NO_X burners

The most recent designs of LNB (called 'hybrid low NO_X burners') use a combination of air-staging, fuel-staging and flue-gas recirculation along with new techniques in order to enable ultra low NO_X emissions. A drawback of first generation low NO_X burners is the need for sufficient room to allow the flame separation: the diameter of low NO_X flames is about 30 to 50 % larger than for classical flames. To reduce this constraint, as well as to reduce NO_X emissions, a new burner has been developed combining separate flames and air-staging. This air-staging is realised by injecting 30 to 40 % of the combustion air, via nozzles, directly into each elementary flame. The swirl of equipment is taken into account in order to avoid 'lost' combustion air, which formerly passed between the bursts of flames but is now directed to where it is needed. This contributes to an improved NO_X reduction, without any increase in unburned carbon. Moreover, the secondary air jets possess a greater impulsion, which 'closes' each flame on the burner axis, reducing the flame diameter to a value similar to the diameter of a classical and compact flame. Therefore, this type of low NO_X burner can also be retrofitted into existing installations.

Low NO_X burners are state-of-the-art in many sectors, however, information about their implementation and operational experience is rather scarce, thus only general information can be given at present. Moreover, for new installations, the additional investment for a low NO_X burner compared to a classical burner can be considered as negligible. For retrofits, eventual modifications on the installation have to be taken into account, which are very often plant specific and thus not quantifiable in general terms. The supplementary operating costs required to operate low NO_X burners are, to a large extent, due to the additional energy consumption, which is necessary due to:

- the need for larger air fans, since larger pressure drops occur across the burners
- the need to ensure improved coal pulverisation, in order to attain efficient combustion under the reduced air conditions experienced in the burners.

Currently dry low NO_X combustors are state-of-the-art for large-sized gas turbines firing natural gas [32, Rentz, et al., 1999]. They are described in more detail in Chapter 7.

3.4.1.7 General performance of primary measures for reducing NO_X emissions

Primary measure		**General NO_X reduction rate***	**General applicability**	**Applicability limitations**	**Remarks**
Low excess air		10 – 44 %	All fuels	• incomplete burnout	• NO_X reduction strongly depends on the emission level of the uncontrolled plant • it might be necessary to seal the furnace, the mills and the air preheater in order to allow application of low excess air firing.
Air staging in the furnace	**Burner out of service (BOOS)**	10 – 70 %	Generally restricted to gas and oil fired plants for retrofit only	Incomplete burn-out (and thus high CO and unburned carbon levels) is valid for 'BOOS', 'BBS' and 'OFA'	• problems may arise maintaining the fuel input, because the same amount of thermal energy has to be supplied to the furnace with fewer operating burners.
	Biased burner firing (BBF)		All fuels for retrofit only		
	Overfire air (OFA)		All fuels		• retrofitting overfire air on an existing boiler involves water-wall tube modifications to create the ports for the secondary air • NO_X reduction of 10 to 40 % is possible for wall-fired furnaces using OFA.
Flue-gas recirculation		20 – 50 % <20 % for coal-fired boilers and from 30 – 50 % for gas-fired plants combined with overfire air	All fuels	• flame instability	• retrofitting an existing boiler with flue-gas recirculation presents some adaptation difficulties, mostly due to efficiency losses of both the boiler and the burners, except when recirculating very small amounts of flue-gas • this NO_X abatement measure can be used for retrofitting when combined with air staging • recirculation of flue-gas results in additional energy consumption due to the recirculation fan.
Reduced air preheat		20 – 30 %	Not suitable for coal-firing wet bottom boilers		• the amount of emission reduction achievable mainly depends on the initial air preheat temperature and on the temperature that is achieved after this measure has been implemented.

*** Notes:**

- if different primary measures to reduce nitrogen oxide emissions are combined the reduction rate can, in general, neither be added nor be multiplied. The combined reduction rate depends on a number of site-specific factors and needs to be validated on a plant-by-plant basis
- not all of the primary measures can be applied to all existing boilers, depending on the combustion configuration and the fuel
- new plants are already fitted with primary measures as part of their basic design.

Table 3.11: General performance of primary measures for reducing NO_X emissions
[33, Ciemat, 2000]

Primary measure		General NO_X reduction rate *	General applicability	Applicability limitations	Remarks
Fuel staging (reburning)		50 – 60 % (70 – 80 % of the NO_X formed in the primary combustion zone can be reduced)	all fuels		• reburning offers some advantages, such as compatibility with other primary NO_X emission reduction measures, simple installation of the technique, use of a standard fuel as the reducing agent, and very small amounts of additional energy. The additional energy consumption by reburning coal over coal can be higher than using natural gas as a reburning fuel • combustion downstream of the primary zone also produces nitrogen oxides • when using natural gas as the reburning fuel, particulate matter, SO_2 and CO_2 are also reduced in direct proportion to the amount of coal replaced.
Low-NO_X burner (LNB)	**Air-staged LNB**	25 – 35 %	all fuels	• flame instability • incomplete burn-out	• low NO_X burners can be used in combination with other primary measures such as overfire air and reburning of flue-gas recirculation • low NO_X burners with overfire air can achieve reduction rates of 35 – 70 % [33, Ciemat, 2000]. • a drawback of first generation low NO_X burners is the space requirement of the flame separation: the diameter of low NO_X flames is about 30 to 50 % larger than for conventional flames.
	Flue-gas recirculation LNB	up to 20 %	all fuels	• flame instability	
	Fuel-staged LNB	50 – 60 %	all fuels	• flame instability • incomplete burn-out	

*** Notes:**

- when combining different primary measures to reduce nitrogen oxide emissions the reduction rate can in general neither be added nor be multiplied. The combined reduction rate depends on a number of side specific factors and needs to be validated on a plant-by-plant basis
- not all of the primary measures can be applied to all existing boilers, their application depends on the combustion configuration and the fuel
- new plants are already fitted with primary measures as part of their basic design.

Table 3.12: General performance of primary measures for reducing NO_X emissions
[33, Ciemat, 2000]

3.4.2 Secondary measures to reduce NO_X emissions

Secondary measures are end-of-pipe techniques to reduce the nitrogen oxides (NO_X) already formed. They can be implemented independently or in combination with primary measures such as a low NO_X burner, etc. Most flue-gas technologies to reduce NO_X emissions rely on the injection of ammonia, urea or other compounds, which react with the NO_X in the flue-gas to reduce it to molecular nitrogen. Secondary measures can be divided into:

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

3.4.2.1 Selective catalytic reduction (SCR)

The selective catalytic reduction (SCR) process is a widely applied process for the reduction of nitrogen oxides in exhaust gases from large combustion installations in Europe and in other countries throughout the world, such as Japan and the US.

The SCR process is a catalytic process based on the selective reduction of nitrogen oxides with ammonia or urea in the presence of a catalyst. The reducing agent is injected into the flue-gas upstream of the catalyst. NO_X conversion takes place on the catalyst surface at a temperature usually between 170 and 510 °C, by one of the following main reactions. Base metal oxide SCR catalysts operating in the above-mentioned temperature range are available on the market and used in numerous applications.

1. With ammonia as a reduction agent:

$$\mathbf{4\,NO + 4\,NH_3 + O_2 \quad \leftrightarrow \quad 4\,N_2 + 6\,H_2O}$$
$$\mathbf{6\,NO_2 + 8\,NH_3 \quad \leftrightarrow \quad 7\,N_2 + 12\,H_2O}$$

2. With urea as a reduction agent:

$$\mathbf{4\,NO + 2\,(NH_2)_2CO + 2\,H_2O + O_2 \quad \leftrightarrow \quad 4\,N_2 + 6\,H_2O + 2\,CO_2}$$
$$\mathbf{6\,NO_2 + 4\,(NH_2)_2CO + 4\,H_2O \quad \leftrightarrow \quad 7\,N_2 + 12\,H_2O + 4\,CO_2}$$

When ammonia is used as the reducing agent, it is usually stored as an aqueous solution or in a liquefied state at a pressure of about 1.7×10^6 Pa (17 bar) at 20 °C. In some smaller applications, i.e. <50 MW, urea is used in the form of white crystal granules, which are dissolved in water before being injected.

The number of installations using liquefied ammonia exceeds the number of installations using other agents, because the cost per kg of ammonia is lower, thus allowing low operating costs. Nevertheless, its properties make handling more difficult compared to the relatively inert aqueous ammonia solution. Ammonia application is required in a range of drinking water reservoirs or river sources and central town sites (i.e. those nearest residential areas), and is also used because the investments for ammonia storage, including safety measures, are lower.

To use, liquefied ammonia has to be evaporated to gaseous ammonia. This is achieved in an evaporator heated electrically, by steam, or hot water. The ammonia is subsequently diluted with air before the mixture is injected into the exhaust gas. The injection takes place through a system of nozzles to achieve a homogeneous mixing of ammonia with the flue-gas. A static mixer can be placed in the exhaust gas channel to further improve mixing. In order to obtain a high NO_X removal efficiency and to minimise the NH_3-slip, it is of particular importance to achieve a homogeneous NH_3/NO_X ratio in the flue-gas. But the strongest argument to avoid ammonia-slip (over 2 ppm) in coal fired combustion plants is, that the fly ash cannot be sold to the building industry.

Given a maximum achievable ammonia-slip, the degree of NO_X removal depends on the catalyst used: at high NH_3/NO_X ratios, a high NO_X removal efficiency can be obtained, but simultaneously the amount of unused ammonia (NH_3 slip) in the clean flue-gas increases considerably. The so-called ammonia-slip should be as low as possible, in order to avoid the risk of NH_3 reacting with SO_3 in the flue-gas during cooling of the flue-gas, which can lead to fouling and corrosion of the heating surfaces by ammonium bisulphates formed.

The catalysts used can have different geometrical form such as honeycomb or plate type catalysts as shown in Figure 3.27. Pellets (especially for activated carbon) are also used as the catalyst geometry.

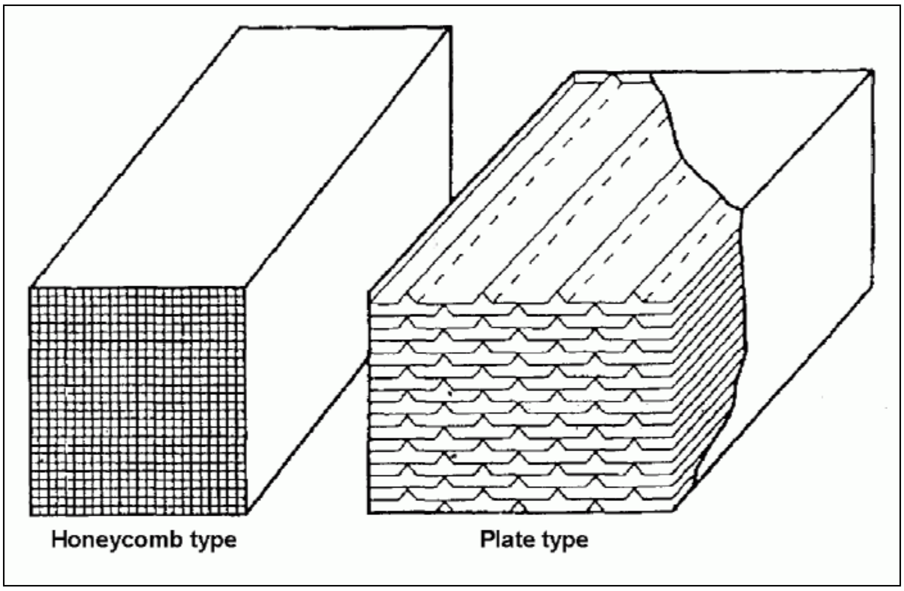

Figure 3.27: Honeycomb or plate type catalysts
[33, Ciemat, 2000]

Four different base materials have been tested. Long-term experience is available only for two materials. For zeolites, one LCP application has been in operation for more than 10 years, although it has had to be rebuilt due to losses of catalytic material. Some LCP applications have also been realised with activated coke.

The four types of materials used as catalysts with SCRs are:

- **base metal oxides**, which consist of the base material TiO_2 together with the active components vanadium, tungsten, molybdenum. In most cases, V_2O_5 is used with small amounts of WO_3, added in order to extend the narrow temperature window, and small amounts of SiO_2 in order to stabilise the structure and small amounts of MoO_3 in order to make the catalyst more resistant to poisoning from exhaust gas constituents. This type of catalyst requires a temperature range of 300 – 450 °C
- **zeolites**, which are crystalline, highly porous natural or synthetic alumino-silicates, and are used at temperatures between 350 and 600 °C
- **iron oxides**, which consist of iron oxide particles with a thin crystalline cover of iron phosphate
- **activated carbon**, which consists either of pulverised hard coal or brown coal, mixed with inert elements and worked up to sintered pellets. Due to thermal instability of activated carbon at higher temperatures, low operating temperatures of 100 – 220 °C are required. As a result, in power stations, activated carbon can only be employed in the ‘tail-end’ configuration.

Catalysts are manufactured in a number of different channel diameters. The choice of the channel diameter is optimised after a study of the dust content in the exhaust gas, the characteristics of the dust, and the allowable pressure drop across the SCR reactor. The deposit of dust should be minimised and the pressure drop over the catalyst kept low. The volume of the catalyst required depends on the characteristics of the catalyst, such as its activity characteristics, and on operating conditions such as flue-gas volume, the required NO_X reduction, gas composition, flue-gas temperature and the presence of catalyst poisons. The individual catalyst elements are then packed together in a catalyst module, which then forms the catalyst layers in the SCR reactor, as can be seen in Figure 3.28.

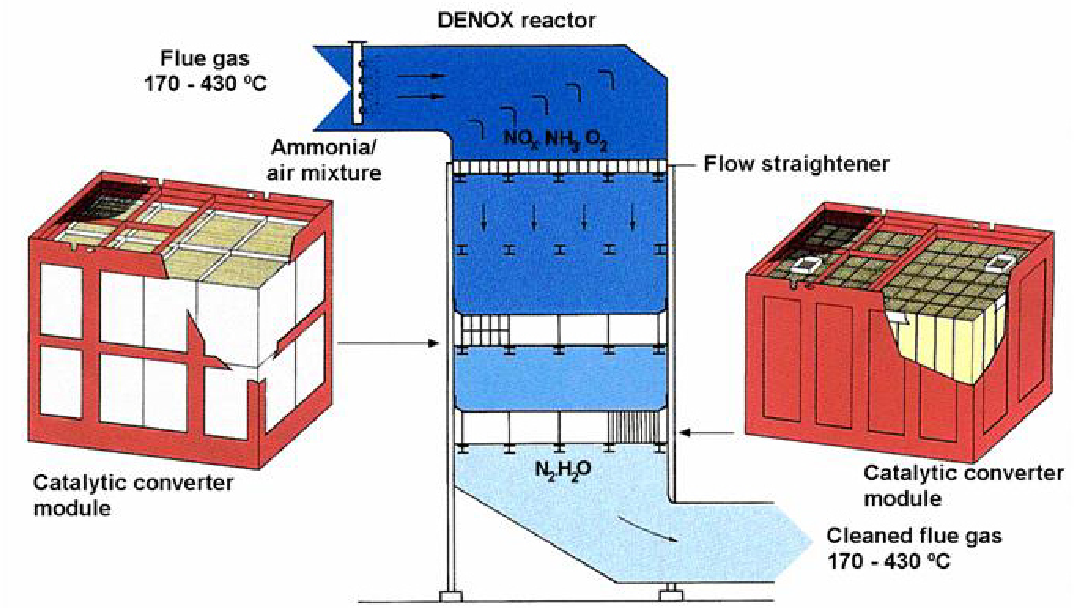

Figure 3.28: Configuration of catalyst reactor, element, module and layers
[33, Ciemat, 2000]

Current estimates of catalyst lifetime range from 6 – 10 years in coal-fired units and 8 – 12 years in oil- and gas-fired units. Catalyst replacement rates depend on several site-specific factors such as equipment type, fuel characteristics, capacity, plant operation, inlet NO_X concentration, NO_X reduction rate, ammonia/urea to NO_X ratio, and allowable ammonia slip. In recent years, catalyst formulations more resistant to thermal and mechanical damage and to poisoning from contaminants have been commercialised. Regeneration is a new commercial application to extend the catalyst lifetime whereas a successful regeneration cannot be expected in all cases.

There are three basic configurations for integrating the SCR reactor into the flue-gas cleaning chain, the main factor being that the conditions, such as flue-gas temperature, are right for the catalyst used. The positions that are utilised for the catalyst are shown in Figure 3.29.

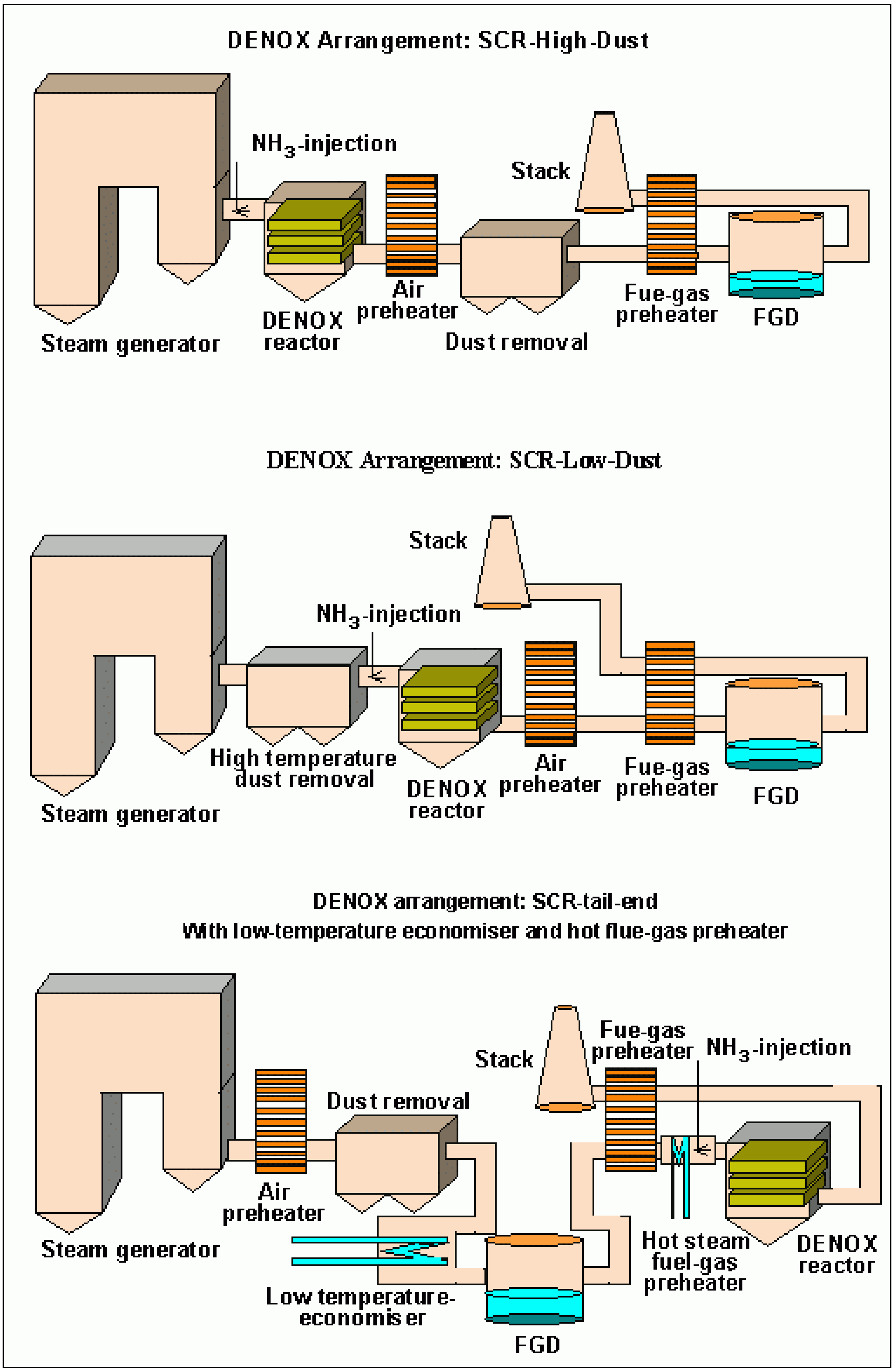

Figure 3.29: Existing configurations of abatement technologies

The three configurations are high-dust, low-dust and tail-end:

- the **high-dust** arrangement is the most commonly implemented, and avoids the flue-gas reheating due to the high operating temperature of the catalyst (Figure 3.30). The lifetime of the catalyst has been improved as well as its resistance to abrasion. However, its use has two drawbacks: first, the flue-gas may contain fly ash and catalyst poisons, which results in catalyst deactivation, followed by a decrease in NO_X reduction efficiency. This may occur in, e.g. slag tap furnaces, for specific fuels or in co-combustion processes. Secondly, for retrofitting with an SCR in the high-dust configuration, additional space is required near the boiler The high-dust arrangement is cost effective for many installations and most commonly implemented
- the **low-dust** arrangement bypasses the drawbacks of the high-dust configuration. Its major advantage is the lowered mechanical strain on the catalyst, which can be expected to extend the catalyst's lifetime. However, because the process operates without supplementary heating, the installation of high temperature dust precipitators is necessary. Therefore, this configuration often proves to be uneconomic when retrofitting old power plants. Moreover, the air heater is more subjected to the deposition of ammonium bisulphate
- the **tail-end** arrangement is a favourable variant for existing plants, due to the exposure of the catalyst to abrasion, corrosion, and deactivation. Also the catalyst volume is smaller than for the high-dust configuration, because a catalyst with a smaller pitch can be used. However, the incoming flue-gas has to be reheated by additional burners that mainly use natural gas to reach the operating temperature of the catalyst. For an activated coke catalyst, a heat exchange from the raw gas to the clean gas is usually sufficient.

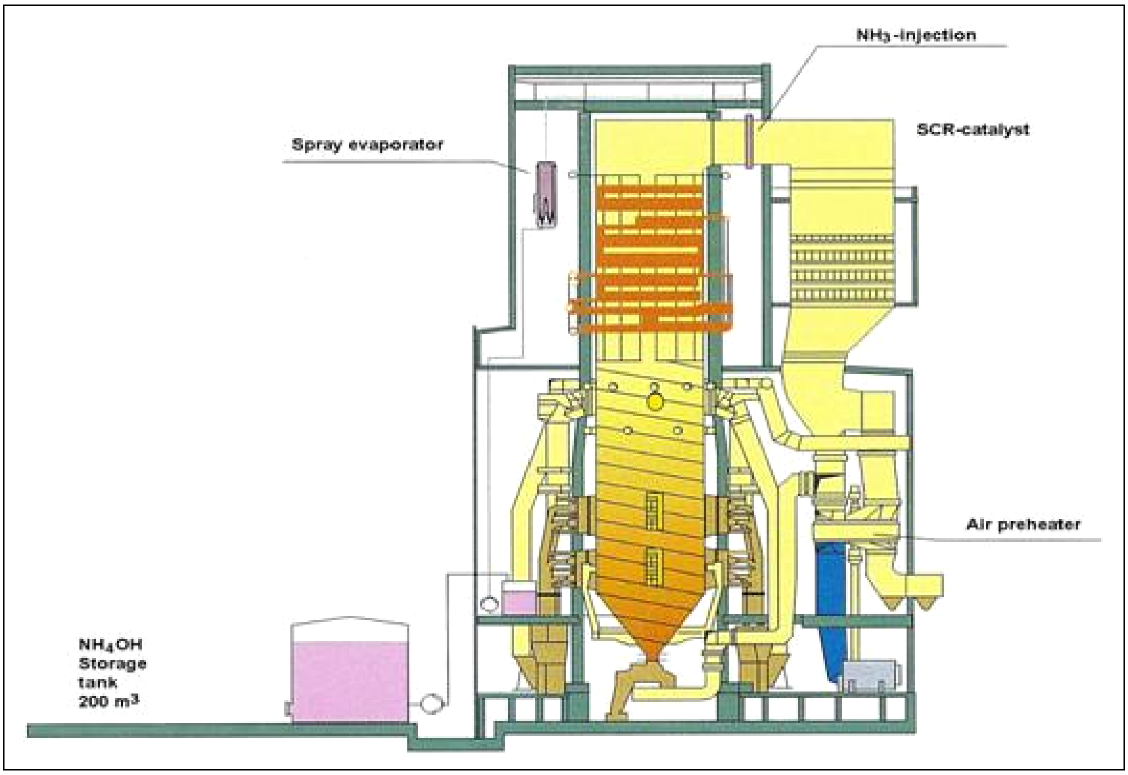

Figure 3.30: Example of a high-dust SCR catalyst
[34, Verbund, 1996]

One possible disadvantage of the SCR is related to the ammonia-slip. This occurs due to the incomplete reaction of NH_3 with NO_X, when small amounts of NH_3 leave the reactor with the flue-gas. This effect is known as the ammonia-slip (NH_3 slip). The ammonia-slip increases with increasing NH_3/NO_X ratio and with decreasing catalyst activity. High ammonia slip (NH_3 break through) can lead to:

- the formation of ammonium sulphates, which are deposited on downstream facilities such as the catalyst and air preheater
- NH_3 in flue-gas desulphurisation waste waters and air heater cleaning water, and
- increased NH_3 concentration in the fly ash.

The main advantages of the SCR technology are:

- the SCR process can be used for many of the fuels used in combustion processes, e.g. natural gas and light oils, as well as process gases and coal
- the conversion of NO_X does not create any secondary pollution components
- the emission of NO_X can be reduced by 90 % or more
- the overall NO_X reduction depends on SCR and primary measures
- to meet air quality requirements SCR can be applied with adapted NH_3 consumption to reduce NH_3 slip effects and to increase catalyst lifetime.

The investment costs of an SCR device are considerable (Figure 3.31). The price per tonne of NO_X reduced varies between boiler types. Tangentially-fired boilers have higher costs per tonne of NO_X reduced, because they have lower original emission levels. The reactant costs are relatively lower than in the SNCR plants.

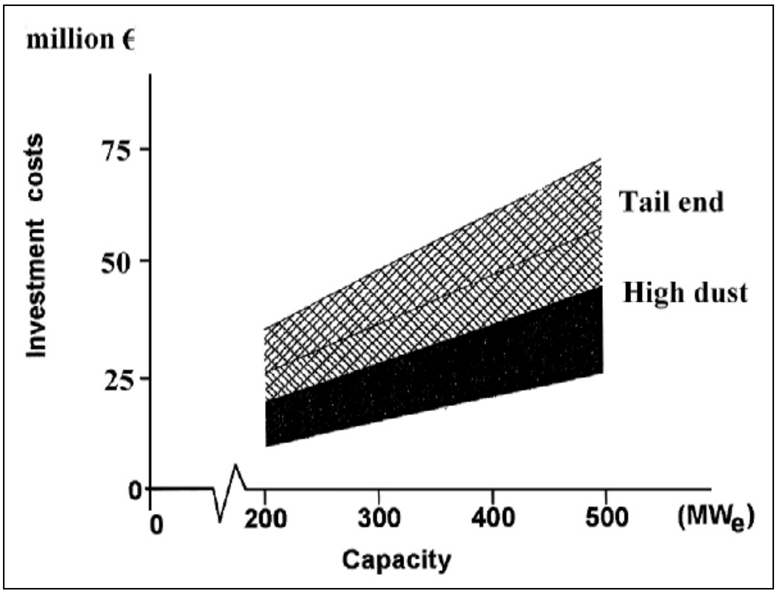

Figure 3.31: Investment costs for a SCR process at a combustion plant
[58, Eurelectric, 2001]

Investment costs of an SCR unit depend on the volume of the catalyst which is fixed by the flue-gas volume, by the ammonia slip and by the NO_X conversion rate which should be attained. In cost estimations carried out for power plants costs for catalyst were estimated to be in the range of EUR 10000 to 15000 per m^3. For a given flue-gas volume of 1 million m^3/h, investment costs for an SCR unit were estimated to be EUR 15 million (raw dust arrangement; including planning, erection and all surrounding equipment such as pipework, pumps, fans, etc., but without the catalyst). The main factors for operating costs are the lifetime of the catalyst which is influenced by the fuel characteristic and the SCR configuration (low-dust, high-dust, tail-end), demand on the reduction agent, energy consumption due to pressure loss and eventually energy for reheating of the flue-gas.

On the basis of operators information and market prices of the past 5 years (Austrian and German plants), investment costs for an SCR unit were estimated by using the following formula:

Investment cost (I.C.) for an SCR unit treating a flue-gas volume of x million m^3/h:

$$\textbf{I.C.} = (\textbf{x million m}^3 \textbf{ flue-gas volume/1 million m}^3)^{0.7} * \textbf{EUR 15 mllion}$$

Costs for erection and for electronic, monitoring and control equipment are included. Costs for catalysts are excluded, which are estimated to be in the range of EUR 15.000/m^3. Costs were estimated for the raw gas arrangement only. The main cost factors amongst investment and maintenance costs are costs for catalyst displacement, reduction agent (aqueous solution of ammonia) and electric energy. In the investment costs, costs for the whole flue-gas channel are included (pipes, catalyst box, bypass, NH_4OH unit consisting of tank, storage system, dosing device, evaporation and mixing system).

In the next table costs were estimated for an SCR unit treating a flue-gas volume of 200000 m^3/h, 500000 m^3/h and 1000000 m^3/h with a raw gas concentration of 500 mg/Nm^3 (attained by primary measures) and 350 mg/Nm^3 (attained by primary measures and an SNCR respectively). Clean gas concentration is, in both cases, assumed to be 100 mg/Nm^3.

Parameter	**Unit**	**Flue-gas volume (Nm^3/h)**		
		200000	**500000**	**1000000**
NO_X-concentration to be reduced	g/Nm^3		0.25 – 0.4	0.25 – 0.4
Operating hours	h/yr	5000	5000	5000
Reduced load	t/yr	250 – 400	625 – 1000	1250 – 2000
Investment costs	EUR million	4.86	9.23	15.0
Yearly repayment [1]	EUR million/yr	0.50	0.95	1.54
Operating costs (including costs for electr. energy,. catalysts,. reducing agents,. maintenance, and wear and tear)	EUR million/yr	0.25 – 0.29	0.60 – 0.69	1.17 – 1.34
Yearly costs	EUR million/yr	0.75 – 0.79	1.56 – 1.64	2.72 – 2.88
Yearly specific costs	EUR/t NO_X	1968 – 3016	1638 – 2488	1442 – 2175
Note 1: basis 15 years with a 6% interest rate				

Table 3.13: Cost estimations for SCR units after power plants as a function of the flue-gas volume

With tail-end devices, the flue-gases may have to be reheated before the stack. This may take up as much as 2 % of the electric capacity of the plant. In applications which do not need reheating, the operating costs are mainly related to the cost of the reagent.

System capital costs for retrofit applications removing between 60 and 90 % NO_X range between EUR 50/kW and EUR 100/kW, where the costs for larger plants are at the lower end of this range and the costs for smaller plants at the higher end. The main factors contributing to full retrofit costs for SCR systems on coal plants with a target NO_X emission level of 185 mg/Nm^3 are unit size, inlet NO_X concentrations and the varying construction needs associated with the level of retrofit difficulty. For instance, an increase in baseline inlet NO_X concentration from 615 mg/Nm^3 to 1230 mg/Nm^3 will increase the SCR capital costs by around 50 %. As unit size decreases from 1000 MW_e to 200 MW_e, the initial SCR capital cost can decrease by up to 30 %. The scope of retrofit determined fan upgrades, duct work, structural steel and foundation changes can impact costs by around 20 to 35 %. Operating costs for the reducing agent are approximately EUR 75 per tonne NO_X for anhydrous ammonia or EUR 125 per tonne of NO_X for a 40 % urea solution. Overall costs, i.e. investment and operating costs, for NO_X reduction in an 800 MW power plant using an SCR range between EUR 1500 and 2500 per tonne of NO_X reduced [167, Rigby, et al., 2001].

The capital costs of an SCR for gas turbines or internal combustion engines are in the range of EUR 10 to 50/kW (based on electrical output). These costs are considerably lower than for the application of an SCR to a coal-fired plant.

The price of regenerated SCR catalysts is up to 50 % of new catalysts. Without severe erosion effects, the limited lifetime of deactivated high dust SCR catalysts can be prolonged by regeneration with an impact on operation costs compared to new catalysts.

3.4.2.2 Selective non-catalytic reduction (SNCR)

The selective non-catalytic reduction (SNCR) process is another secondary measure to reduce nitrogen oxides already formed in the flue-gas of a combustion unit. It is operated without a catalyst at a temperature of between 850 and 1100 °C. This temperature window strongly depends on the reagent used (ammonia, urea or caustic ammonia).

Using ammonia as a reagent, the following chemical reactions take place more or less at the same time. At the lower temperature, both reactions are too slow, at the higher temperature, the unwanted by-reaction dominates with an increase of NO_X emissions.

main reaction:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \quad \textbf{(reduction)}$$

unwanted by-reaction:

$$4\ NH_3 + 5\ O_2 \rightarrow 4\ NO + 6\ H_2O \qquad \textbf{(oxidation)}$$

An SNCR facility consists of two operational units:

- the reagent storage unit, including storing, cooling, and evaporation of the reagent
- the SNCR unit itself, where the injection of the reagent and the reaction of nitrogen oxides to nitrogen and water take place.

The temperature window is of considerable importance as, above this, ammonia is oxidised and so even more NO_X is produced, and below this, the conversion rate is too low and ammonia can be formed. Moreover, with load changes the required temperature window is subjected to fluctuations in the boiler. To adjust the required temperature window with the ammonia injection, several levels of injection are necessary. The SNCR process with different injection levels of ammonia is shown in Figure 3.32.

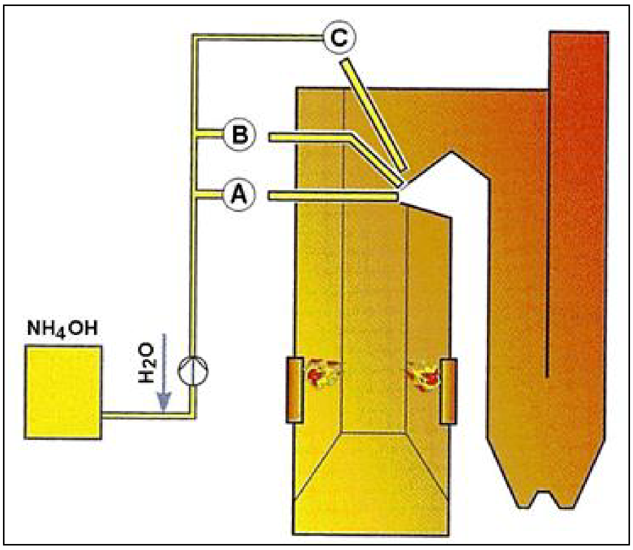

Figure 3.32: The SNCR process
[34, Verbund, 1996]

In order to achieve a high abatement rate and a low NH_3 slip, reagent and NO_X in the flue-gas must undergo sufficient mixing. Besides distribution and mixing, another relevant parameter is the size of reagent drops. Small drops would evaporate too quickly and react at too high temperatures inducing a reduced NO_X abatement rate, whereas extremely large drops would evaporate too slowly and react at too low temperatures resulting in increased NH_3 slip.

Possible carriers for the reducing agent are pressurised air, steam or water. Primary measures, such as overfire air or flue-gas recirculation, can be used as a reagent carrier for the SNCR process.

The choice of the reagent also influences the formation of nitrous oxide (N_2O). Using ammonia and caustic ammonia induces negligible amounts of N_2O, whereas relatively high amounts could be measured when injecting urea directly into the boilers. To overcome this problem and to nearly eliminate N_2O formation, urea can be injected into the burnout air. Moreover, the use of urea as a reagent for the SNCR leads to higher corrosion problems than with ammonia and caustic ammonia. Therefore, materials should be chosen carefully.

Most problems with SNCR applications are related to non-uniform distribution of the reagent within the combustion chamber. Therefore, optimisation of the distribution system is required. Special distribution systems are used to gain an optimal distribution of ammonia and flue-gas.

The reaction of nitrogen oxides and ammonia/urea into water and nitrogen strongly depends on the temperature and retention time within the required temperature range, as well as on the ammonia to nitrogen oxides ratio. As already mentioned, the temperature window for ammonia and caustic ammonia is 850 to 1000 °C, with the optimum temperature being 870 °C. In comparison, the temperature window, when using urea, is wider (800 to 1100 °C), with an optimal temperature at 1000 °C.

The retention time within the required temperature window ranges from 0.2 to 0.5 seconds. This contact time range is rather unstable, and therefore the ammonia to nitrogen oxides ratio must be ammonia-rich rather than stoichiometric. Once more, optimisation is required as regards the molar ratio of NH_3 to NO_X. The NO_X removal rate is favoured by an increased ratio, but in the meantime the ammonia slip increases too, leading to increased pollution of subsequent units (e.g. heat-exchangers, flue-gas ducts). In order to neutralise these two contrary effects, a NH_3 to NO_X ratio of between 1.5 and 2.5 has been found to be the optimum.

The equipment for the SNCR process is quite easy to install and does not take up too much space, even if, in almost every case, more than one injection level is needed. SNCR has a low reduction rate, so it can be used alone in boilers which already have quite low emission levels. It can also be useful in boilers equipped with a primary reduction technique. However, it is not very useful for boilers with load variations or with variable fuel quality.

The actual construction costs depend on the boiler and its operating profile. According to some estimations, the costs are approximately EUR 2500 per tonne of reduced NO_X in a coal-fired 250 MW_{th} boiler operating for 4000 h/yr.

3.4.2.3 Safety aspects of ammonia storage

Both SCR and SNCR techniques use ammonia or urea as a reducing agent. Urea is more commonly used in combustion plants below 50 MW_{th}, than in large SCR or SNCR applications. No impact on health arises from solid urea storage.

Ammonia is a combustible gas that can be stored as an aqueous solution or in a liquid state at a pressure of about 1.7 MPa (17 bar) at 20 °C. Because of the high risk of ammonia to human health, ammonia transportation, handling and storage needs to be carried out very carefully to avoid any leakage. Monitoring systems have to be installed for the detection of low ammonia concentrations around the ammonia storage and handling area. Pressurised and hydrous ammonia are regulated under the Seveso II Directive 96/82/EC and correlated national regulations.

The stress corrosion risk of steel vessels requires regular monitoring of tank integrity and quality control for hydrogen and oxygen traces in the supplied liquid ammonia.

3.4.2.4 General performance of secondary measures for reducing NO_X emissions

Secondary measure	General NO_X reduction rate	Other performance parameters		Remarks
		Parameter	Value	
Selective catalytic reduction (SCR)	80 – 95 %	Operating temperature	350 – 450 ºC (high-dust) 170 – 300 ºC (tail-end) 280 – 510 ºC (gas tubines) 200 – 510 ºC (diesel engines)	• the ammonia slip increases with increasing NH_3/NO_X ratio, which may cause problems, e.g. with a too high ammonia content in the fly ash. This is a problem which can be solved by using a larger catalyst volume and/or by improving the mixing of NH_3 and NO_X in the flue-gas • incomplete reaction of NH_3 with NO_X may result in the formation of ammonium sulphates, which are deposited on downstream facilities such as the catalyst and air preheater, increased amounts of NH_3 in flue-gas desulphurisation waste waters, the air heater cleaning water, and increased NH_3 concentration in the fly ash. This incomplete reaction only occurs in the very unlikely case of catastrophic failures of the whole SCR system • the life of the catalyst has been 6 – 10 years for coal combustion, 8 – 12 years for oil combustion and more than 10 years for gas combustion • catalyst lifetime of 40000 to 80000 operating hours can be reached by periodical washing.
		Reducing agent	Ammonia, urea	
		NH_3/NO_X ratio	0.8 – 1.0	
		NH_3-slip	<5 mg Nm^3	
		Availability	>98 %	
		SO_2/SO_3-conversion rate with catalyst	1.0 – 1.5 % (tail end)	
		gyConsumption as % of electric capacity	0.5 % for all applications	
		Pressure drop at the catalyst	4 – 10 (10^2 Pa)	
Selective non-catalytic reduction (SNCR)	30 – 50 %	Operating temperature	850 – 1050 ºC	• though some manufacturers report a NO_X reduction level of over 80 %, the common view is that SNCR processes are, in general, capable of 30 – 50 % reduction as an average covering different operational conditions. Further NO_X reductions can be obtained on specific boilers where the conditions are good, as well as lower values where the conditions are bad, sometimes on existing plants [33, Ciemat, 2000]. • SNCR cannot be used on gas turbines because of the residence time and temperature window required • incomplete reaction of NH_3 with NO_X may result in the formation of ammonium sulphates, which are deposited on downstream facilities such as the air preheater, increased amounts of NH_3 in flue-gas desulphurisation waste waters, the air heater cleaning water, and increased NH_3 concentration in the fly ash • SNCR cannot be used for gas turbines or engines.
		Reducing agent	Ammonia, urea	
		NH_3/NO_X ratio	1.5 – 2.5	
		Availability	>97 %	
		NH_3 slip	<10 mg Nm^3	
		Energy consumption as % of electric capacity	0.1 – 0.3 %	
		Residence time within temperature range	0.2 – 0.5 sec	

Table 3.14: General performance of secondary measures for reducing NO_X emissions

3.5 Combined techniques to reduce sulphur oxide and nitrogen oxide emissions

Combined SO_2/NO_X removal processes have been developed with the aim of replacing conventional FGD/SCR processes. Some of the combined SO_2/NO_X removal processes have been applied only in a very small number of units or exist more or less only as demonstration plants and have not yet found a market penetration for commercial (cost) reasons. Each of these techniques employs a unique chemical reaction to remove SO_2 and NO_X simultaneously. The development of combined techniques has been forced by a major problem of conventional SCR followed by FGD technology, which is related to the oxidation of SO_2 in the SCR reactor. Usually 0.2 – 2 % of the SO_2 is oxidised to SO_3. This has various effects on the flue-gas cleaning system. For low sulphur coal for instance, SO_3 may improve the removal efficiency of a cold-side ESP. However, SO_3 usually increases the deposits and corrosion in the air preheater and gas-gas heat-exchanger.

Combined SO_2/NO_X removal processes can generally be divided into the following categories:

- solid adsorption/regeneration (desorption)
- gas/solid catalytic operation
- electron beam irradiation
- alkali injection
- wet scrubbing.

Within these categories several processes are still under development whereas other techniques are already commercially available and in operation in a number of plants.

3.5.1 Solid adsorption/regeneration

This type of process employs a solid sorbent or catalyst, which adsorbs or reacts with SO_2 and NO_X in the flue-gas. The sorbent or catalyst is regenerated for re-use. Sulphur or nitrogen species are liberated from the sorbent in the regeneration step, which generally requires a high temperature or reducing gas for a sufficient residence time. The recovered sulphur species are processed for example in a 'Claus' plant to produce elemental sulphur, a saleable by-product. The nitrogen species are decomposed into N_2 and water by injection of ammonia or by recycling to the boiler. Other processes such as the activated carbon process, NOXSO, copper oxide, zinc oxide and magnesium oxide-vermiculite are involved in solid adsorption/regeneration.

3.5.1.1 Activated carbon process

As activated carbon has a very large specific surface area, it has been used widely as an air cleaning and waste water treatment agent since the nineteenth century. It has also been known for a long time that activated carbon adsorbs SO_2, oxygen, and water to produce sulphuric acid. Simultaneous SO_2 and NO_X removal becomes possible by adding ammonia.

The flue-gas from the boiler is first dedusted, passed through a heat-exchanger where heat is extracted for activated carbon regeneration, and then cooled in a water pre-scrubber. The gas enters the first stage of the activated carbon (dry porous charcoal) bed at a temperature of 90 – 150 ºC. The sulphur dioxide reacts with oxygen and water vapour in the flue-gases (through catalytic oxidation) to form sulphuric acid, which is absorbed on the activated carbon.

Prior to entering the second stage adsorber, ammonia is injected into the flue-gases in a mixing chamber. Nitrogen oxides react catalytically with the ammonia in the second stage to form nitrogen gas (N_2) and water. The cleaned flue-gases and liberated nitrogen and moisture pass to the stack for discharge. The reduction process takes place in an adsorber, where the activated carbon pellets are transported from the top to the bottom in the form of a moving bed. The gas flows across the layers, first entering the lowest part of the bed.

The sulphur-laden activated carbon passes to a regenerator where desorption is performed thermally, by indirect heating using heat extracted earlier from the flue-gases, at a temperature of about 400 – 450 ºC. Carbon dust is removed and make-up pellets added prior to recycling them back to the absorber. As a result of the regeneration, enriched SO_2 gas is generated from the desorber. The enriched gas is converted, by using a Claus or another process, to elemental sulphur, or sulphuric acid that can be sold as a by-product. Figure 3.33 shows a schematic diagram of the activated carbon process.

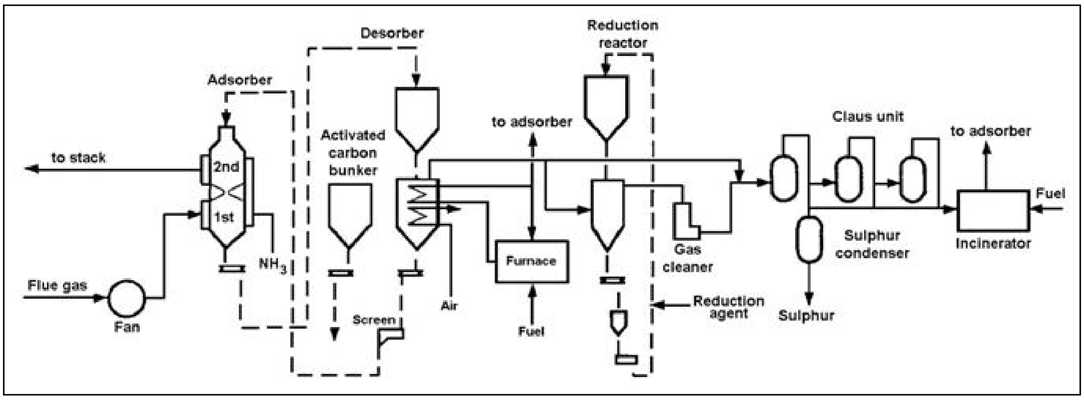

Figure 3.33: The activated carbon process
[33, Ciemat, 2000]

3.5.1.2 The NOXSO process

The NOXSO process is expected to achieve a SO_2 reduction of 97 % and NO_X reduction of 70 %. The flue-gas is cooled by evaporating a stream of water sprayed directly into the ductwork. After being cooled, the flue-gas is passed through two parallel fluidised bed adsorbers where SO_2 and NO_X are removed simultaneously by the sorbent.

The sorbent consists of spherical beads of high surface-area alumina, impregnated with sodium carbonate. The cleaned flue-gas then passes to the stack. The spent sorbent is transported to the sorbent heater which is a three-stage fluidised bed. During the heating process at 600 °C, NO_X is desorbed and partially decomposed. The hot air containing the desorbed NO_X is recycled to the boiler, where the NO_X is converted to N_2 releasing either CO_2 or H_2O by reaction with free radicals in the reducing atmosphere of the combustion chamber. The sulphur is recovered from the sorbent in a moving bed regenerator where sulphur compounds on the sorbent (mainly sodium sulphate) react with natural gas (methane) at high temperature to produce an off-gas with high concentrations of SO_2 and hydrogen sulphide (H_2S). About 20 % of the sodium sulphate (Na_2SO_4) is reduced to sodium sulphide (Na_2S) which must subsequently be hydrolysed in the steam treatment vessel. A moving bed, steam treatment reactor follows the regenerator, and a concentrated stream of H_2S is obtained from the reaction of steam with Na_2S. The off-gases from the regenerator and steam treatment are processed in a Claus plant to produce elemental sulphur, a saleable by-product. The sorbent is cooled in the sorbent cooler and then recycled to the adsorber.

3.5.1.3 Other solid adsorption/regeneration processes

Other processes such as the copper oxide and the zinc oxide process are still being developed and are, therefore, not discussed further in this part of the document.

3.5.2 Gas/solid catalytic processes

This type of process employs catalytic reactions such as oxidation, hydrogenation, or SCR. Elemental sulphur is recovered as a by-product. Waste water treatment is not required. WSA-SNOX, DESONOX, SNRB, ‘Parsons Flue-gas Clean-up’ (FGC) and ‘Lurgi Circulating Fluidised Bed’ (CFB) are included in this category. Some processes are now starting to be commercialised.

3.5.2.1 WSA-SNOX process

This process employs two catalysts sequentially to remove NO_X by SCR and to oxidise SO_2 to SO_3, condensing the latter as sulphuric acid for sale. About 95 % of the sulphur and nitrogen oxides in the flue-gas can be removed. The process produces no waste water or waste products, nor does it consume any chemical apart from ammonia for NO_X control. Figure 3.34 shows a flow diagram of the WSA-SNOX process installed in a 300 MW_e coal-fired power plant in Denmark.

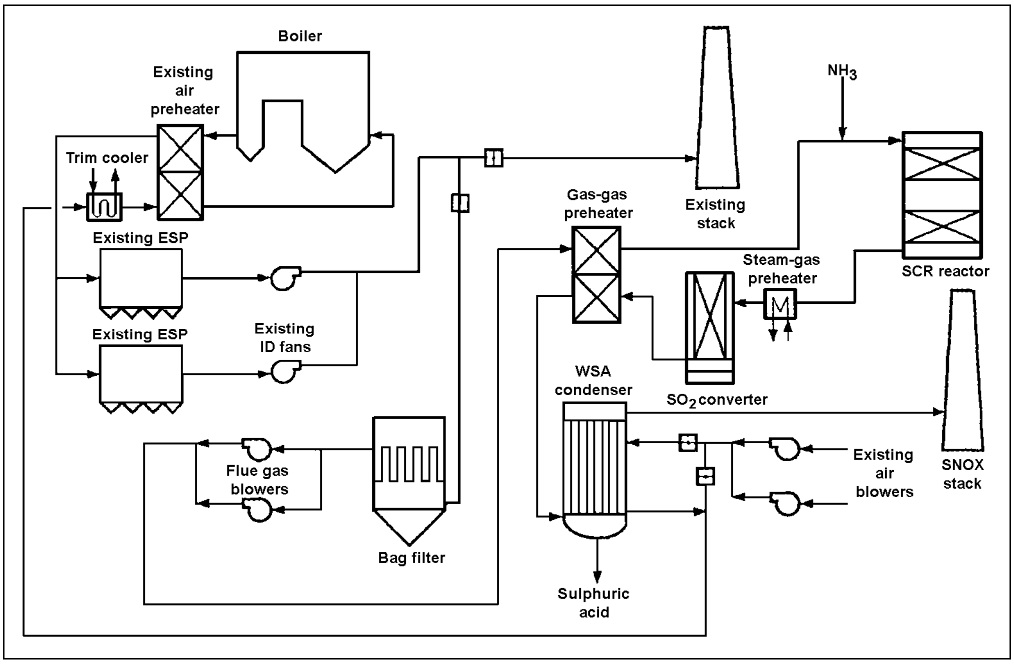

Figure 3.34: WSA-SNOX process
[33, Ciemat, 2000]

Here, flue-gas leaving the air preheater is treated in a particulate control device and passes through the cold-side of a gas-gas heat-exchanger, which raises the gas temperature to above 370 °C. An ammonia and air mixture is then added to the gas prior to the SCR, where nitrogen oxides are reduced to N_2 and water.

As the flue-gas leaves the SCR, its temperature is adjusted slightly, and it then enters the SO_2 converter, which oxidises SO_2 to sulphur trioxide (SO_3). The SO_3-laden gas passes through the hot side of the gas-gas heat-exchanger where it is cooled as the incoming flue-gas is heated. The processed flue-gas then enters a falling film condenser (the WSA-condenser) where it condenses out of the gas phase on to borosilicate glass tubes and is subsequently collected, cooled, and stored. Cooled air leaves the WSA-condenser at over 200 °C and is used as combustion air after collecting more heat through the air preheater.

In this process, it is possible to recover thermal energy from the SO_2 conversion, SO_3 hydrolysis, sulphuric acid condensation and the DENOX reaction. The recovered energy is used for increased steam production. Hence, the absolute decrease in net efficiency is as low as 0.2 % at a 300 MW_e plant (with 1.6 % sulphur coal). Typically each per cent of sulphur in the coal results in 1 % additional steam production. When the coal contains 2 – 3 % sulphur, the steam production is considered to compensate for the power consumption of the WSA-SNOX process.

3.5.2.2 DESONOX process

In the DESONOX process (Figure 3.35), flue-gases are first passed through an ESP to remove particulates, followed by ammonia injection and SCR. The gases are then cooled by preheating combustion air, and reheating the fully treated flue-gases prior to release to the atmosphere. The temperature of the flue-gas is thus reduced to approximately 140 °C, which enables the catalytic oxidation of SO_2 to SO_3 and its subsequent condensation as sulphuric acid (70 %). The latter step is accomplished in a recirculating acid tower. The flue-gases are finally directed through a wet electrostatic mist precipitator and are reheated prior to release.

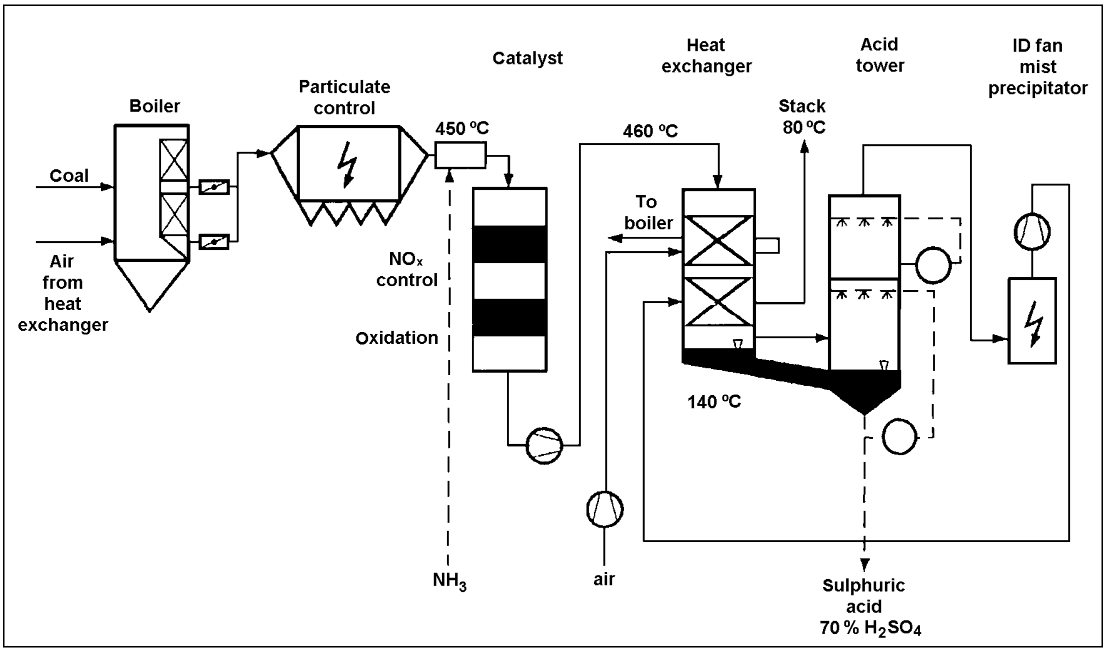

Figure 3.35: DESONOX process
[33, Ciemat, 2000]

3.5.2.3 The SNRB process

In the SO_X-NO_X-ROX-Box process (SNRB), a dry sorbent such as lime or sodium bicarbonate is injected into the flue-gas upstream of a specially designed filter arrangement. This process combines the removal of SO_2, NO_X and particulates in one unit – a high temperature catalytic ceramic or fabric filter. The process requires less space than conventional flue-gas cleaning technology. The SNRB process aims to remove up to 90 % of the SO_2 and NO_X and at least 99 % of the particulates, but no information is also available wether this process is actually applied to a large combustion plant. Therefore, no information on the general performance of the SNRB process can be given.

3.5.2.4 Emerging gas/solid catalytic processes

Other processes which are currently being developed are the ‘Parsons Flue-gas Clean-up’ process and the ‘Lurgi CFB’ process. These processes have only been installed on a pilot plant scale and are, therefore, not presented in this part of the document.

3.5.3 Electron beam irradiation

This process exposes the flue-gas to a high energy flux of electrons with ammonia to generate particulates (ammonium sulphate or nitrates) for collection by an ESP or bag filter. The flue-gas passes through a spray cooler and heat-exchanger where defined temperature (65 – 90 °C) and humidity levels are established. In the electron beam reactor, flue-gas is irradiated by a beam of high energy electrons in the presence of a near stoichiometric amount of ammonia which has been added to the flue-gas upstream of the reactor. In the irradiation zone, the nitrogen, oxygen and water compounds of the flue-gas are excited by high energy electrons to form radicals and ions. These species are able to start oxidation reactions with SO_2 and NO_X and produce sulphuric acid and nitric acid, respectively. These acids are neutralised by ammonia. The ammonia salt particles are then removed from the flue-gas by means of a particulate control device. This by-product is saleable as an agricultural fertiliser.

Processes differ in terms of the method of exposing the flue-gas to the energy flux, and the control equipment employed to form and collect the particulates. This is a unique combined SO_2/NO_X removal process in that both SO_2 and NO_X are converted to useful by-products while NO_X is converted to N_2 and water in other processes. However, these systems have so far only been tested on pilot plant scale, therefore, there is no information on their general performance. They are, therefore, not discussed further in this part of the document.

3.5.4 Alkali injection

This process uses the direct injection of one or more dry sorbents such as sodium bicarbonate into the flue-gas stream. Some tests have demonstrated the capability of alkali injection into the furnace, duct or spray dry scrubber for combined SO_2/NO_X reduction. The mechanism by which this occurs is not completely understood, but these processes can reduce NO_X significantly. Up to 90 % NO_X reduction has been achieved, depending on such factors as the ratio of SO_2 to NO_X in the flue-gas, reaction temperature, granulometry of sorbent, and residence time. A problem of alkali injection is that the higher NO_2 concentrations can give a brown-orange colouration to the flue-gas. Since this process is still in the demonstration stage it will not be discussed further in this document and no information on the general performance can be given.

3.5.5 Wet scrubber with additives to achieve NO_X removal

These processes are generally based on existing wet scrubbing techniques for the removal of SO_2 (limestone or lime slurries), with additives used to achieve NO_X removal. Additives such as Fe(II), EDTA and yellow phosphorus have been shown to achieve variable NO_X removal efficiencies at the laboratory or pilot plant scale. On a commercial scale, about 10 wet, combined SO_2/NO_X removal plants have been operated, with unit capacities of 10000 - 200000 m^3/h. These processes employ ClO_2 or O_3 as an oxidising agent, which is added to the gas, before it is subjected to sodium wet scrubbing to remove 30 – 80 % of NO_X and more than 90 % of the SO_2. In addition, more than 95 % of the mercury is removed by sodium scrubbing using NaClO as the additive. These processes are not suitable to treat large volumes of gas because of the high cost of the oxidising agent and the problems of disposing of waste water containing nitrite and nitrate. No information is available as to whether this process is actually applied to a large combustion plant. Therefore no information on the general performance can be given.

3.5.6 General performance of combined techniques for reducing SO_2 and NO_X

Technique	General SO_2/NO_X reduction rate	Other performance parameters		Remarks
		Parameter	Value	
Activated carbon process	98 %/60 – 80 %	Operating temperature	90 – 150 ºC	- the activated carbon process also has a considerable potential for removing SO_3 and air-toxic substances such as mercury and dioxins - waste water is only produced in small amounts from the operation of the pre-scrubber - several commercial systems have been installed, mainly in Japan - the process is capable of cleaning flue-gases from different fuel types such as coal and oil.
		Reagent	Activated carbon/ammonia	
		Reliability	98 %	
		Other substances removed	HCl, HF, dioxin	
		Energy consumption as % of electric capacity	1.2 – 3.3 %	
		By-products	Elemental sulphur, or sulphuric acid	
NOXSO process	97 %/70 % (anticipated)	Reagent	Alumina beads impregnated with sodium carbonate	- the NOXSO process is in the demonstration stage and is scheduled to be tested in a 108 MWe cyclone in the US under the US DOE CCT-3 programme [33, Ciemat, 2000].
		Reliability		
		Energy consumption as % of electric capacity	4 %	
WSA-SNOX process	95 %/95 %	Reagent	Ammonia	- very low particulate emissions (below 5 mg/m^3).
		Reliability		
		Energy consumption as % of electric capacity	0.2 %	
DESONOX process	95 %/95 %	Reagent	Ammonia	- waste water is generated by the use of a wet ESP for the removal of sulphuric acid aerosols - in theory, liquid SO_2, sulphuric acid and elemental sulphur are possible to produce but plants commissioned to date have only produced sulphuric acid.
		Reliability	96 – 98 %	
		Energy consumption as % of electric capacity	2.0 %	

Table 3.15: General performance of different sorbent injection techniques for reducing sulphur oxide/nitrogen oxides emissions

3.6 Techniques to reduce metal (heavy metal) emissions

Metals (commonly referred to as heavy metals) bound in most fossil fuels are liberated during combustion and may be released to the atmosphere on particles or as vapours. Metals which are of most concern with respect to fossil fuel utilisation are As, B, Cd, Cr, Cu, Hg, Mo, Ni, Pb, Se, V and Zn. Some of these metal elements are very toxic, especially if they are present in sufficient quantities.

Metals are partitioned into several output streams, mainly combustion residues such as fly ashes but also flue-gas, which enter downstream pollution control devices (Figure 3.36). Because of the large quantities of fuel consumed in energy generation, large amounts of potentially hazardous metals can be released into the environment. Most metal elements are associated with particulates. Volatile elements preferentially condense onto the surface of smaller particles in flue-gas streams because of the greater surface area. Hg is a highly toxic metal which escapes capture by flue-gas control devices and which occurs in some waste fractions being co-combusted in power plants but also in coals of low quality. Hg is emitted, to a large extent, gasously (see Figure 3.35).

The adequate method for obtaining data on emission values and on the behaviour of heavy metals during combustion and flue-gas cleaning is to establish a mass balance across the total combustion installation considered (Figure 3.36). Heavy metal mass balance investigations have been carried out for various types of large-scale hard coal- and lignite-fired power plants [127, Clarke and Sloss, 1992], [129, Maier, et al., 1992], [130, Rentz, et al., 1996], [131, Rentz and Martel, 1998].

Figure 3.36: Mass balance of heavy metals, fluoride and chloride in coal-fired combustion plants

Because volatile metal elements are enriched in the fine-grained particulate material carried downstream of the combustion chamber, the emission of these elements depends more on the efficiency of the gas cleaning system than upon the method of fuel conversion.

Several control technologies have been developed which are theoretically capable of removing a large portion of certain metals from flue-gas. These systems can generally be divided into two categories:

- techniques that are commonly used to remove particulates, SO_x or NO_X emissions
- techniques that have been developed expressly to remove trace elements from the flue-gas.

3.6.1 Control of mercury (Hg) emissions

3.6.1.1 Primary measures to reduce the Hg content of solid fuel

Fuel cleaning (mainly the cleaning of coal) is one option for removing mercury from the fuel prior to combustion. There are many types of cleaning processes, all based on the principle that coal is less dense than the pyritic sulphur, rock, clay, or other ash-producing impurities that are mixed or embedded in it. Mechanical devices using pulsating water or air currents can physically stratify and remove impurities. Centrifugal force is sometimes combined with water and air currents to aid in a further separation of coal from impurities. Another method is dense media washing, which uses heavy liquid solutions usually consisting of magnetite (finely ground particles of iron oxide) to separate coal from impurities. Smaller sized coal is sometimes cleaned using froth flotation. This technique differs from the others because it focuses less on gravity and more on chemical separation [168, US EPA, 1997].

3.6.1.2 Flue-gas treatment technologies to reduce mercury emissions

Most metals have sufficiently low vapour pressures at typical air pollution control device operating temperatures that condensation onto particulate matter is possible. Mercury, on the other hand, has a high vapour pressure at typical control device operating temperatures, and collection by particulate matter control devices is highly variable. The most important factors affecting mercury control on utility boilers include the flue-gas volume, flue-gas temperature and chloride content, the mercury concentration and the chemical form of the mercury being emitted. The chemical species of mercury emitted from utility boilers vary significantly from one plant to another. Removal effectiveness depends on the species of mercury present.

Factors that enhance mercury control are low temperatures in the control device system (less than 150 ºC), the presence of an effective mercury sorbent and the application of a method to collect the sorbent. In general, high levels of carbon in the fly ash enhance mercury sorption onto particulate matter, which is subsequently removed by the particulate matter control device. Additionally, the presence of hydrogen chloride (HCl) in the flue-gas stream can result in the formation of mercury chloride, which is readily adsorbed onto carbon-containing particulate matter. Conversely, sulphur dioxide (SO_2) in flue-gas can act as a reducing agent to convert oxidised mercury to elemental mercury, which is more difficult to collect.

Control technologies designed for controlling pollutants other than mercury (e.g. acid gases and particulate matter) vary in their mercury-removal capability, but generally can achieve reductions no greater than 50 % (except for high removal efficiencies for mercury chloride by wet scrubbers).

Carbon filter beds have been used successfully in Germany for mercury control on utility boilers and municipal waste incinerators. Injection of activated carbon into the flue-gas has been applied for a LCP co-combusting sewage sludge where mercury reductions of at least 85 per cent have been achieved. The addition of activated carbon to utility flue-gas for mercury control increase the amount of particulate matter requiring disposal [168, US EPA, 1997].

3.6.2 Reduction of metal emissions in particulate control systems

Electrostatic precipitators and fabric filters are commonly used to remove particulate matter from flue-gases generated by combustion plants burning solid or liquid fuels. These systems can operate with an overall efficiency of >99.9 %. However, the removal efficiency is generally lower in the smaller particle size range, i.e. the size range in which particles enriched with metal elements might be found.

Fabric filters have a similar overall particulate removal efficiency to ESPs (i.e. greater than 99.9 %) but are better at controlling fine particulate matter and less sensitive to particulate loading and fly ash characteristics. The collection efficiency may be increased further still by using flue-gas conditioning with small amounts of additives added to the gas flow upstream of the filters.

Some elements may remain in the gas phase until the flue-gases have cooled sufficiently for condensation to occur. By the time flue-gases encounter the fabric filter, they have cooled sufficiently to allow also some condensation of Hg, similar to cold-side ESP. Some estimates report that an average Hg removal efficiency of about 40 % can be achieved for power stations fitted with fabric filter systems. The Hg removal efficiency depends strongly on the fuel properties (e.g. Cl).

3.6.3 Reduction of metal emissions in FGD systems

Wet scrubber FGD systems are an effective method for reducing emissions of certain metals. This is mostly because the flue-gas temperature is reduced to about 50 – 60 ºC by passing through the absorber, which allows many of the more volatile metals to condense from the vapour phase, and allows them to be removed from the flue-gas. The condensed metals are then mainly transferred to the waste water from the wet FGD system.

Various studies have given removal efficiencies from the flue-gas of 30 – 50 % for Hg and 60 - 75 % for Se. However, the lime used in some systems may be an important source of As, Cd, Pb, and Zn, and so the concentrations of these elements can even increase downstream of the FGD. Emissions from the scrubber depend on the specific process and operating conditions.

An average Hg removal efficiency of 96.6 % was achieved for instance by adding sodium hypochlorite additives to the flue-gas from a waste incinerator in Japan. Sodium hypochlorite stabilises Hg in the flue-gas, allowing it to be captured in the scrubber water. The Hg can then be removed from the waste water stream using reduction, volatilisation, condensation and Hg separation processes.

The overall removal of Hg in various **spray dry systems** varies from about 35 – 85 %. Those systems configured with a particulate removal system before a spray dry scrubber, have high metal retention because a large proportion of these elements (including volatile species) are removed before the FGD unit. Highest particulate removal efficiencies, especially for fine particles, are achieved by spray dry systems fitted with downstream fabric filters. These systems may also be expected to achieve the highest metal removal efficiencies. Those plants fitted with particulate removal systems before the spray dry scrubber had Hg removal efficiencies up to 70 % already before entering the FGD unit.

Activated carbon technology has been applied in the US to increase Hg removal in spray dry scrubber/ESP systems. Tests indicate an increase in Hg removal efficiency from 27 to 78 % at an outlet temperature of 140 °C, and from 66 to 86 % at an outlet temperature of 110 °C. Similar improvements were also noted for spray dry scrubber/fabric filter systems, with an improvement in Hg removal from 69 % without additives to 91 – 95 % with additives. This technology is currently being used at a waste incinerator in Switzerland.

It is also possible to reduce Hg emissions using additives in other FGD systems, such as dry injection systems. With regard to the additive, Sorbalit may be added for instance. This is a sorbent that is composed of calcium hydroxide and various other organic and inorganic constituents.

3.6.4 Reduction of metal emissions in NO_X control systems

Low NO_X burners do not appear to influence the behaviour of metals during combustion. Metal emissions may increase in selective catalytic cleaning systems (SCR) which involve the addition of chemicals to flue-gases. However, most NO_X control systems appear to neither reduce nor increase metal emissions.

3.6.5 Reduction of metal emissions by systems designed for metal removal

Some systems have been developed expressly for the purpose of reducing certain metals from flue-gas streams, mostly to reduce emissions of Hg and other toxic metals (such as As, Cd, and Pb) from waste incinerators. These systems include selenium filters, activated carbon filters and various sorbents. They are only briefly discussed in this section.

Different sorbents such as silica, bauxite (alumina), kaolinite, emathlite, and lime have been investigated for their ability to remove metals from flue-gas. A detailed list of them and other possible sorbents can be found in [33, Ciemat, 2000] but note that some of the processes are of limited practical use for large power stations because of the low operating temperatures, harmful secondary effects and the high cost of some of the sorbents.

Activated carbon or coke filter systems have been developed which can be used to remove metals such as Cd, Hg, and Pb from flue-gases. Information can be found in [33, Ciemat, 2000] regarding a lignite coke filter and catalyst system which, in addition to acid gas removal, adsorbs metal elements. Tests carried out at a pilot scale system, fitted to a municipal waste incinerator, indicate that virtually all the Hg is removed from the flue-gases by the lignite coke material.

Experimental tests show that a reduction in the concentration of metallic Hg is obtained when activated carbon is added to the flue-gas stream. The carbon collected downstream in a fabric filter contained 40 – 60 ppm Hg, which corresponded to between 13 and 20 % of the Hg in the flue-gas.

The removal of Hg vapour from flue-gases using **sulphur-impregnated adsorbents** has been studied using packed beds. The experimental results have shown that the impregnation of active alumina and zeolite by sulphur increases the adsorption capacity, by several orders of magnitude. Although the sorbents have a high Hg adsorption capacity, they are unable to remove all the Hg (as they already have an outlet concentration greater than zero for gases passing through the filters, even at the beginning of gas breakthrough). Very low Hg concentrations in the flue-gases may be achieved using a bed of sulphur-impregnated active alumina and zeolite adsorbents followed by a second bed of sulphur-impregnated active carbon adsorbents.

A system is available for Hg removal that uses a **selenium impregnated filter** which may be retrofitted to existing exhaust ducting after scrubbers. The filter relies on the strong affinity of Hg to Se, with which it combines to form mercury selenide (HgSe), a highly stable compound. Spent filters are returned to the manufacturer for recharging.

In future, these new systems for removing metal elements could be an important method of reducing metal emissions. However, at present most processes are not at an commercial stage or seem more appropriate for controlling emissions from waste incinerators. Additional research is required to assess the application of such systems to large combustion plants.

3.7 Techniques to reduce emissions of CO and unburned hydrocarbons

The emissions of unburned gases, which can be divided into two main groups: carbon monoxide (CO) and hydrocarbons (C_xH_y), can be reduced by advanced combustion techniques. Emissions of CO and unburned hydrocarbons are a consequence of incomplete combustion and can be caused by too low combustion temperatures; too short a residence time in the combustion zone; or by an inefficient mixing of the fuel and combustion air, leading to local areas of oxygen deficiency.

Carbon monoxide is the most important unburned gas. It is a stable compound even at high temperatures if there is no oxygen present. Hydrocarbons, on the contrary, can be decomposed and form soot at high temperatures in an oxygen-poor atmosphere. In general, it can be said that emissions of unburned hydrocarbons may be generated when a low combustion zone temperature and inefficient mixing of fuel and air occur together. However, such conditions are rare in large modern furnaces.

Generally, CO emissions can be kept under 50 mg/Nm^3 if the combustion is well controlled. Hydrocarbon emissions in modern power plant boilers are negligible, typically below 5 mg/Nm^3. Techniques and figures that are specific for emissions from gas turbines and reciprocating engines are described in the fuel specific chapters (liquid/gaseous).

Emission of unburned gases are affected by several parameters. Typically, the emissions of unburned gases are highest, when there are problems in controlling the fuel/air ratio in the furnace or when the fuel quality is not homogenous (as is the case with waste or biomass). Coals with low reactivity and volatile content (anthracites) tend to increase emissions of unburned gases. Higher emissions can also be a consequence of a low combustion temperatures, caused by using a low-rank fuel, partial loading or through malfunction of the burner.

Some measures to reduce NO_X emissions, such as combustion with lower excess air or strong air staging, can increase emissions of the unburned gases. In these cases, the importance of assuring an efficient mixing of air and fuel in the combustion system must be emphasised. NO_X reduction with the SNCR method can also cause higher CO emissions. CO emissions can be decreased, when limestone feeding is increased in the fluidised bed combustion boilers.

Similarly to the costs of NO_X reduction, it is impossible to separate the cost of these measures from the total investment. If there are problems with unburned gases in an existing power plant, the case has to be assessed separately, and the possible expenses clearly set out in a feasibility evaluation.

3.8 Techniques to reduce halogen emissions

Natural sources, the sea in particular, are the major source of chlorine, bromine and iodine in the atmosphere. Human activities, especially industrial sources such as aluminium manufacture, are the major global source of fluorine emissions. In many countries, the combustion of fossil fuels is the largest source of chlorine (as HCl) from human activities and may also be a predominant source of fluorine (as HF). Emissions of halogens from combustion are in the form of highly soluble acidic gases which can contribute to acid rain.

The emission of halogens depends on a number of factors – the initial halogen content of the fuel and the form in which they are present, the combustion conditions (temperature, residence time, etc.), and on the use of various pollution control technologies. Those technologies and processes designed, for instance, to control emissions of SO_X, such as limestone addition to the boiler and FGD, can be especially effective in reducing emissions of the acidic halogen gases. With rotating gas heat exchangers, HF bypasses FGD systems to ~50 %.

This section discusses the halogen removal efficiency of the various pollution control technologies most commonly installed in LCPs (i.e. particulates and sulphur control equipment).

3.8.1 Reduction of halogen emissions in particulate control systems

Very little information is available regarding the capture of halogens by electrostatic precipitators (ESP) and baghouses (fabric filters). Considering the nature of the gases, however, in the absence of a sorbent it is likely that they have little or no effect. The addition of a sorbent such as lime to the combustion zone can result in the capture of halogens on or in particles which may be trapped by filtration systems. With dry sorbent injection in the furnace, HCl reduction is limited as SO_2 reduction releases HCl from sorbent at high temperatures.

3.8.2 Reduction of halogen emissions in FGD systems

In wet FGD systems, flue-gases are initially washed in a pre-scrubber, which stops the potential build-up of chlorides in the FGD absorber circulation loop. In the pre-scrubber, most of the fly ash and soluble gases such as HCl and HF are captured and the effluent is removed to a waste water treatment plant.

The actual removal efficiency of halogen emissions from combustion plants using a wet FGD system varies greatly. Chlorine (HCl) removal efficiency ranges from 87 to 97 %, fluorine (HF) from 43 to 97 %, bromine from 85 to 96 % and iodine from 41 to 97 %.

A common dry FGD system for both utility and industrial boilers is the spray dryer. The flue-gas comes into contact with an atomised lime slurry or sodium carbonate solution. The hot flue-gases dry the droplets and precipitates the dissolved chemicals, which can then be collected along with any remaining boiler fly ash in a baghouse or ESP. According to [33, Ciemat, 2000] chlorine and fluorine removal efficiencies in dry FGDs are equivalent to those from wet FGDs.

3.8.3 Reduction of halogen emissions in NO_X control systems

SCR and SNCR are technologies designed to remove NO_X from flue-gases. In SNCR the ammonia used to reduce NO_X can react with HCl in the fly ash to produce ammonium chloride. It may be assumed that if ESP or other particulate controls are in place, the ammonia may still react with any HCl in the flue-gas, although this effectively neutralises the acidity of the HCl. Ammonium chloride in plumes can lead to problems of visible plumes.

3.9 Reduction of greenhouse gas emissions from large combustion plants

Various methods, processes and technologies to reduce greenhouse gas emissions from fossil fuel-fired combustion plants, especially for the reduction of CO_2 emissions, have been discussed in recent years. This section briefly reviews available measures, noting those that can currently be applied to conventional power plants. There are two main options to reduce greenhouse gas emissions from large combustion plants. The first option is to avoid emissions of CO_2 by improving the efficiency of a combustion process, energy use and conservation. The second option is to control CO_2 emissions by flue-gas separation and disposal, which is still in a very early development stage and has not yet been applied to LCPs.

3.9.1 Reduction of carbon dioxide emissions by increasing the thermal efficiency

Technologies to improve the thermal efficiency of a combustion installation are currently being developed for economic and environmental reasons, including reducing greenhouse gas emissions. These include improvements to conventional power generating technologies as well as more advanced and novel technologies such as gas turbine combined cycles (GTCC). As a result of technological progress, there has been a constant improvement in the efficiency of power generation technologies as shown in Figure 3.37.

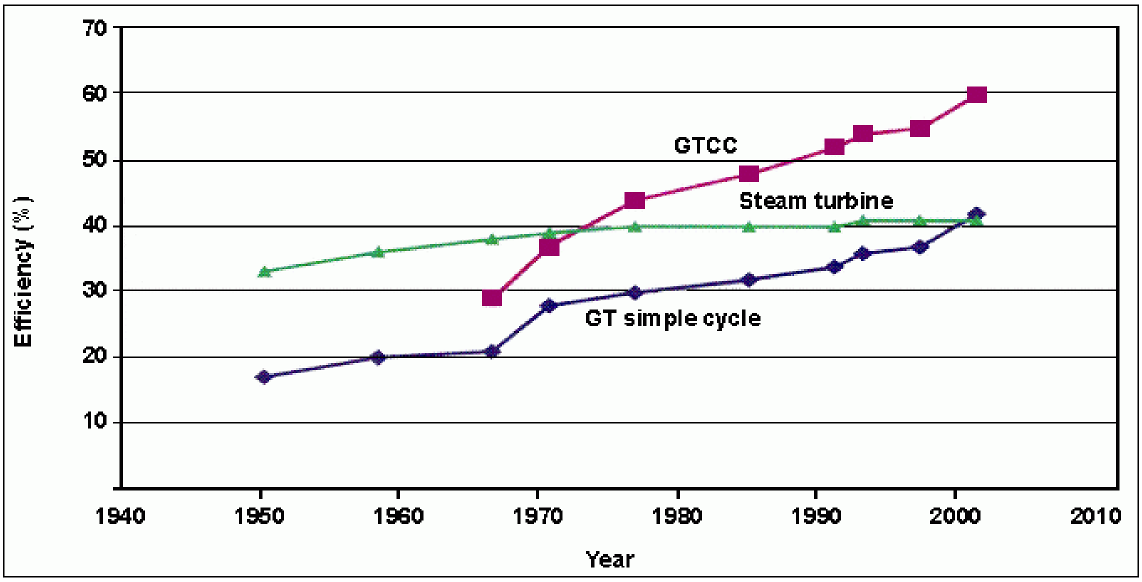

Figure 3.37: Efficiency improvements of energy generating technologies over the past 50 years [105, Steen, 2001]

The relationship between efficiency and CO_2 releases for different power generation systems is shown in Figure 3.38. The vertical position of the curves corresponding to the different fuels used in large combustion plants and reflects their carbon content. From the slope of the tangent to the curves, the reduction in CO_2 releases per efficiency increment can be estimated. As a rule of thumb, an efficiency increase from 40 to 41 % for a gas-fired power plant reduces emissions of CO_2 by 2.5 %. For a 500 MW plant with a load factor of 85 %, this translates into a decrease of CO_2 emissions of 37000 t/yr[4].

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[4] 500 MW x (0.85 x 365 x 24h/yr) x 400 kg/MWh x 2.5 % = 3.7 10^7 kg/yr.

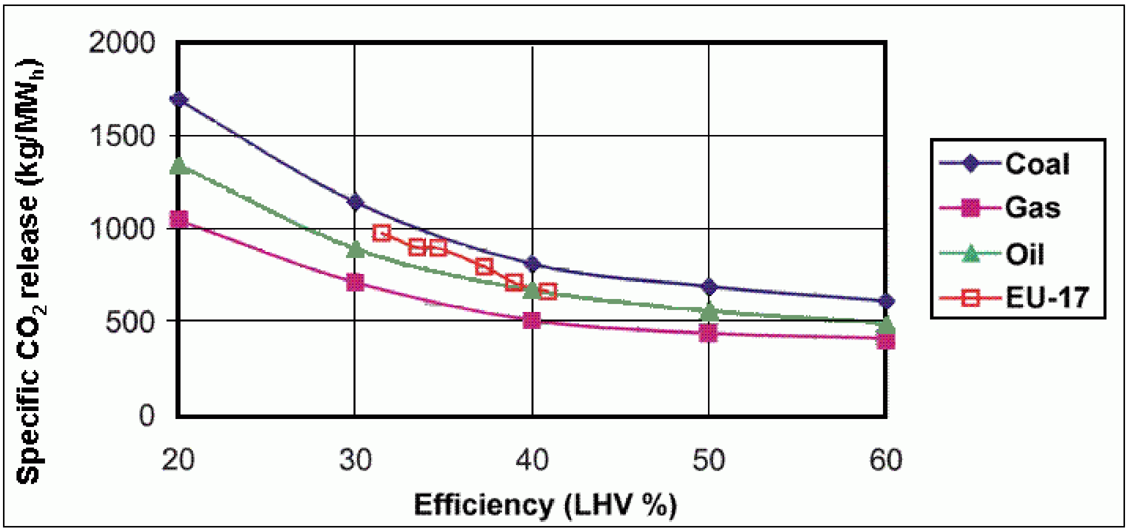

Figure 3.38: CO_2 release versus efficiency
[105, Steen, 2001]

Figure 3.38 indicates the trends in overall CO_2 emissions and the average efficiencies for thermal power generation in the EU-17 (EU-15 + Norway and Switzerland) over the period 1970 – 1996 (measured data) and projections for 2000 – 2010 (last two points). The data clearly demonstrates that as thermal power generation efficiency has increased, CO_2 emissions have decreased.

The dependence of the thermal efficiency on the power plant size, as shown in Figure 3.39, suggests that CO_2 emissions do not depend on plant size.

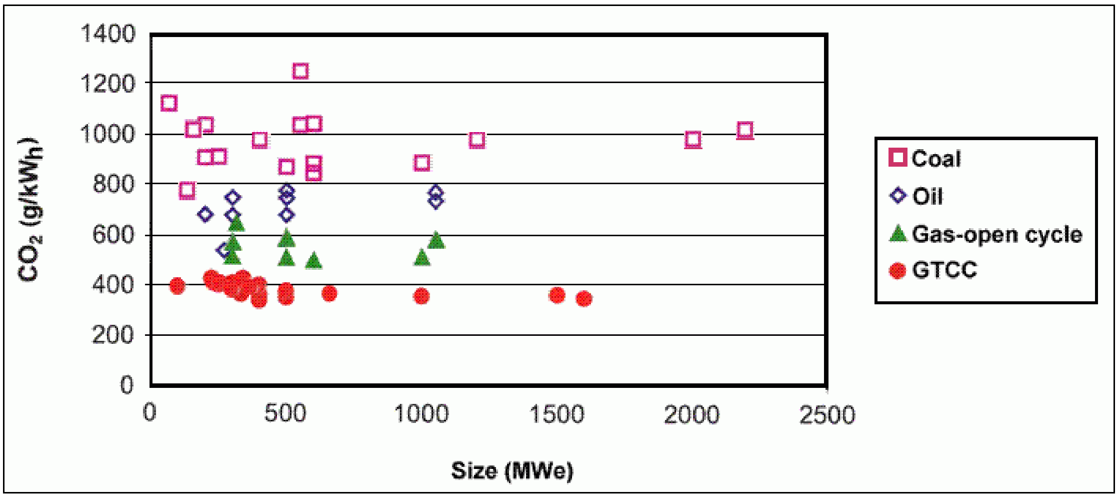

Figure 3.39: Specific CO_2 emissions versus plant size
[105, Steen, 2001]

To demonstrate the current performance, Figure 3.40 ranks the different power generation technologies in terms of their specific CO_2 emissions. The two points for each technique in the figure refer to the maximum and minimum values quoted in literature [105, Steen, 2001].

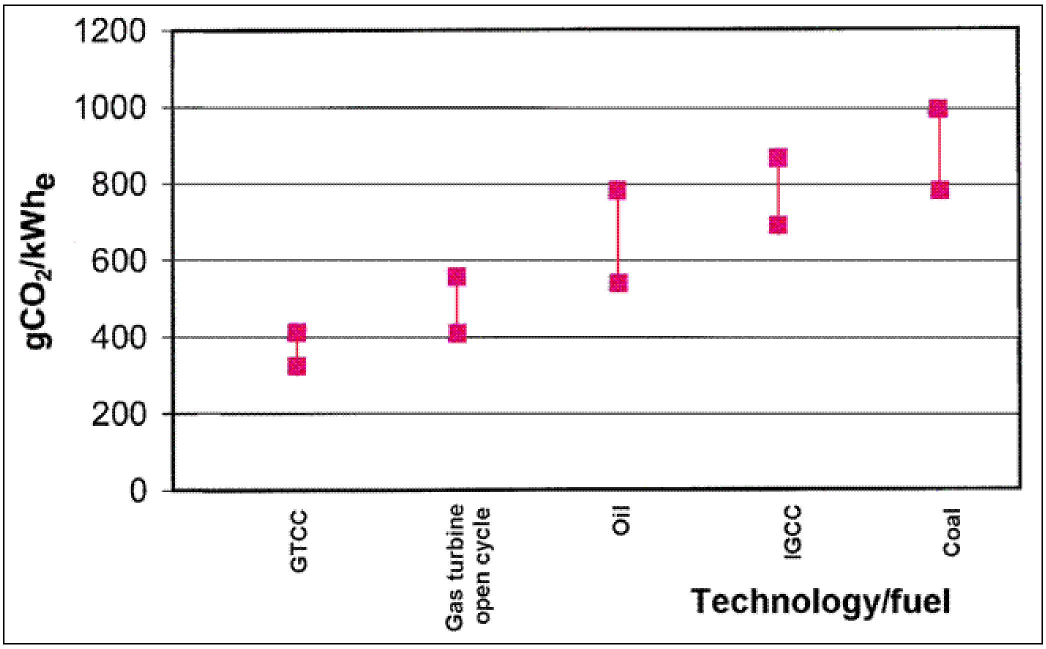

Figure 3.40: CO_2 emission performance of current technologies
[105, Steen, 2001]

To increase the efficiency of electricity and heat generation, the first option is to replace or further optimise the main process items such as turbines, pumps and pollution control systems. Further measures to increase conventional power plant efficiency include lowering the condenser pressure, optimisation of the feed-water preheat system, utilisation of waste heat and the use of supercritical steam cycle conditions.

The pursuit of even higher efficiencies and growing concern about the environmental impact of power generation have led to several new technologies, e.g. integrated gasification combined cycle power plants and pressurised pulverised coal firing technology. These technologies can achieve efficiencies well above those of the current technology and have considerably lower emissions, but they are not at a mature state of development yet.

The combined generation of electricity and heat (CHP) using so-called co-generation plants, represents another possibility to increase the efficiency of the used fuel. Within co-generation plants, energy consumption can be reduced by up to 50 % compared to the separate generation of electricity and heat. Co-generation plants can be built as large combustion plants with a capacity of several hundred MW, but also as small commercial, institutional and agricultural facilities. Reasonable and cost-effective use of this technology is feasible when heat can be supplied to a district heating network or to a nearby industrial plant where it is used for process heating purposes [32, Rentz, et al., 1999].

3.9.2 Removal of carbon dioxide from flue-gases

Given current technology, increasing the thermal efficiency of energy-generating processes and techniques is the most important measure in reducing the amount of greenhouse gases emitted per unit of energy produced. Efficiency increases are, however, limited by various factors so that, even with an increased efficiency, significant amounts of CO_2 will still be emitted. To reduce the emissions of CO_2 further, different technical options are currently under development or at a research stage. These technical options for CO_2 capture and disposal are not yet applied to large combustion plants, but they might be available in the future. The currently discussed technical options to capture CO_2 are well described by the IEA (International Energy Agency) [41, IEA, 1992] and are briefly presented in Annex 10.2 of the document.

3.10 Techniques to control releases to water

Section 1.3.3 gives an overview of the different sources of waste water that can be found in a large combustion plant. The waste water encountered in power plants is composed of polluted water arising from the various LCP processes and rainwater from the site. This water has to be treated in waste water treatment plants, where a reduction of pollutant concentrations is achieved. The following section reflects the techniques that are normally used to treat the contaminated waste water streams before they can be discharged to the aquatic environment.

The amount and the quality of the waste water and, correspondingly, the configuration of the waste water treatment plant which is appropriate for the needs of a particular LCP's effluents, is site-specific and depends on many parameters, including the:

- type and composition of fuel
- type of storage facilities for fuel and chemicals
- type of fuel preparation
- type of combustion processes
- type of cooling systems
- type of chemical conditioning applied for boiler water and cooling water
- quality of raw water available
- type of water treatment systems
- type of flue-gas treatment systems
- nature of combustion by-products (fly ash, wet ash, FGD gypsum, etc.) and their
- management practices (disposal, sale).

The individual waste water streams generated by the various operations in an LCP include:

- process waste water in particular waste water from the FGD unit
- collected rainwater run-off and fire fighting water
- sanitary waste water

Due to different composition and quality (pollutants character and concentration), the above-mentioned streams are usually collected by separate drainage systems and are directed to separate destinations for further treatment in dedicated waste water treatment plants (sanitary waste water in biological waste water treatment plants, process waste waters and contaminated rainwater run-off in industrial waste water treatment plants).

It becomes obvious that the design of the drainage systems is very important on the LCP site, as by employing well designed drainage systems, the waste water management is optimised, achieving economies in water consumption and the design and operation of the waste water treatment plant.

Waste water is designed to flow, as far as possible, by gravity through the drainage systems to the various components of the waste water treatment plant, in order to avoid intermediate pumping and associated energy consumption.

Waste water streams vary greatly in flowrates and are encountered either continuously or periodically. Depending on their origin, the waste water streams contain different substances:

- solid substances (e.g. suspended solids)
- fluid substances (e.g. oils, oil-water emulsions)
- water soluble substances (organic, inorganic).

The waste water streams encountered most often in an LCP are listed below:

- waste water from water treatment plants
- waste water from the cooling circuit systems
- waste water from other origins in steam generation process
- waste water from flue-gas cleaning systems
- sanitary waste water.

3.10.1 Waste water from water treatment plants

Typically, water is pretreated before use in different areas of the LCP plant. The type of pretreatments carried out are softening and demineralisation. These pretreatments typically generate the following waste waters:

From softening plants:

- spray water from belt strainers (cleaning of surface water)
- filtrate from sludge draining (without chemical additions)
- filtrate from sludge draining (after flocculation and precipitation)
- back flushing water from sand filters.

The waste waters arising from various parts of the softening plant are usually recycled back into the process.

From demineralisation plants:

- ion exchange (resins) regeneration effluents.

3.10.2 Waste water from cooling circuit systems

These mainly include the blowdown of wet cooling towers and the occasional drainage from the evacuation of cooling towers basin. In once-through cooling systems inlet filter screen washings, cooling water discharge temperatures and the concentration of biocides or other additives must be considered.

Emissions from all types of cooling systems, including LCPs, to the environment, are dealt with in detail in the Industrial Cooling Systems BREF and are not included in the scope of this LCP BREF.

3.10.3 Waste water from other origins of steam generation processes

- blowdowns from drum-type steam generators
- laboratory waste water and sampling
- discharges from the water-steam cycle
- discharges from district heating systems
- condensate polishing plant regeneration effluents
- ash and slag handling and removal systems effluents
- boiler chemical cleaning effluents
- boiler wet conservation effluents
- washings of steam generators, air heaters, gas heaters, ESPs, DENOX, FGD plants and various other equipment
- oily effluents (dewatering of fuel oil storage and daily tanks, run-off from heavy fuel oil and/or diesel oil treatment systems, turbine or diesel engine houses, transformer areas, etc.).

3.10.4 Waste water from flue-gas cleaning systems

All wet-type flue-gas cleaning systems produce waste water that, due to the fuel and materials used, contain heavy metals among other components. One of the main sources of waste water in this context is the wet limestone scrubber that is used in a large number of power plants for desulphurisation of the flue-gas, although this can be reduced by using fuels with a lower chlorine content. This results in a reduction in the purge to the waste water treatment plant, which in turn reduces emissions to water. An example of a conventional waste water treatment system is presented in Figure 3.41, but it should be noted that there are many different types of systems, depending on the different national regulations and site-specific factors.

The pH value of FGD waste water must be increased in order to precipitate heavy metals. This is generally achieved using either lime milk or caustic soda, causing the formation of metal hydroxides. By adding flocculents (iron(III)chloride), flakes are formed. The addition of coagulation aids (polyelectrolyte), allows the agglomeration of individual flakes, so that a greater flake formation ensues. The sludge is then pre-sedimented, drained and disposed of or co-combusted in case of slag tap combustion. Part of the ‘thin’ sludge is recycled to the flocculation stage where the sludge particles serve as initial crystallisation nuclei promoting more rapid flocculation.

The treated waste water from the pre-sedimentation stage can be supplied to a baffle plate thickener for further sedimentation. The suspended micro-particles deposit on the inclined baffle plates. The sludge falling off the plates is gathered at the lower point of the baffle plate thickener and can also be recycled. The cleaned waste water is fed to the drain via the overflow of the baffle plate thickener, provided the regulatory limit values are met. In addition, the pH value is not permitted to exceed the range of 6 to 9.5, otherwise the water must be neutralised. If ammonia is present in the waste water it is first fed to an ammonia stripping plant before it is discharged to the drains. In some processes, e.g. with higher input of Hg because of co-combustion of wastes, it is customary to add also organic sulphide (TMT 15) after addition of lime milk, precipitating heavy metals as sulphides, which is more effective than using the hydroxide. The disadvantages, that the heavy metal sulphides (greater quantities) need to be disposed of, because by co-combustion of these residues, the sulphur is released as sulphur dioxide and Hg is released again.

Various plants treat FGD waste waters differently. Thus some companies use, e.g. flocculents and flocculation aids, others use only flocculation auxiliaries and organic sulphide. There are, however, also operators who use flocculents, flocculation auxiliaries and organic sulphide.

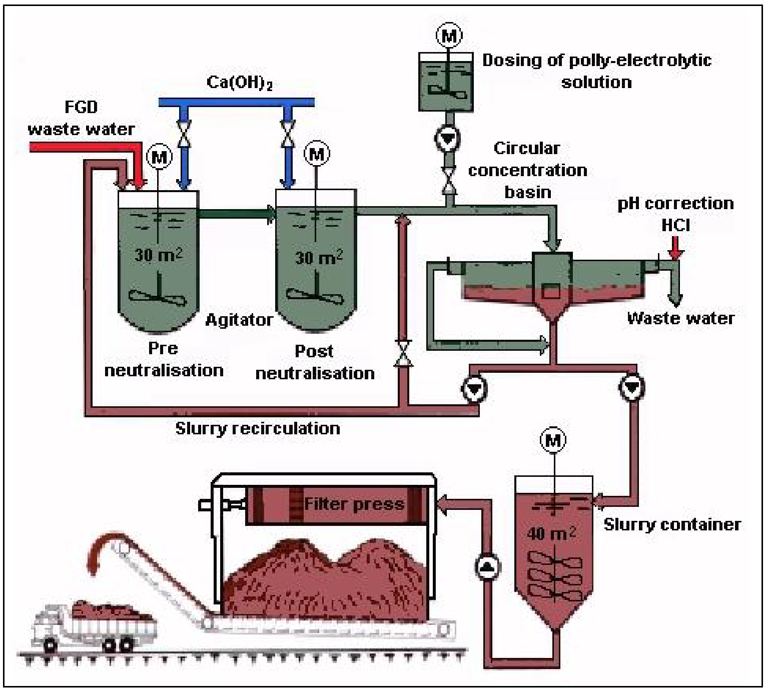

Figure 3.41: FGD waste water treatment plant
[58, Eurelectric, 2001]

An example of an FGD waste water treatment plant is shown in Figure 3.40. FGD waste water is pre-neutralised in an agitator with the aid of lime slurry. The pH is further increased by additional dosing of lime slurry in the second reactor. Initial flocculation and settling of heavy metal hydroxides occurs in the circular concentration reactor tank. Polyelectrolytic solution is fed into the supply line to the concentration reactor tank in order to avoid repulsion between hydroxide particles and to accelerate sedimentation.

The treated water, with a pH of 6 to 9, may be transferred from the upper quiet zone of the circular concentration reactor tank to the main water inlet. If the pH is above 9, it is corrected with an acid additive, e.g. hydrochloric acid. Part of the slurry withdrawn from the concentration tank is fed as contact slurry to support flocculation in the first agitator. This slurry acts as an accelerator for the precipitation of the hydroxides. Most of the slurry from the agitator is temporarily stored in a slurry container, dewatered in a filter press and finally stored in a bunker prior to disposal.

3.10.5 Sanitary waste water

This includes special waste waters originating form toilets and canteens. Current emission levels are usually estimated at approximately 75 l/person/day. Emissions are characterised by high organic content.

It is noted that waste oils (lubricating or working oils) are considered as solid wastes and they are usually gathered separately and disposed off-site by an authorised contractor for further management (e.g. incineration, regeneration, etc.).

3.10.6 Waste water treatment techniques

In order to decide which are the best waste water management and treatment practices for a specific LCP, a thorough assessment of the expected waste water streams has to be carried out. The waste water must be characterised regarding the nature and concentrations of the pollutants and the pattern of the expected flows from the various sources. Following that, a decision has to be taken as to the configuration of the most appropriate waste water treatment plant for each specific case.

The removal of polluting substances from the waste water prior to discharge to the environment is effected by the application of the appropriate combination of a wide range of physical, chemical and biochemical processes, including:

- filtration
- pH correction/neutralisation
- coagulation/flocculation/precipitation
- sedimentation/filtration/flotation
- dissolved hydrocarbon treatment
- oil-water separation systems
- biological treatment.

The selection of the appropriate treatment and/or management technique depends on the main quality characteristics and volume of the waste water and required quality standards for the receiving waters for the treated effluents.

Thus, effluents containing high amounts of suspended solids, present in LCPs burning solid fuels (ash handling and removal system, slag extraction and removal system, boiler and air preheaters washing, open fuel storage areas, etc.), are normally subjected to a primary settling stage for the removal of heavier suspended solids. This is followed by flocculation, with coagulant and organic polymer dosing aided by pH adjustment, before final settling and removal of the sludge. A final pH adjustment of the treated effluent may be required before discharge to the receiving water.

Acid or alkali effluents (e.g. ion exchangers regeneration effluents, boiler cleaning chemicals, boiler blowdown, etc.) need to be neutralised before discharge. Oily effluents arising from the fuel oil treatment systems, leakage or dewatering of fuel oil storage facilities, unloading stations, transformer area, etc., may contain high amounts of oil, which can be re-used. Therefore, a primary oil separation stage is needed for the collection of these oils, normally carried out in gravity separation tanks equipped with oil retention baffles.

The residual waste waters, which may still contain small amounts of oil in oil – water emulsion form, are treated in API or lamella separators equipped with oil skimmers or using air flotation. Sanitary waste water may be treated in a municipal sewerage system, if one is available. Otherwise, they may be either discharged to a septic tank where small number of personnel are employed or treated in an on-site biological unit, normally of the extended aeration activated sludge type.

In certain cases, instead of being treated in the LCP waste treatment plant along with other effluents, special waste waters (e.g. water containing hydrocarbons used for analysis in the laboratory) are collected separately and disposed of offsite by an authorised contractor. The management of the firewater, which occurs only in emergency situations, depends on the location of the fire. Such waters are collected by the drainage systems corresponding to the fire location, retained in firewater retention ponds and treated, if necessary, before discharge. Effluents from LCPs may be treated either separately by stream, or using combined treatment techniques. Examples are given below.

The issue of the water and waste water management is very important within an LCP. By optimising the recycling of the various intermediate discharges in the plant, a significant reduction in overall water consumption can be achieved, as well as minimising the final liquid effluent quantities that require further treatment.

For example, in several cases it is possible to collect all waste water from the various discharge points of the FGD plant and to reintroduce them into the process (scrubber) thereby practically avoiding any FGD effluents. In addition, various waste water streams may be used for fly ash humidification instead of service or raw water. Clean waste water downstream of the waste water treatment plant is usually collected in retention ponds to supply water to points of consumption where the water quality demand is adequate, e.g. limestone slurry preparation for FGD or for FGD gypsum and fly ash mixture stabilisation prior to disposal in a landfill.

3.10.7 Other waste waters

Surface run-off water arises from the contamination of rainwater that is collected from building roofs, paved areas and fuel storage (e.g. coal stoke piles). Contamination of rainwater occurs when materials such as dust (coal particulates) from fuel storage, surface deposition, etc. or oils are washed into the drainage system. The contamination of surface water can be prevented or minimised by the use of sedimentation basins, good practice in the storage of fuel and other raw materials, as well as by good maintenance, and cleaning of the whole plant.

Surface run-off may be collected separately. After a sedimentation step or chemical treatment it can be re-used for other purposes in the production process, for instance for water sprays to prevent dust formation from the storage of solid fuels.

In combustion plants, there are many other sources of waste water. Examples are: liquid effluents from cleaning stations for trucks delivering fuel (e.g. trucks transporting peat) and other raw material; sealing water from pumps; general operations, including the cleaning of equipment, floors, etc. These liquid effluents are normally collected and treated. Water from the sanitary system is normally discharged to the public sewerage system.

To reduce the concentration of water pollutants, end-of-pipe techniques such as neutralisation, flocculation, sedimentation and filtration may be used. These techniques are normally used together in a final or central on-site waste water treatment plant.

3.11 Techniques to control releases to soils

Where sludges and solid residues from waste gas and waste water cleaning in LCPs cannot be utilised, or whenever the current production exceeds demand, the surplus has to be disposed of in an environmentally responsible and sound way (e.g. by applying the results of the Environmental Impact Assessment (EIA) studies conducted). Acting in this way, the appropriate choice of site, disposal method and monitoring ensures that this surplus can be deposited without detriment to the environment. In common with other powdered materials, guidelines for the manipulation (including transport) of ash ensure the efficient protection against accidental exposure to dust. The aim is always to obtain by-products from the residues that can be used in other industrial sectors, for example as building material. Over recent decades, this aim has increasingly been met across the EU: in 1998, the utilisation rate of the various by-products was 89 % including use for reclamation of land and quarries.

The sludges, residues and by-products from LCPs can be subdivided into sludge from water and waste water treatment and residues and by-products from flue-gas desulphurisation and flue-gas dust precipitation. This is also screened matter from surface waters that is encountered at the rakes and screening facilities for the drawing-off of water.

The organic matter collected at the cooling water intake can be used as an energy source or composted and used afterwards to improve soil quality. Residual matter must be deposited. Sludge from treatment of waste waters from FGD plants can possibly be re-used as reaction agents in the FGD plant, due to the calcium components. They are also used as additives in coal-fired plant combustion to improve the ash melting behaviour. A high percentage of these sludges consists of gypsum. Therefore, they are partly also used in the gypsum industry and as setting retarder for cement in the cement industry. Non-usable sludges are deposited to landfill.

Sludge from the treatment of raw waters, such as surface water, is decarbonised and thus has a high content of calcium carbonate (e.g. 30 % or more). Besides the above-mentioned implementation in flue-gas desulphurisation and as an additive in coal boilers or other areas where calcium additives are used, these sludges can be useful as calcium fertiliser and for soil improvement in agriculture.

Residues and by-products from flue-gas desulphurisation, such as FGD gypsum (gypsum from flue-gas desulphurisation plants) and ammonium sulphates contain calcium and sulphur, which are used for fertilisation and in soil improvers in agriculture among other things. It is possible to use them in a targeted way, i.e. at precisely the spot where they are needed, rather than spreading them in an uncontrolled manner via the air to the environment and especially to the soil. Only 0.1 % of residues from SDA are currently used as fertiliser (see data from ECOBA); factors opposing the use of this kind of residue as fertiliser are the content of heavy metals (e.g. Cd, Hg) and the scepticism of farmers towards using this kind of residue. SDA products are also used specifically as a filler underground to stabilise e.g. underground mines. Other desulphurisation products such as sulphur or sulphuric acid are only produced in small quantities and are exclusively used in the chemical industry.

Residues and by-products from flue-gas dust removal are typically ashes, such as boiler slag from wet bottom furnaces; bottom ash from dry bottom furnaces; and fly ash from hard coal-fired and lignite-fired power plants. In fact, the utilisation of coal ash, as a replacement for minerals or manufactured products, saves the extraction of raw materials, while preserving and conserving natural resources, as well as reducing energy consumption and the emission of carbon dioxide (to the extent that one tonne of fly ash replacing cement saves approximately one tonne of CO_2).

Owing to its good filtering properties, about 60 % of the boiler slag is used in road construction and other surfacing and landscaping work. About 70 % of fly ash is used in the manufacture of cement, concrete and concrete products, in which it is valued for its building properties. It is also used in the production of mortar, bricks, masonry blocks, paving and mining mortar.

Ashes from lignite-fired power plants are mostly used as a leach-free stabiliser mixed with waste water from FGD plants for the filling of exhausted open-pit mines. Part of the ash is used for recultivation and surface covering. Certain qualities of lignite fly ash can be used in concrete manufacture. There are also many other possible uses for ashes and for ashes from fluidised bed combustion power plants.

In summary, it can be said that techniques to control releases to soil cover techniques of waste gas and waste water cleaning as well as techniques for residue and by-product utilisation, which result in a reduction in the amounts of waste that would otherwise have to be disposed of in landfills. With the increasing degree of the utilisation, the quantity of waste that has to be disposed of is reduced, which means the consumption of landfill volume becomes lower. The utilisation of by-products thus may serves the soil protection and conserves resources. However, care should be taken on critical parameters which have to be observed and these are e.g. long term leaching behaviour, stability of residues and monitoring and reporting of the quality of the residues. Therefore, unavoidable and non-utilisable mineral residual waste must still be disposed of to landfill.

3.12 Measures to control noise emissions

3.12.1 Basic options

The basic options to reduce noise are to modify the noise source, to change the transmission path of the noise or to make changes affecting the receiver. The first step that needs to be taken in any noise assessment is to identify the principal sources and paths of noise. Simple experiments like turning off machines are often effective in determining the dominant reasons for noise problems. If personal ear defenders and enclosures are excluded, an effective method to decrease the level of noise is to increase the distance between the receiver and the source. Basic noise calculation equations suggest that increasing the distance from the source decreases the noise by 20 dB for every ten-fold increase in distance. Optimising the location of noisy equipment and of the whole plant is, therefore, perhaps the most cost effective means of avoiding noise problems. This distance dependency is also used in the other so-called passive methods applied in industry.

The most straightforward method to remedy noise effects is to modify the mechanism of the source that produces the noise. Another alternative is to place the noise source in an enclosure. For an outside observer, the noise source would then be the volume surrounded by an enclosure. Acoustic barriers are commonly used to modify the sound path by increasing the distance that the sound waves have to travel from the source to the receiver. The use of noise absorptive material, particularly on the walls and ceiling, is an effective method to decrease reflection or reverberation inside the building. If the internal surfaces of the room are totally reflective, the noise approaches infinity theoretically. That is why environmental noise levels are, in some cases, controlled by adding absorptive material inside the building. An equipment-specific method to influence noise is the use of mufflers; typically these are used in channels or pipes.

Some common noise abatement techniques are:

- the use of embankments to screen the source of noise
- the enclosure of noisy plant or components in sound absorbing structures
- the use of anti-vibration supports and interconnections for equipment
- the orientation and location of noise-emitting machinery and the change of the frequency of the sound.

3.12.2 Structure-borne noise

Rotating machines such as turbines, generators, pumps, compressors end electric motors are the main sources of vibration and noise in power plants. The noise is often caused by machine vibration, which creates structure-borne noise. An effective method to limit the spreading of structure-borne noise is the use of machine foundations supported by vibration isolators. The principle of isolators is that the natural frequency of the system resting on the isolators is much lower than the principal running frequency of the machine. The isolated system balances the excitation force by inertia effect. The greater the mass on isolators, the smaller the vibrations of the system are, but in any case, the isolators considerably decrease the vibrations going through them to the surrounding structures. If the machine is on an isolated foundation, the connections from the machine have to be flexible. This effectively prevents the spreading of structure-borne noise to the channels and piping. The isolators supporting the foundations of large machines are usually helical steel springs. Rubber elements or bellows are also commonly used for isolation purposes.

3.12.3 Duct and piping noise

These systems should be designed for smooth uniform fluid flow. Sudden changes in geometry increase noise that strongly depends on the flow velocity. In some cases, the noise is even proportional to the fluid velocity, and the most effective method to reduce the noise is thus to decrease the local fluid velocity. One practical method for doing this is to provide piping with flexible internally damped supports. The use of a large bending radius is also beneficial. Piping noise is of two characteristic types: noise with a broad frequency band and noise concentrated at discrete frequencies. Pumps, fans and blowers produce noise at their running frequencies and their blade frequencies. The latter type depend on the number of blades around the impeller. These discrete frequencies can be affected by modifying the machine, for example, by minimising the rotor mass imbalance. In valves, the broadband noise usually relates to the pressure drop, and noise can be reduced by arranging for the pressure drop to occur in several stages. The use of mufflers or silencers, increased pipe-wall thickness and the lining of piping with an absorptive or isolating material are common solutions to noise problems at existing power plants.

3.12.4 Mufflers

There are different types of mufflers. For noise reduction in blowing lines and safety valves mufflers are used according to the ‘trottling principle’. Absorptive mufflers are suitable for reducing noise that covers a wide frequency band. Typical examples are a lined duct, a silencer consisting of parallel lined plates or a lined pressure chamber. Reactive mufflers are mainly based on the geometry of the muffler. These mufflers are effective only at specific frequencies or over a narrow frequency band. Simple expansion chambers or cavity resonators are typical examples of reactive mufflers. The air in the cavity forms a spring that affects the airflow directed through a neck to the cavity. The airflow acts as a mass producing a low frequency tuning effect in a very limited frequency band. Commercial mufflers are often combinations of the absorptive and the reactive types.

3.12.5 Machinery noise

During machine operation, minor deviations from the theoretical optimum can often generate noise. Examples of this are misalignment, mass imbalance or rotor eccentricity, which are always present to some extent. Thus, an unusual increase in noise may also be the first symptom of a mechanical defect. In these cases, solving the noise problem can also improve the efficiency of the machine. In electric motors or generators, an eccentric or asymmetric air cap around the rotor causes deviations in magnetic forces and produces noise. The air intake or exhaust noise can be controlled or silenced by mufflers. However, in many cases the noise may spread through the entire casing and may be difficult to correct by changes in the machine or its connections. The solution then is to either line the machine with an absorptive or isolating material or to use separate enclosures.

3.12.6 Conclusions

In LCPs, the major sources of noise are various rotating machines, transformers and valves. The noise problem in LCPs is usually technically manageable, but, from a pragmatic point of view, the acceptable level of funds set aside for noise protection sets limits on the technical possibilities. Since increased distance from the source lowers noise, planning of land use both on a community level and within a specific industrial site is perhaps the best preventive measure to avoid noise problems. Inside the building, the same principle applies, i.e. the layout design should separate the working areas from noisy equipment.

With the encouragement of the authorities, there is a general target among machine manufacturers today to reduce the noise generated by equipment.

In a specific power plant example, the noise control technology is mainly based on:

- using acoustic machine enclosures
- selecting structures according to their noise isolation effect to envelope the building
- using mufflers in intake and exhaust channels
- using sound-absorptive materials in walls and ceilings
- using vibration isolators and flexible connections
- applying a carefully detailed design, e.g. to prevent possible leakage of noise through openings or to minimise pressure variations in piping.

In recent years, interest in noise has increased and has led to a series of noise regulations. Nowadays, the allowable noise level is a factor that should be taken into consideration in the main decisions in a power plant project.

3.13 Cooling techniques

The operation of large combustion plants is governed by ‘Carnot’s principle’. The heat source, i.e. the boiler, provides the energy required for the water vaporisation. The cold source, i.e. the condenser, condenses the steam coming out of the low pressure turbine. The condenser and the cooling system are, therefore, the key parts of the facility. Regardless of the mode of cooling adopted, it is in fact one of the main interfaces between the combustion plant and the surrounding environment. The efficiency and availability of a power plant depend, to a great extent, on the integrity and cleanness of the condenser and the cooling system. Table 3.16 presents the cooling techniques that are generally applied to large combustion plants according to their capacity.

Cooling system	Applied cooling temperatures (ºC)	Capacity of power generating process (MW_{th})
Open once-through systems	13 – 20 (terminal difference 3 – 5)	<2700
Open wet cooling tower	7 – 15	<2700
Open hybrid cooling tower	15 – 20	<2500
Dry air-cooled condenser	15 – 25	<900

Table 3.16: Examples of the capacity and thermodynamic characteristics of different cooling systems for applications in the power industry
[46, Caudron, 1991]

Within these configurations, a variety of applications can be found, all aimed at meeting process, site, environmental and economic requirements. The environmental impact of cooling techniques used in large combustion plants is described in the BREF on industrial cooling techniques.

3.14 Emission monitoring and reporting

This section is intended to give general information on the monitoring and reporting of emissions from the combustion of fossil fuel. The methods and instruments used for the monitoring of emissions should be the relevant national or international methods (e.g. European Committee for Standardisation (CEN); ISO; VDI Richtlinien; Netherlands Emission Regulations; UK Guidance Notes: British Standards, etc.). For more detailed information on general monitoring issues, reference is made to the dedicated Monitoring BREF.

3.14.1 Emission components

The most common emission components to air that are measured from LCPs using fossil fuels or that are calculated using emission factors and other methods are:

- particulate matter emissions, e.g. from the unloading, storage (short- and long-term storage) and handling of fuel
- dust as stack emissions (including PM_{10} and $PM_{2.5}$)
- sulphur oxides
- nitrogen oxides (NO_X)
- nitrous oxide (may be generated by fluidised bed combustion)
- heavy metals
- carbon monoxide
- carbon dioxide
- hydrogen fluoride (may be caused by carryover from the rotating heat-exchanger, combustion air preheater)
- halide compounds
- ammonia NH_3
- hydrocarbons (as unburned hydrocarbons, UHC)
- volatile organic compounds (VOCs)
- dioxins and/or POPs.

For water pollution, the following parameters can be monitored:

- suspended solids
- heavy metals
- salts (chloride and sulphate)
- organic halides
- biocides
- phosphate
- altered pH-values.

The pH-value and the other components are reported as a whole or partly in the fuel-specific chapters, depending on the fuel used and the availability of data. Methods of analysis are given in relevant national and international guidelines on monitoring and analysis.

3.14.2 Reference conditions and parameters

For emissions to air, the following off-gas parameters should also be determined to convert the emission concentrations obtained to standard conditions, i.e. 273 K, 101.3 kPa, measured oxygen content and dry gas:

- the volumetric off-gas flow (in order to calculate the concentration and emission mass flow)
- the off-gas temperature
- the water vapour content of the off-gas
- the static pressure in the off-gas duct
- the atmospheric pressure
- monitoring period/averaging period.

In addition to the above-mentioned parameters, for good operation of the boiler and the flue-gas cleaning system, additional measurements of certain parameters (such as voltage and electricity (electrostatic precipitators), pressure drop (bag filters), pH of scrubbing fluid (scrubbers)) and pollutant concentrations at various sites within the flue-gas ducts are necessary.

3.14.3 Sampling locations

The sampling points should meet the requirements of the relevant national guidelines. With respect to sampling (Figure 3.42).

The two main types of continuous emissions monitoring (CEM) are:

- *in situ*, where the sample is analysed in the stack or duct with little or no sampling treatment
- extractive, where a sample is withdrawn for analysis elsewhere (either to an on-site laboratory or for an off-site contractor).

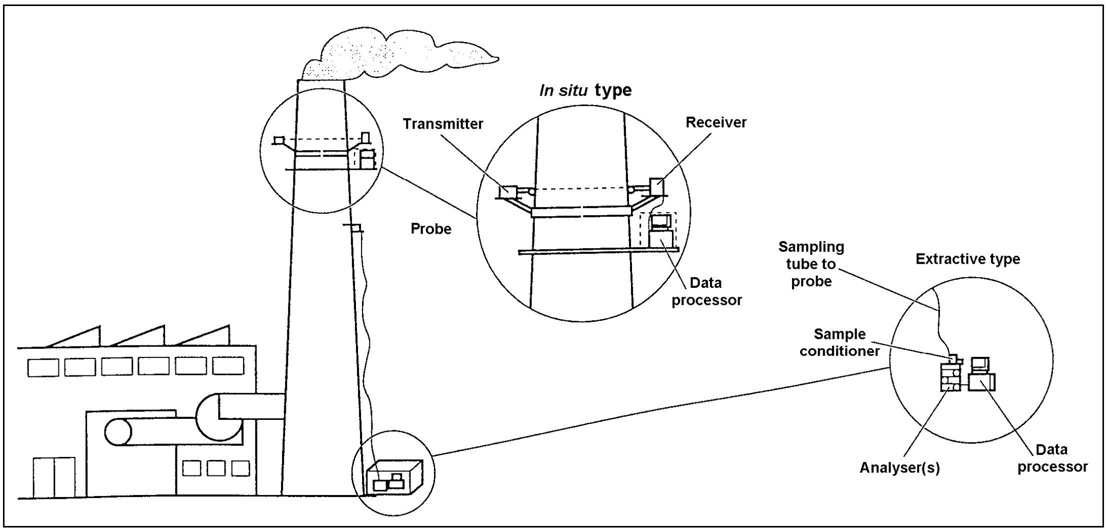

Figure 3.42: Two source of emissions-monitoring configurations
[106, Sloss, 1997]

The sampling points typically:

- are representative
- are clearly marked
- if possible, have a disturbance-free flow in the measurement section
- have monitoring points that can be closed
- have the required energy supplies
- meet the requirements for healthy and safety at work.

3.14.4 Monitoring of emissions

The monitoring of emissions is carried out to determine the substances in the clean gas or waste water so that they can be reported, or it may be carried out to control the combustion process or abatement plant or used to predict the environmental impact of the plant or process. An example of applied process control and air emission monitoring in power plants is presented in Figure 3.43.

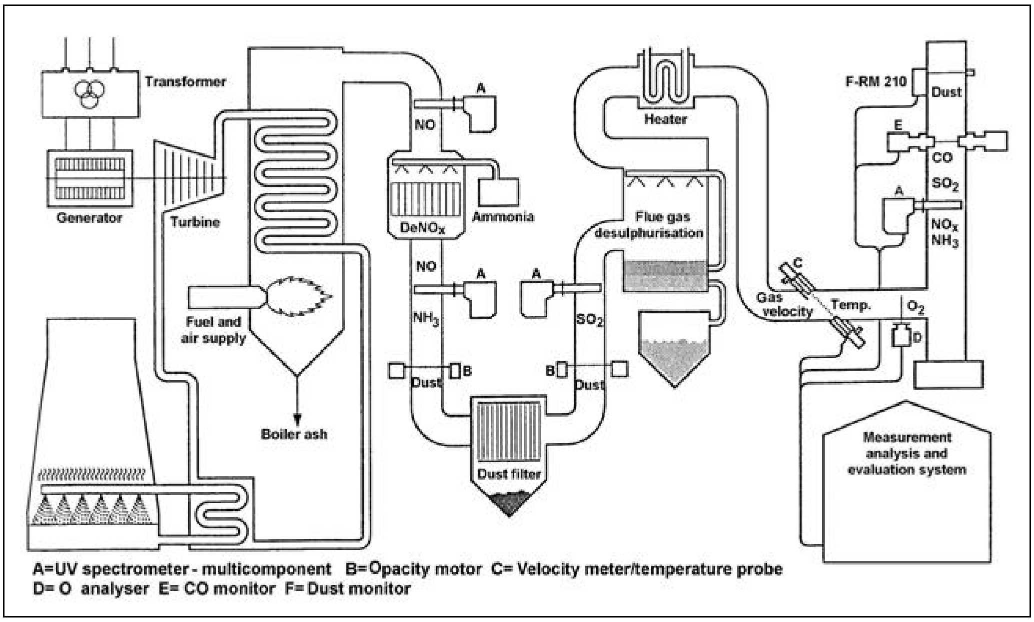

Figure 3.43: An example of process control and air emissions monitoring in power plants [106, Sloss, 1997]

Monitoring analysis can be carried out by direct measurements (i.e. direct source testing) or by calculations based on the measurement of operating parameters. For new plants and for substantial changes to a plant, emission factors might be used to estimate emissions to the environment.

Prior to carrying out measurements, monitoring plans can be made to take account of:

- the mode of operation (emergency or stand-by plants, plants with a reduced operating time according to energy demand e.g. peak and middle load plants and base-load or full-time plants)
- the operating state of off-gas purification or effluent treatment plants
- operating conditions in the plant (continuous, discontinuous, start-up and shut down operations), and
- the effect of thermodynamic interference factors.

These factors form the basis for selecting the following operating conditions:

- at which the highest emissions may be recorded
- for choosing the number and duration of the measurements
- for choosing the most appropriate method of measurement
- for determining the position of the measurement locations and specific measurement points. For waste water emissions qualified random samples can be used or 24-hour composite samples based on flow proportional or the time averaged samples taken.

For continuous operations, a minimum sample collection time or measurement time of half an hour (half-hour mean value) is usually necessary. For determining substances such as PCDD/PCDF, longer measurement times and consequently, other reference times may be necessary because of the limit of detection. For continuous operation, when there are only slight fluctuations in the emission characteristics, three individual measurements can be made at the highest emission level. Sampling or measuring takes place only during the operation of the plant and dilution air is excluded.

3.14.4.1 Continuous monitoring

In general, direct measurements are the most accurate and preferred methods of monitoring emissions. Continuous emission monitoring of a number of components in gases or in waste water is possible and in several cases, accurate concentrations (mg/Nm^3, ppm or mg/l) can be reported continuously or as mean values over agreed time periods (half hourly, daily, etc.). However, conditions for this are that the existing infrastructure is good and trained operating personnel for the equipment are available (for calibration procedures, etc.). In these cases, an analysis of the averages and the use of percentiles provides a flexible method for demonstrating compliance with permit conditions. Prime mover differences such as over/under pressures in the flue-gas, pressure fluctuations, flue-gas temperature, etc. are to be taken into account in the choice of the equipment. In these cases, discountinuous measurements, e.g. annual/six monthly measurements where practical are preferred.

3.14.4.2 Discontinuous measurements

In cases where continuous monitoring is not practicable, the value will be the average over the sampling period. Concentrations in waste water are often given as a total of soluble and insoluble material.

3.14.4.3 Emission estimations based on the measurement of operating parameters

It is not always necessary to measure the direct emissions from a source to quantify the actual emissions. For sources that have relatively high-quality emission factors or emission estimation algorithms that have been demonstrated to predict emissions with a high degree of accuracy over the typical range of operating conditions, emissions can be monitored by collecting and processing these activity data [1, Corinair, 1996].The use of adequately determined emission factors may produce more reliable and robust data in respect of total emissions than a few spot samples/measurements.

Predictive emission monitoring systems are widely used on gas turbines to determine $NO_X/CO/CO_2$ releases. These systems are computer based and rely on the recording of a number of process variables such as fuel flow, combustion temperature, ambient pressure/temperature etc. The parameters are then processed via an algorithm specific to each installation to derive relevant pollutant concentrations in releases to air and mass releases. The systems are usually calibrated by discontinuous monitoring once a year and have been demonstrated to be very accurate. There are also proprietary packages and some packages are commercially available.

Fuel analysis can be used to predict compounds such as SO_2 or CO_2 and elements such as metals and other emissions based on the application of conservation laws, if the fuel throughput is measured. The presence of certain elements such as sulphur and metals in the fuel can then be used to calculate their presence in the raw off-gas streams [2, ESAA, 1999]. Assuming complete conversion of sulphur, SO_2 emissions, for instance, from oil combustion, can be calculated based on the content of sulphur present in the oil.

3.14.4.4 Emission factors

If no measured data are available, emission factors can also be used to estimate emissions from large combustion plants. Emission factors can be based either on fuel consumption (g/tonne of fuel consumed), or energy consumption (g/GJ of energy input).

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

To determine the emitted amount of a pollutant by using an emission factor it is also necessary to have information about the activity rate of the plant. The activity rate and the emission factor have to be determined on the same level of aggregation (i.e. on the plant as a whole or on a boiler-by-boiler level) by using available data (e.g. fuel consumption). For the activity rate, the energy input in (GJ) is used, but in principle other relations are also applicable.

To obtain emission factors, two different approaches are proposed:

General emission factor: The general emission factor is a mean value for defined categories of boilers taking into account abatement measures (primary and secondary). A general emission factor is only related to the type of fuel used and is applicable to all pollutants considered, except SO_2. It cannot be applied to SO_2 because the sulphur content in the fuel is required for the appropriate determination of SO_2 emissions. General emission factors should only be used (as a provisional measure) where no technique specific data are available.

Specified emission factor: The specified emission factor is an individually defined value for boilers taking into account abatement measures (primary and secondary). A specified emission factor is related to individual fuel characteristics (e.g. sulphur content of fuel) and to technology-specific parameters.

In principle, plant specific data should be used, if available, for the determination of emission factors. Each emission factor, activity and production data parameter is assigned a letter data quality rating according to the following definitions. According to [1, Corinair, 1996] the following guidelines apply:

A An estimate based on a large number of measurements made at a large number of facilities that fully represent the sector.

B An estimate based on a large number of measurements made at a large number of facilities that represent a large part of the sector.

C An estimate based on a number of measurements made at a small number of representative facilities, or an engineering judgement based on a number of relevant facts.

D An estimate based on a single measurement or an engineering calculation derived from a number of relevant facts and some assumptions.

E An estimate based on an engineering calculation derived from assumptions only.

For further detailed information on emission estimations using emission factors and the overall quality rating by combining different quality ratings, for instance for the emission factor and the activity rate, please consult the EMEP/CORINAIR Atmospheric Emission Inventory Guidebook [1, Corinair, 1996].

3.14.5 Reporting emission data

All measurement reports and measurement protocols need to conform to the relevant national and international guidelines.

Typically, the report contains:

- the objective for the monitoring campaign
- general information on the measurements
- a description of the plant, its state and operating data
- operating conditions during the measurement
- information on the measurement planning
- details of the sampling locations
- descriptions of the measurement methods
- tabular presentation of the individual measurements, including temperatures, gas flowrates or volumes
- an evaluation of the results
- a consideration of errors
- a presentation of the quality assurance measures, and
- a summary.

3.15 Environmental management tools

Description: The best environmental performance is usually achieved by the installation of the best technology and its operation in the most effective and efficient manner. This is recognised by the IPPC Directive definition of ‘techniques’ as ‘both the technology used and the way in which the installation is designed, built, maintained, operated and decommissioned’.

For IPPC installations an Environmental Management System (EMS) is a tool that operators can use to address these design, construction, maintenance, operation and decommissioning issues in a systematic, demonstrable way. An EMS includes the organisational structure, responsibilities, practices, procedures, processes and resources for developing, implementing, maintaining, reviewing and monitoring the environmental policy. Environmental Management Systems are most effective and efficient where they form an inherent part of the overall management and operation of an installation.

Within the European Union, many organisations have decided on a voluntary basis to implement environmental management systems based on EN ISO 14001:1996 or the EU Eco-management and audit scheme EMAS. EMAS includes the management system requirements of EN ISO 14001, but places additional emphasis on legal compliance, environmental performance and employee involvement; it also requires external verification of the management system and validation of a public environmental statement (in EN ISO 14001 self-declaration is an alternative to external verification). There are also many organisations that have decided to put in place non-standardised EMSs.

While both standardised systems (EN ISO 14001:1996 and EMAS) and non-standardised (‘customised’) systems in principle take the organisation as the entity, this document takes a more narrow approach, not including all activities of the organisation e.g. with regard to their products and services, due to the fact that the regulated entity under the IPPC Directive is the *installation* (as defined in Article 2).

An environmental management system (EMS) for an IPPC installation can contain the following components:

(a) definition of an environmental policy
(b) planning and establishing objectives and targets
(c) implementation and operation of procedures
(d) checking and corrective action
(e) management review
(f) preparation of a regular environmental statement
(g) validation by certification body or external EMS verifier
(h) design considerations for end-of-life plant decommissioning
(i) development of cleaner technologies
(j) benchmarking.

These features are explained in somewhat greater detail below. For detailed information on components (a) to (g), which are all included in EMAS, the reader is referred to the reference literature indicated below.

(a) **Definition of an environmental policy**

Top management are responsible for defining an environmental policy for an installation and ensuring that it:

- is appropriate to the nature, scale and environmental impacts of the activities
- includes a commitment to pollution prevention and control
- includes a commitment to comply with all relevant applicable environmental legislation and regulations, and with other requirements to which the organisation subscribes
- provides the framework for setting and reviewing environmental objectives and targets
- is documented and communicated to all employees
- is available to the public and all interested parties.

(b) **Planning, i.e.**

- procedures to identify the environmental aspects of the installation, in order to determine those activities which have or can have significant impacts on the environment, and to keep this information up-to-date
- procedures to identify and have access to legal and other requirements to which the organisation subscribes and that are applicable to the environmental aspects of its activities
- establishing and reviewing documented environmental objectives and targets, taking into consideration the legal and other requirements and the views of interested parties
- establishing and regularly updating an environmental management programme, including designation of responsibility for achieving objectives and targets at each relevant function and level as well as the means and timeframe by which they are to be achieved.

(c) Implementation and operation of procedures

It is important to have systems in place to ensure that procedures are known, understood and complied with, therefore effective environmental management includes:

(i) Structure and responsibility

- defining, documenting and communicating roles, responsibilities and authorities, which includes appointing one specific management representative
- providing resources essential to the implementation and control of the environmental management system, including human resources and specialised skills, technology and financial resources.

(ii) Training, awareness and competence

- identifying training needs to ensure that all personnel whose work may significantly affect the environmental impacts of the activity have received appropriate training.

(iii) Communication

- establishing and maintaining procedures for internal communication between the various levels and functions of the installation, as well as procedures that foster a dialogue with external interested parties and procedures for receiving, documenting and, where reasonable, responding to relevant communication from external interested parties.

(iv) Employee involvement

- involving employees in the process aimed at achieving a high level of environmental performance by applying appropriate forms of participation such as the suggestion-book system or project-based group works or environmental committees.

(v) Documentation

- establishing and maintaining up-to-date information, in paper or electronic form, to describe the core elements of the management system and their interaction and to provide direction to related documentation.

(vi) Efficient process control

- adequate control of processes under all modes of operation, i.e. preparation, start-up, routine operation, shutdown and abnormal conditions
- identifying the key performance indicators and methods for measuring and controlling these parameters (e.g. flow, pressure, temperature, composition and quantity)
- documenting and analysing abnormal operating conditions to identify the root causes and then addressing these to ensure that events do not recur (this can be facilitated by a ‘no-blame’ culture where the identification of causes is more important than apportioning blame to individuals).

(vii) Maintenance programme

- establishing a structured programme for maintenance based on technical descriptions of the equipment, norms etc. as well as any equipment failures and consequences
- supporting the maintenance programme by appropriate record keeping systems and diagnostic testing
- clearly allocating responsibility for the planning and execution of maintenance.

(viii) Emergency preparedness and response

- establishing and maintaining procedures to identify the potential for and response to accidents and emergency situations, and for preventing and mitigating the environmental impacts that may be associated with them.

(d) Checking and corrective action, i.e.

(i) Monitoring and measurement

- establishing and maintaining documented procedures to monitor and measure, on a regular basis, the key characteristics of operations and activities that can have a significant impact on the environment, including the recording of information for tracking performance, relevant operational controls and conformance with the installation's environmental objectives and targets *(see also the Reference document on Monitoring of Emissions)*
- establishing and maintaining a documented procedure for periodically evaluating compliance with relevant environmental legislation and regulations.

(ii) Corrective and preventive action

- establishing and maintaining procedures for defining responsibility and authority for handling and investigating non-conformance with permit conditions, other legal requirements as well as objectives and targets, taking action to mitigate any impacts caused and for initiating and completing corrective and preventive action that are appropriate to the magnitude of the problem and commensurate with the environmental impact encountered.

(iii) Records

- establishing and maintaining procedures for the identification, maintenance and disposition of legible, identifiable and traceable environmental records, including training records and the results of audits and reviews.

(iv) Audit

- establishing and maintaining (a) programme(s) and procedures for periodic environmental management system audits that include discussions with personnel, inspection of operating conditions and equipment and reviewing of records and documentation and that results in a written report, to be carried out impartially and objectively by employees (internal audits) or external parties (external audits), covering the audit scope, frequency and methodologies, as well as the responsibilities and requirements for conducting audits and reporting results, in order to determine whether or not the environmental management system conforms to planned arrangements and has been properly implemented and maintained
- completing the audit or audit cycle, as appropriate, at intervals of no longer than three years, depending on the nature, scale and complexity of the activities, the significance of associated environmental impacts, the importance and urgency of the problems detected by previous audits and the history of environmental problems – more complex activities with a more significant environmental impact are audited more frequently
- having appropriate mechanisms in place to ensure that the audit results are followed up.

(v) Periodic evaluation of legal compliance

- reviewing compliance with the applicable environmental legislation and the conditions of the environmental permit(s) held by the installation
- documentation of the evaluation.

(e) Management review, i.e.

- reviewing, by top management, at intervals that it determines, the environmental management system, to ensure its continuing suitability, adequacy and effectiveness
- ensuring that the necessary information is collected to allow management to carry out this evaluation
- documentation of the review.

(f) Preparation of a regular environmental statement

- preparing an environmental statement that pays particular attention to the results achieved by the installation against its environmental objectives and targets. It is regularly produced – from once a year to less frequently depending on the significance of emissions, waste generation etc. It considers the information needs of relevant interested parties and it is publicly available (e.g. in electronic publications, libraries etc.).

- when producing a statement, the operator may use relevant existing environmental performance indicators, making sure that the indicators chosen:
    - give an accurate appraisal of the installation's performance
    - are understandable and unambiguous
    - allow for year on year comparison to assess the development of the environmental performance of the installation
    - allow for comparison with sector, national or regional benchmarks as appropriate
    - allow for comparison with regulatory requirements as appropriate.

(g) Validation by certification body or external EMS verifier

- having the management system, audit procedure and environmental statement examined and validated by an accredited certification body or an external EMS verifier can, if carried out properly, enhance the credibility of the system.

(h) Design considerations for end-of-life plant decommissioning

- giving consideration to the environmental impact from the eventual decommissioning of the unit at the stage of designing a new plant, as forethought makes decommissioning easier, cleaner and cheaper
- decommissioning poses environmental risks for the contamination of land (and groundwater) and generates large quantities of solid waste. Preventive techniques are process-specific but general considerations may include:
    - avoiding underground structures
    - incorporating features that facilitate dismantling
    - choosing surface finishes that are easily decontaminated
    - using an equipment configuration that minimises trapped chemicals and facilitates drain-down or washing
    - designing flexible, self-contained units that enable phased closure
    - using biodegradable and recyclable materials where possible.

(i) Development of cleaner technologies

- environmental protection should be an inherent feature of any process design activities carried out by the operator, since techniques incorporated at the earliest possible design stage are both more effective and cheaper. Giving consideration to the development of cleaner technologies can for instance occur through R&D activities or studies. As an alternative to internal activities, arrangements can be made to keep abreast with – and where appropriate – commission work by other operators or research institutes active in the relevant field.

(j) Benchmarking, i.e.:

- carrying out systematic and regular comparisons with sector, national or regional benchmarks, including for energy efficiency and energy conservation activities, choice of input materials, emissions to air and discharges to water (using for example the European Pollutant Emission Register, EPER), consumption of water and generation of waste.

Standardised and non-standardised EMSs

An EMS can take the form of a standardised or non-standardised (‘customised’) system. Implementation and adherence to an internationally accepted standardised system such as EN ISO 14001:1996 can give higher credibility to the EMS, especially when subject to a properly performed external verification. EMAS provides additional credibility due to the interaction with the public through the environmental statement and the mechanism to ensure compliance with the applicable environmental legislation. However, non-standardised systems can in principle be equally effective provided that they are properly designed and implemented.

Achieved environmental benefits: Implementation of and adherence to an EMS focuses the attention of the operator on the environmental performance of the installation. In particular, the maintenance of and compliance with clear operating procedures for both normal and abnormal situations and the associated lines of responsibility should ensure that the installation’s permit conditions and other environmental targets and objectives are met at all times.

Environmental management systems typically ensure the continuous improvement of the environmental performance of the installation. The poorer the starting point is, the more significant short-term improvements can be expected. If the installation already has a good overall environmental performance, the system helps the operator to maintain the high performance level.

Cross-media effects: Environmental management techniques are designed to address the overall environmental impact, which is consistent with the integrated approach of the IPPC Directive.

Operational data: No specific information reported.

Applicability: The components described above can typically be applied to all IPPC installations. The scope (e.g. level of detail) and nature of the EMS (e.g. standardised or non-standardised) will generally be related to the nature, scale and complexity of the installation, and the range of environmental impacts it may have.

Economics: It is difficult to accurately determine the costs and economic benefits of introducing and maintaining a good EMS. A number of studies are presented below. However, these are just examples and their results are not entirely coherent. They might not be representative for all sectors across the EU and should thus be treated with caution.

A Swedish study carried out in 1999 surveyed all 360 ISO-certified and EMAS-registered companies in Sweden. With a response rate of 50 %, it concluded among other things that:

- the expenses for introducing and operating EMS are high but not unreasonably so, save in the case of very small companies. Expenses are expected to decrease in the future
- a higher degree of co-ordination and integration of EMS with other management systems is seen as a possible way to decrease costs
- half of all the environmental objectives and targets give payback within one year through cost savings and/or increased revenue
- the largest cost savings were made through decreased expenditure on energy, waste treatment and raw materials
- most of the companies think that their position on the market has been strengthened through the EMS. One-third of the companies report increasing revenue due to EMS.

In some Member States reduced supervision fees are charged if the installation has a certification.

A number of studies[5] show that there is an inverse relationship between company size and the cost of implementing an EMS. A similar inverse relationship exists for the payback period of invested capital. Both elements imply a less favourable cost-benefit relationship for implementing an EMS in SMEs compared to larger companies.

According to a Swiss study, the average cost for building and operating ISO 14001 can vary:

- for a company with between 1 and 49 employees: CHF 64000 (EUR 44000) for building the EMS and CHF 16000 (EUR 11000) per year for operating it
- for an industrial site with more than 250 employees: CHF 367000 (EUR 252000) for building the EMS and CHF 155000 (EUR 106000) per year for operating it.

These average figures do not necessarily represent the actual cost for a given industrial site because this cost is also highly dependent on the number of significant items (pollutants, energy consumption, etc.) and on the complexity of the problems to be studied.

A recent German study [169, Schaltegger and Wagner, 2002] shows the following costs for EMAS for different branches. It can be noted that these figures are much lower than those of the Swiss study quoted above. This is a confirmation of the difficulty in determining the costs of an EMS.

Costs for building (EUR):
minimum - 18750
maximum - 75000
average - 50000

Costs for validation (EUR):
minimum - 5000
maximum - 12500
average - 6000

A study by the German Institute of Entrepreneurs [170, UNI/ASU, 1997] gives information about the average savings achieved for EMAS per year and the average payback time. For example, for implementation costs of EUR 80000 they found average savings of EUR 50000 per year, corresponding to a payback time of about one and a half years.

External costs relating to verification of the system can be estimated from guidance issued by the International Accreditation Forum (http://www.iaf.nu).

Driving forces for implementation: Environmental management systems can provide a number of advantages, for example:

- improved insight into the environmental aspects of the company
- improved basis for decision-making
- improved motivation of personnel
- additional opportunities for operational cost reduction and product quality improvement
- improved environmental performance
- improved company image
- reduced liability, insurance and non-compliance costs
- increased attractiveness for employees, customers and investors
- increased trust of regulators, which could lead to reduced regulatory oversight
- improved relationship with environmental groups.

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[5] E.g. Dyllick and Hamschmidt (2000, 73) quoted in Klemisch H. and R. Holger, *Umweltmanagementsysteme in kleinen und mittleren Unternehmen – Befunde bisheriger Umsetzung,* KNI Papers 01 / 02, January 2002, p 15; Clausen J., M. Keil and M. Jungwirth, *The State of EMAS in the EU. Eco-Management as a Tool for Sustainable Development – Literature Study,* Institute for Ecological Economy Research (Berlin) and Ecologic – Institute for International and European Environmental Policy (Berlin), 2002, p 15.

Example plants: The features described under (a) to (e) above are elements of EN ISO 14001:1996 and the European Community Eco-Management and Audit Scheme (EMAS), whereas the features (f) and (g) are specific to EMAS. These two standardised systems are applied in a number of IPPC installations. As an example, 357 organisations within the EU chemical and chemical products industry (NACE code 24) were EMAS registered in July 2002, most of which operate IPPC installations.

In the UK, the Environment Agency of England and Wales carried out a survey among IPC (the precursor to IPPC) regulated installations in 2001. It showed that 32 % of respondents were certified to ISO 14001 (corresponding to 21 % of all IPC installations) and 7 % were EMAS registered. All cement works in the UK (around 20) are certified to ISO 14001 and the majority are EMAS registered. In Ireland, where the establishment of an EMS (not necessarily of a standardised nature) is required in IPC licenses, an estimated 100 out of approximately 500 licensed installations have established an EMS according to ISO 14001, with the other 400 installations having opted for a non-standardised EMS.

Reference literature: [194, EC, 2002].

3.15.1 BAT for environmental management

A number of environmental management techniques are determined as BAT. The scope (e.g. level of detail) and nature of the EMS (e.g. standardised or non-standardised) will generally be related to the nature, scale and complexity of the installation, and the range of environmental impacts it may have.

BAT is to implement and adhere to an Environmental Management System (EMS) that incorporates, as appropriate to individual circumstances, the following features: (see section above)

- definition of an environmental policy for the installation by top management (commitment of the top management is regarded as a precondition for a successful application of other features of the EMS)
- planning and establishing the necessary procedures
- implementation of the procedures, paying particular attention to
    - structure and responsibility
    - training, awareness and competence
    - communication
    - employee involvement
    - documentation
    - efficient process control
    - maintenance programme
    - emergency preparedness and response
    - safeguarding compliance with environmental legislation.
- checking performance and taking corrective action, paying particular attention to
    - monitoring and measurement *(see also the Reference document on Monitoring of Emissions)*
    - corrective and preventive action
    - maintenance of records
    - independent (where practicable) internal auditing in order to determine whether or not the environmental management system conforms to planned arrangements and has been properly implemented and maintained.

- review by top management.

Three further features, which can complement the above stepwise, are considered as supporting measures. However, their absence is generally not inconsistent with BAT. These three additional steps are:

- having the management system and audit procedure examined and validated by an accredited certification body or an external EMS verifier
- preparation and publication (and possibly external validation) of a regular environmental statement describing all the significant environmental aspects of the installation, allowing for year-by-year comparison against environmental objectives and targets as well as with sector benchmarks as appropriate
- implementation and adherence to an internationally accepted voluntary system such as EMAS and EN ISO 14001:1996. This voluntary step could give higher credibility to the EMS. In particular EMAS, which embodies all the above-mentioned features, gives higher credibility. However, non-standardised systems can in principle be equally effective provided that they are properly designed and implemented.

Specifically for this industry sector*, it is also important to consider the following potential features of the EMS:

- giving consideration to the environmental impact from the eventual decommissioning of the unit at the stage of designing a new plant
- giving consideration to the development of cleaner technologies
- where practicable, sectoral benchmarking on a regular basis, including energy efficiency and energy conservation activities, choice of input materials, emissions to air, discharges to water, consumption of water and generation of waste.

3.16 An introduction to the integrated approach of protecting the environment as a whole

In the following text, the integrated approach is discussed from three points of view [59, Finnish LCP WG, 2000]:

- mutual influence of the emission reduction techniques for different pollutants through the inherent characteristics of the LCP process in question
- dependence on the performance of a given pollutant emission abatement technique as a function of the influence of other environment media, energy, consumables, generated streams and quality of waste substances and their economics
- the need to find an appropriate balance between environmental benefits (reduction of different pollutant emissions), cross-media effects and the money and energy spent.

An example of mutual influence in LCP pollution is the interdependence between the emissions of NO_X from a low NO_X burner, the unburned carbon, CO and hydrocarbons. Attempts to minimise the NO_X formation, at some point cause the unburned fraction of the fuel to increase rapidly. This not only reduces combustion efficiency, but also creates new pollutants, CO and unburned hydrocarbons, which cannot be removed from the flue-gas at a reasonable cost. Furthermore, beyond a limit of 5 % unburned carbon in the fly ash, the fly ash is no longer recyclable into cement or for the construction industry, creating the need for fly ash deposition in landfills.

Another example is the dependence of NO_X and N_2O formation on the fluidised bed combustion temperature. NO_X formation can be minimised by decreasing the FBC bed temperature, but, at some point, the rate of N_2O formation starts to increase. A compromise has to be found between combustion temperatures and a judgement made about which one will achieve the best overall balance. In addition to the oxides of nitrogen, sulphur capture in an FBC bed by limestone addition is also influenced by the bed temperature.

Yet another example is the catalytic reduction of NO_X. While it provides an effective means to reduce NO_X emissions, it introduces a tiny ammonia emission (ammonia slip) into the environment. Moreover, the transportation, handling and storage of ammonia itself creates an environmental hazard. The risk is less severe at smaller plants where an aqueous solution of ammonia is customarily used but, at large plants where liquid ammonia is used, the consequences of an accident may be severe.

When considering the performance of a pollution abatement technique versus the cost in money of applying that technique, as well as the requirements for energy and consumables and the need to handle any waste substances created, the general rule of thumb in many techniques is that better results can be achieved by investing more money. An example is sulphur reduction in fluidised bed combustion boilers. The degree of sulphur capture by limestone addition into the FBC bed improves as more excess limestone is used. Therefore, a high sulphur reduction simultaneously demands an increased use of limestone. This in turn means higher amounts of ash to deposit somewhere. Both the use of limestone and the increased amount of ash are environmentally undesirable side effects of improved sulphur capture in an FBCB. Another result of a high Ca content in the ash may be that it renders the ash unusable. The situation with respect to Ca consumption is qualitatively similar in semi-dry flue-gas desulphurisation.

In wet-scrubbing desulphurisation, excess calcium is not needed. Moreover, it cannot be used if commercial quality gypsum is the desired end-product. However, to achieve a higher reduction efficiency, a larger scrubbing reactor is required, and more electric energy is spent in the scrubbing suspension circulation pumps, the induced draft fans associated with the scrubber and in the associated heat-exchangers. When high sulphur reduction is desired, the increase in Ca consumption and gypsum production is small, but more electric energy is consumed and thus more CO_2 is released to the air.

The particle removal efficiency of both the electrostatic precipitator and the baghouse can be increased almost indefinitely by increasing the size, and hence also the cost of the equipment. The conditions with respect to the selective catalytic reduction of NO_X are analogous: by adding more catalyst elements, better reduction and lower ammonia slip can be achieved.

4 COMBUSTION TECHNIQUES FOR COAL AND LIGNITE

The current situation of coal- and lignite-fired large combustion plants in the EU, regarding capacity, number of units and age of the plants are presented in Figure 4.1– Figure 4.4.

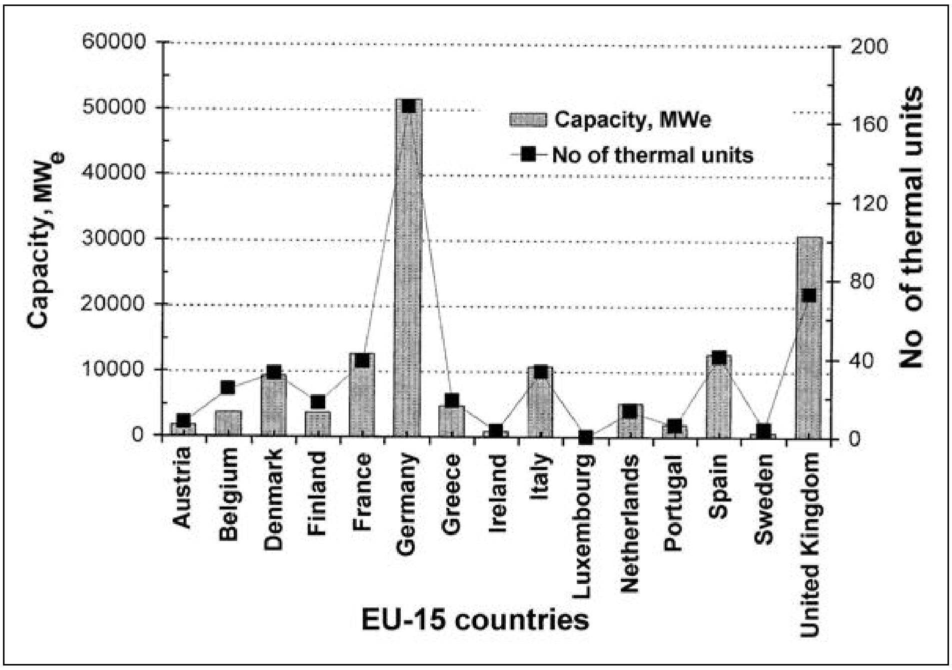


Figure 4.1: Coal- and lignite-fired power plants in EU-15 countries [110, Kakaras and Grammelis, 2000]

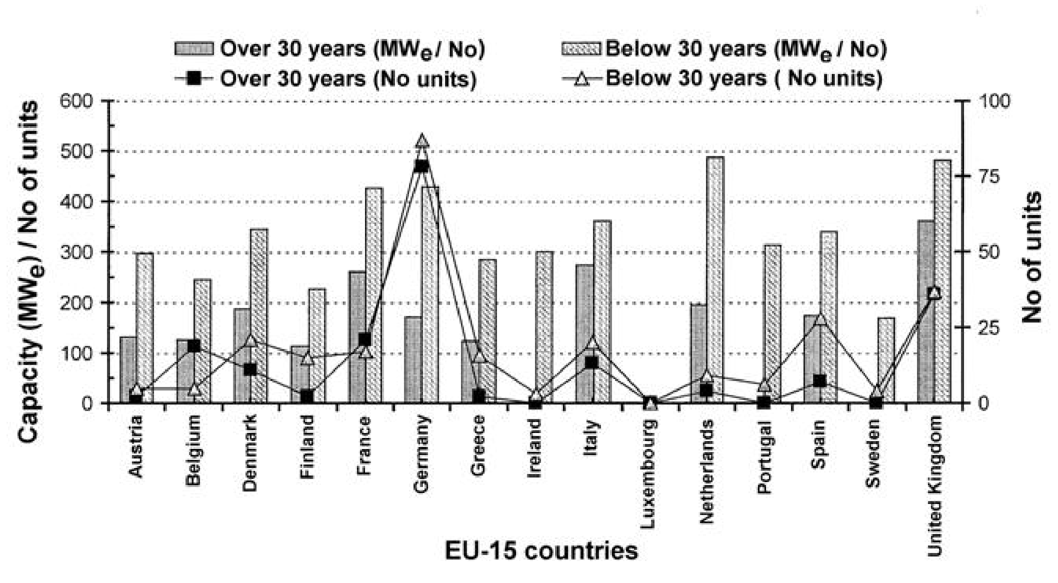


Figure 4.2: Capacity and age of coal- and lignite-fired power plants in EU-15 countries [110, Kakaras and Grammelis, 2000]

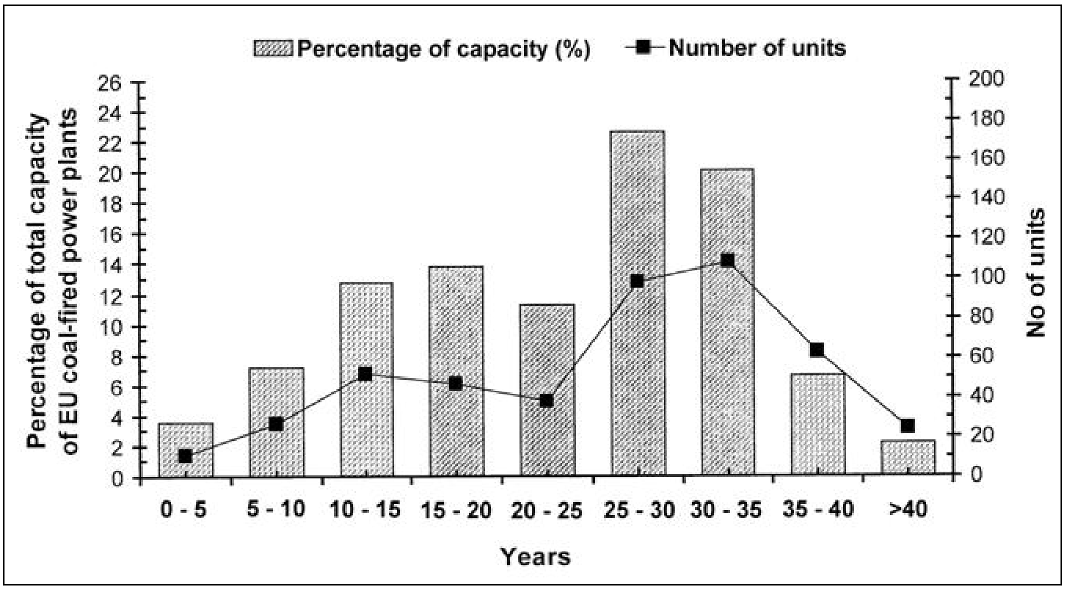


Figure 4.3: Age of coal- and lignite-fired power plants in EU-15 countries
[110, Kakaras and Grammelis, 2000]

Figure 4.4: Capacity weighted average age of coal- and lignite-fired power plants in EU-15 countries
[110, Kakaras and Grammelis, 2000]

4.1 Applied processes and techniques

In most countries, fossil-fuelled condensing power plants using hard coal and lignite are the backbone of the power generation system. In this part of the chapter, information is provided about processes and techniques applied in large coal and lignite-fired combustion plants.

4.1.1 Unloading, storage and handling of coal, lignite and additives

4.1.1.1 Coal and lignite

Solid fuels such as coal and lignite are supplied by ships, trains, and lorries, depending on the transport distance involved and what transport systems are available at mines and LCP sites. Unloading normally takes place with belt conveyors. LCPs near to mines or harbours may also be supplied with fuel directly from the mine or harbour by belt conveyors.

Coal and lignite are normally stored in open stockpiles (coal yards) with a storage capacity from few days up to three month use, and in several cases even enough supply for up to one year of operation. This additional storage capacity helps fuel supply security, as it lessens the dependence on transport logistics. The capacity of the storage facility depends on various parameters, such as, for example, fuel prices and availability, the company’s stock policy, security of the supply and on weather conditions. Fuel is normally transferred from the stockpile to the plant using belt conveyors. A buffer storage (e.g. coal bunkers with a capacity for a few hours operation, usually from 4 to 24 hours) exists within the LCP to cover periods when delivery from the coal yard is not possible.

The storage and transport of fuel can cause dust formation. For this reason, open stockpiles may be sprayed with water to control fine dust particle emissions, unless the fuel’s moisture is already high enough so that spraying is not necessary. During open loading and unloading of the stockpile, the height of the fuel drop onto the stockpile or between belt conveyors has to be as low as possible to avoid fugitive dust emissions. In urban regions, transport systems are often closed-systems and operated with pressures below atmospheric pressure, to minimise fugitive emissions. Fabric filters are often used to clean the collected air of dispersed fuel particles.

For certain solid fuels, full enclosure during both transport and storage is now being specified. This is, for instance, the case with petroleum coke, where fine dust enriched with higher levels of nickel, vanadium and PAHs can be relesed by transport and storage.

4.1.1.2 Additives and treatment reagents

Additives and chemical treatment reagents are often used for a variety of purposes in a combustion plant. They may be used in abatement equipment, such as desulphurisation plants, and for reducing nitrogen oxides, as well as in water and waste water treatment plants. For instance, chemical reagents are used as additives for boiler make-up water and biocides are used in cooling systems.

The supplier or employer specifies the appropriate storage of these materials. As reagents can react together, the storage and handling methods applied usually involve segregating any reactive materials. Liquids are usually stored in drums or tanks in open or enclosed bunded areas, acid- or chemical-resistant coatings are also used. Fine pulverised solids such as lime are generally stored indoors in silos, in drums or bags and with isolated drainage systems. Coarse structured solid raw materials are often stored in open storage areas. Pneumatic or mechanical (e.g. screw conveyors, bucket elevators, etc.) transportation systems are used to transport the materials.

The distribution of gases within the site is normally carried out inside pipelines, which are situated overhead, and which include good damage protection systems. Health and safety regulations govern the storage, handling and distribution of liquid or gaseous ammonia, which are used in SCR and SNCR plants to reduce NO_X emissions.

4.1.2 Pretreatment of coal and lignite

Careful selection of the coal is an effective way of reducing air and water emissions and of reducing residues. Low levels of sulphur and ash need to be given particular attention when using coal as a fuel when using commercially supplied or imported coal. It is important to use fuels with a high energy content and which incur minimum transport and handling costs. The risk of fire and explosion is a major risk from the pretreatment of coal.

To achieve a constant fuel quality, which helps to optimise the combustion process, coal is sometimes blended or mixed, depending on the specification range of the combustion plant. This mixing can be simply achieved by picking coal from the stockpile in a different sequence from the actual unloading sequence or by blending different types of coal in silos between the coal yard and the raw-coal bunkers.

The effects of a leaner fuel mix:

- CO_2-content in flue-gas drops
- flow of air and flue-gas increses
- O_2 content in flue-gas rises
- losses through exhaust gas increses
- energy consumption from fans, and specific CO_2 emission increase
- efficiency decreases.

Aim of a leaner fuel mix:

- drop of combustion chamber temperatures (dry bottom furnace)
- decrease of primary NO_X in flue-gas (less NH_3 consumption, longer operation period of SCR)
- decrease of CO content in combustion gas (less corrosion risk)
- decrease of unburned in fly ash (utilisation quality of fly ash)
- increased consumption of catalysts.

The effects of a richer fuel mix:

- CO_2 content in flue-gas rises
- flow of air and flue-gas drops
- O_2 content in flue-gas decreases
- losses through exhaust gas drops
- energy consumption from fan, and specific CO2 emission decrease.

Aim of a richer fuel mix:

- rise of combustion chamber temperature (slag tap furnace, better ash extraction)
- increase of efficiency.

Qualifying conditions:

- CO content in combustion gas should not increase
- no increase in unburned carbon fly ash (risk of higher corrosion or higher ash recirculation)

Aim independent of a lean or rich fuel mix:

- decrease of SO_x in flue-gas for plants without (or low efficient) FGD
- or increase of SO_x in flue-gas for efficient ESP operation (ash resistence).

Lignite is transferred from the lignite storage yard via belt conveyors (normally located under a roof) to the crusher house, where its size is reduced in hammer mills and two roller crushers to pieces of 80 – 40 mm or less. The crushed lignite is then transported via belt conveyors to the boiler bunkers. There are normally to six to eight bunkers to each boiler, each with enough capacity for four to eight hours of full operation of the steam generation unit with the mills operating at their nominal capacity with the worst lignite design quality. The lignite moisture at this stage is 45 – 70 %, so only insignificant amounts of lignite dust are emitted during transportation and crushing, except at the transfer points where, due to air draughts, lignite dust may be created, but this occurs only locally and even then only to a limited extent. In order to ensure healthy working conditions in the bunker house, the crusher house and with the lignite handling systems, all necessary measures are taken, for example by the installation of dedusting systems with air suction at the transfer points and at the closed belt conveyors. The air is cleaned in fabric filters to keep the dust concentration inside buildings below the maximum allowed concentration for working conditions.

4.1.3 Fuel preparation

4.1.3.1 Fuel preparation for pulverised hard coal combustion

Raw coal normally needs to be prepared properly for safe, economical and efficient use in a pulverising coal combustion system. In all coal pulverising systems, solid fuel is dried, ground, classified and then transported to the boilers.

For optimised combustion conditions, a maximum moisture content of 1 to 2 % is required for the solid fuel. To reduce the moisture content, the raw coal can be dried inside the coal mill.

Many mills are designed to reject, or are not adversely affected by, small inorganic or metallic materials. However, a magnetic separator could also be installed in the raw coal conveyor system to remove larger metallic objects. If this is not done, these objects may damage the conveyors or the pulveriser coal feeder, and could obstruct the coal flow.

A proper size selection of pulverised coal has significant effects on the operation and economics of the furnace system. Fine grinding is necessary to ensure a rapid ignition and complete combustion of carbon for maximum efficiency and to minimise ash and particulate deposits on heat-exchanger surfaces. However, the level of fineness is dictated by the cost of the grinding and is frequently subject to contradictory requirements of grinding costs versus operational and environmental benefits. Changes to the particle size distribution, and hence burning rate, for existing burners may also have an impact on NO_X emissions. Coal pulverisation is currently carried out in ball mills, impact mills, fan mills, or in roller and race mills. These are described in more detail below:

Ball mill: this consists of a horizontal cylinder with a lined interior of hard steel plates. It is about one-third filled with mixed sized forged steel balls of 30 – 80 mm diameter. The mill rotates with the balls and coal particles intermingling along the periphery of the cylinder. The coal particles are pulverised through the continuous cascading movement of the balls and the particles, with the coal particles being ground down by the rubbing and cascading action of the balls and other particles as they move over each other and over the liners. The resulting coal particles are then dried by hot air and transported to the classifier. Here oversized particles are separated and returned to the mill. Whilst the ball mill is simple in construction, its power consumption is high and does not vary much with load.

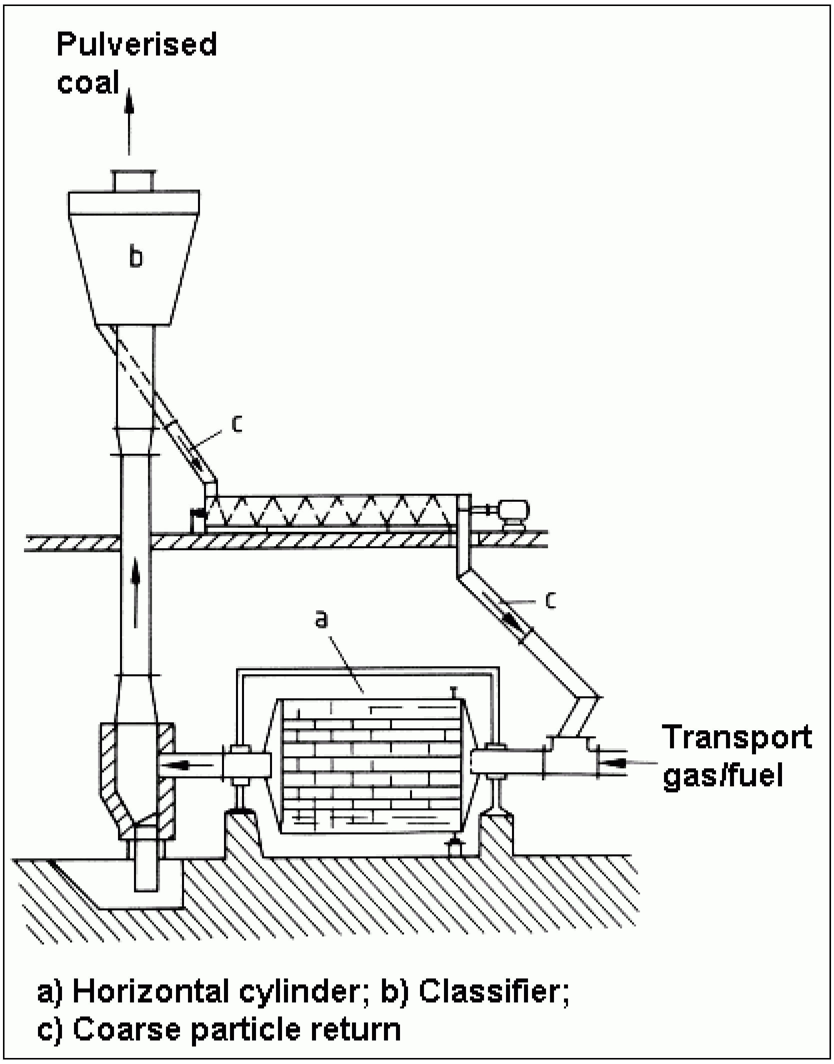


Figure 4.5: Ball coal mill
[79, Bell and Chiu, 2000]

Impact mill: this consists of a train of hinged or fixed hammer-like beaters that rotate in a chamber lined with wear-resistant plates. The coal is crushed by impact and attrition. Coarser particles gather near the periphery of the beaters due to centrifugal forces, and fine dust particles escape along the shaft. As well as grinding the coal, the impact mill also raises the pressure of the transport gas. This lends itself to the use of a centrifugal-type classifier that separates the oversized particles and returns them to the grinding zone. High head pressure is required to overcome pressure resistance in the mill, the classifiers, and in the coal/gas passages. When flue-gas is used for drying in the mill, the gas must come from that part of the furnace where the pressure is the highest. If the flue-gas contains SO_2, the wall temperature of the mill must remain above the acid dew point. Impact mills are less commonly used because their maximum capacity is lower than most other types.

Roller and race mill: here coal is pulverised between two surfaces, one rolling over the other. Three grinding rollers are installed with equal spacing around the mill pitch diameter. The grinding rollers are installed in a triangular frame loading system. This applies spring pressure through the roller bracket axles to load the rollers against the rotating grinding plate. The grinding ring, which shapes the ring race, is run at low speed. The roller diameter is c. 25 - 45 % of the ring diameter. As the raw coal is supplied through the feed pipe, it is mixed with partially ground coal and air that recirculates in the grinding zone. After the particles are reduced in size, they are dried and conveyed by heated air to an internal classifier. Oversized particles are returned to the grinding zone for further reduction, while undersized particles are conveyed to the burner for firing.

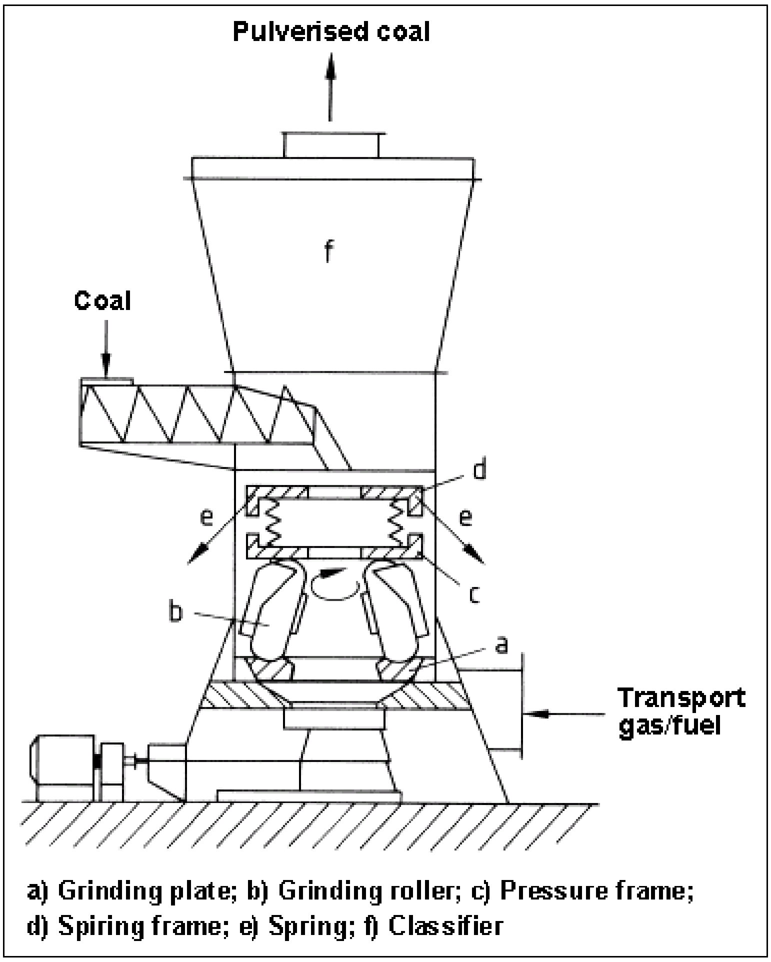


Figure 4.6: Roller and race coal mill
[79, Bell and Chiu, 2000]

Two other types of roller mills operate on the same principle. In the **bowl mill**, the grinding surfaces are rollers and a bowl, and in the **ball-race mill**, they are balls and ring races. The grinding surfaces maintain pressure through springs or hydraulic cylinders. In roller-type mills, the power requirement decreases as the 'Hardgrove Grindability Index' of the coal increases, also the power consumption per tonne of feed decreases as the feed rate increases. Typical roller mills reduce coal lumps of up to 5 cm diameter to a product that normally contains 70 % 200-mesh (74 μm) particles [79, Bell and Chiu, 2000].

Coal quality	Ball-race mills	Bowl mills	Ball mills
Low-volatile anthracite			■
High-volatile anthracite	■	■	■
Low-volatile bituminous coal	■	■	■
High-volatile bituminous coal	■	■	■

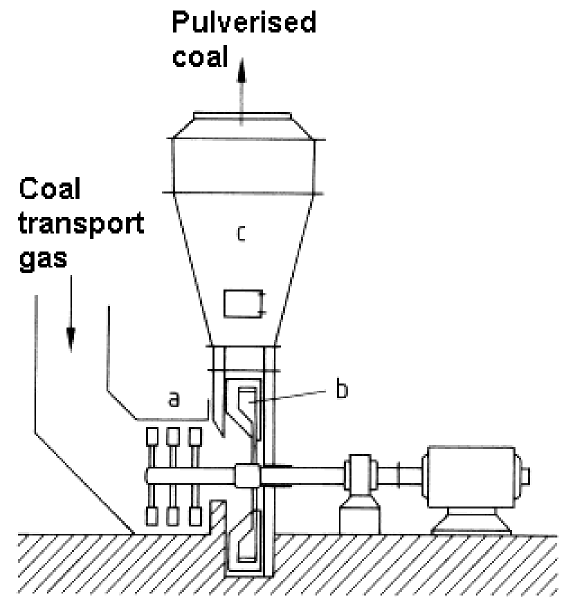
Table 4.1: Types of mills using different coal qualities
[58, Eurelectric, 2001]

Several methods of supplying and firing coal have been developed, including the direct-fired system or the storage (indirect) system. With the direct-firing system, pulverised coal is carried by the gas or airflow from the mill through transport pipes and distributed to the burners. With the indirect firing system, the pulverised coal is discharged into a transport loop equipped with a high-flow fan. It first passes through a classifier, where the coarse particles are recirculated to the mill, and is then collected in cyclones feeding the storage bin.

4.1.3.2 Fuel preparation for pulverised lignite combustion

The lignite is fed from the bunkers through closed feeders to the lignite mills. The feeders are specially designed (e.g. fan beater wheel type) for the type of local fuel utilised. They achieve three objectives: they pulverise, dry, and then distribute the fuel to the combustion chamber. Lignite pulverisation is aided by the presence of hot flue-gases, which are extracted from the boiler through recirculation ducting. The lignite particles are reduced to less than typically 90 µm size (approximately 60 % through a 70 mesh screen). The flue-gas heat reduces the lignite moisture content down from 45 – 70 % to 10 - 20 %, i.e. to the required level for optimum combustion conditions. Finally, the mixture of lignite dust, flue-gases and moisture, is fed to the boiler burners. This mixture can also contain air or cold flue-gas, when added in the mills.

Fan mill: here either a fan impeller or a series of impact blades located in front of the fan impeller is used on the same shaft or on different shafts. The fan enhances turbulent mixing and increases the relative and absolute velocity of the particles and the gas. Mixing contributes both to a uniform distribution of the coal particles over the impeller's circumference and also to a drying of coal with high moisture content. Lignite, which contains high moisture levels, may be coarsely ground [79, Bell and Chiu, 2000].



a) Impact blades; b) Fan impeller; c) Classifier

Figure 4.7: Fan mill for lignite milling
[79, Bell and Chiu, 2000]

When lignite of extremely low heating value and of high moisture content is used as the fuel, an additional step prior to feeding it into the combustion chamber is necessary, for more effective removal of lignite moisture. For this purpose, after the mills, a stream rich in lignite and moisture is directed to specially designed electrostatic precipitators, where the dry lignite particles are separated and then fed to the lower boiler burners. From the lignite electrostatic precipitators, the mixture of flue-gases and moisture is directed via induced fans to the stack or to the FGD.

4.1.3.3 Fuel preparation for fluidised bed combustion (FBC)

Fluidised bed combustion needs most solid fuels to be crushed. Depending on the fuel properties maximum grain sizes of between 3 and 20 mm are desired. The prepared fuel is transferred directly to the fluidised bed in the combustion chamber, where the average bed particle size is 1000 µm for bubbling fluidised bed combustion (BFBC) and 100 – 1000 µm for circulating fluidised bed combustion (CFBC).

4.1.3.4 Fuel preparation for grate firing (GF)

If combustion is to be carried out on grates, then normally there is only limited fuel preparation needed. Large pieces of solid fuel may be reduced in size in order to supply a more or less homogeneous particle size distribution into the combustion chamber for burning on the grate. The maximum size of the fuel particles is often determined by the feed systems for the combustion chamber and depending on the technical conditions of the grate.

4.1.4 Boiler types and steam generator

4.1.4.1 Condensing power plants

For detailed information on the technique, and the process of the condensing power plants and the steam cycle, reference is given to Chapter 2 of this document.

In most steam-only condensing power plants in operation today, the coal input to power output ratio (heat rate) is around 2.5 (i.e. efficiency: e = 40 %; LHV). In other words, for each unit of power output, 1.5 units of heat is lost into the atmosphere via the stack and into the cooling system, mainly via the condenser. The established standard practice since the 1960s has been to use either natural circulation boilers, with a boiler steam pressure at around 170 bars, or once-through boilers with a pressure of around 240 bars. In both cases, the superheating and reheating temperatures are around 540 or 570 ºC, depending on the selected tube materials. Using the most advanced high temperature materials, coal-fired condensing power plants with a steam pressure of approx. 300 bars and a steam temperature approaching 600 ºC have recently been built. For example, a coal-fired condensing plant with a net heat rate of 2.08 (e = 48 %) was commissioned in 1998 in Denmark using direct water cooling [61, MPS, 1998].

A lignite-fired power plant being built in Germany is another example of the latest condensing power technology. When built, it will achieve a net heat rate of 2.22 (e = 45 %) with lignite fuel and a wet cooling tower [62, Kallmeyer, et al., 1998]. A recently-built condensing lignite-fired power plant with an ESP, a wet FGD plant and a cooling tower discharge of flue-gases is shown in Figure 4.8.

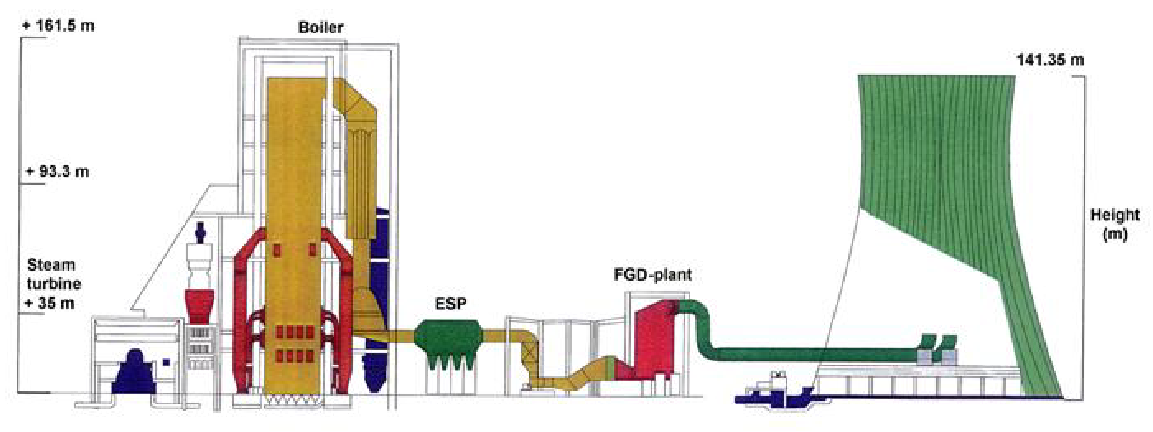


Figure 4.8: New large lignite-fired power plant with cooling tower discharge [92, VEAG, 2000]

Most of the new coal or lignite-fired condensing power plants built in the 1990s have had a net heat rate of around 2.3 (e = 43 %). When possible, direct once-through cooling is used to achieve the lowest possible condenser pressure and temperature, to maximise the plant power generation efficiency.

Today's condensing power plant units are usually quite large, typically with power outputs from 300 to 900 MW_{el}. At such big plants, the fuel is burned in pulverised coal burners. As larger fluidised bed combustion (FBC) boilers have become available, they have also been used in smaller condensing plants. Currently, the largest condensing FBC power generation unit in operation has a power output of 300 MW_{el}, and concept studies exist for a 600 MW_e unit. To control the NO_X emissions, special low NO_X burners and/or other primary NO_X abatement techniques are used. If these measures are not sufficient, selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) with urea or ammonia can be used to remove NO_X from the flue-gas.

Flue-gas desulphurisation at condensing power plants is typically performed with scrubbers fitted between the steam generator and the flue-gas stack. If fluidised bed combustion is used, desulphurisation is best achieved in the fluidised bed itself, e.g. by adding calcium carbonate into the bed, and then no end-of-pipe desulphurisation plant is needed.

The oldest environmental protection measure applied at conventional condensing power plants is the removal of ash and char particles from the flue-gas. The most popular method to achieve this is the electrostatic precipitator (ESP). Baghouses with fabric filters are also frequently used.

4.1.4.1.1 Dry bottom boiler (DBB)

Dry bottom boilers (DBB) or dry bottom furnaces are operated with temperatures below the melting temperature of the ash near to the chamber walls or to heat-exchangers. In the centre of the flame, temperatures are often higher than the melting point of the ash particles. 10 – 20 % of the ash is transferred to the dry bottom and is extracted as bottom ash, the remaining 80 – 90 % of the ash is transported with the flue-gas and then removed in the precipitators.

The DBB technique has the highest installed capacity of coal combustion in the world. New plants using this technique with single unit capacities of up to 950 MW_e are in operation for lignite combustion in Europe. In the US and Japan units have been built with even higher capacities for hard coal combustion.

4.1.4.1.2 Wet bottom boiler (WBB)

Wet bottom boilers (WBB), or slag (or granulate) tap furnaces with liquid ash removal, have been developed for use with combustion temperatures higher than the ash melting point (1400 ºC). These furnaces need special ceramic lining to withstand the molten ash temperatures and high temperature chemical attack. A large amount of ash is transported to the walls and flows in a liquid form down the walls and through the bottom outlet. Fly ash in this type of combustion system can be recycled to the combustion chamber to produce boiler slag as a by-product instead of fly ash. The composition of the ash depends on the composition of the coal. The wet bottom boiler is mainly used for the combustion of hard coal (anthracite hard coal) where the amount of volatiles is relatively low.

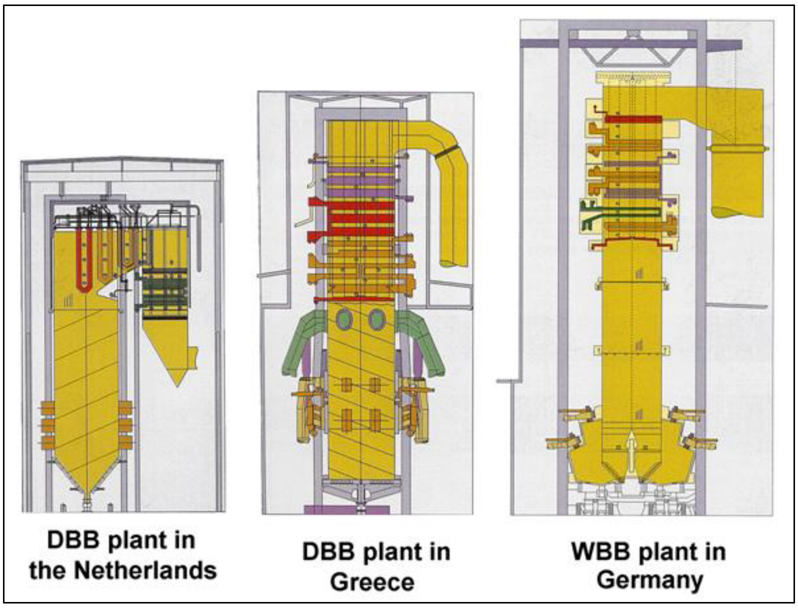


Figure 4.9: Examples of dry- and wet-bottom boilers operated in the EU
[80, Siemens, 2000]

4.1.4.1.3 Firing systems

In coal-burners, the fuel-gas mixture is forced through nozzles into the combustion chamber and burned with additional combustion air. Separate ignition/pilot burners are used during start-up, if necessary, for unstable combustion situations and for shut-down. These burners are supplied with fuel oil in most cases, but can also use gas or finely ground dry lignite. The burners are used to ensure re-ignition, if necessary, during unstable combustion situations. Coal and lignite boilers use the following fired systems:

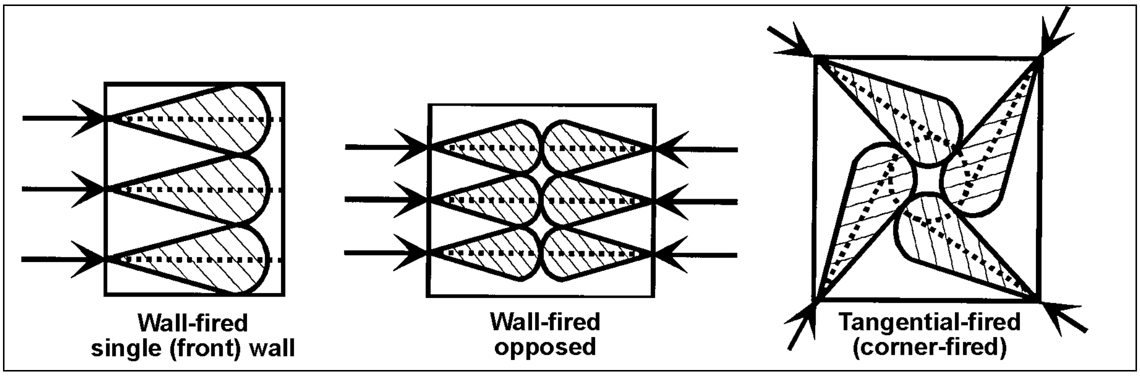


Figure 4.10: Different coal-burner configurations (main systems applied)
[32, Rentz, et al., 1999]

Wall- or front-fired systems: In horizontally wall-fired systems the fuel is mixed with combustion air. The burners are located in rows, either on the front wall only or on both the front and rear walls. The latter is called ‘opposed firing’. Once the coal is ignited, the hot combustion products provide the ignition energy necessary for stable combustion.

Tangential- or corner-fired systems: The tangentially-fired system is based on the concept of a single flame envelope. Both fuel and combustion air are projected from the vertical furnace corner windboxes along a line tangential to a small circle at the centre of the furnace. In some cases, the windbox nozzles can be automatically tilted to control the furnace exit-gas temperature, to maintain the heated or reheated steam at the system design temperature.

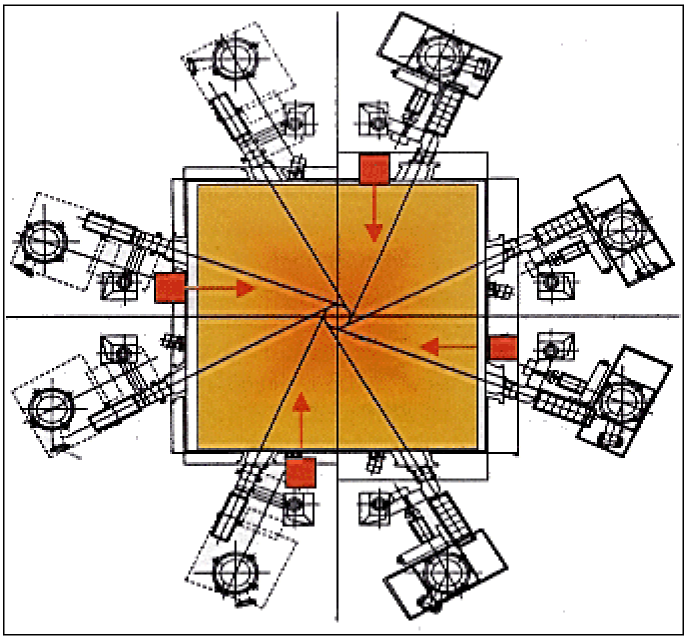


Figure 4.11: Tangentially-fired combustion chamber
[137, Elsen, et al., 2001]

Vertically-fired systems: The first pulverised-coal systems had a configuration called vertical or arch. They are now principally used to fire coals with volatile matter of between 8 and 15 % (dry basis). The firing system produces a long, looping flame in the lower furnace with the hot gases discharging up the centre.

4.1.4.2 Fluidised bed combustion (FBC)

Fluidised bed combustion takes place by the injection of fuel into a hot turbulent bed, where combustion air has been injected from the bottom of the fluidised bed boiler by fluidisation of the bed. As fluidised bed combustion (FBC) boilers have become available for coal and lignite, they have also especially been used as industrial combustion plants. Sand is normally used as the bed material essentially at start up. The bed of particles, including fuel (between 1 and 3 % of the bed material), ash and sorbents, is fluidised by upwards flowing air in a furnace, and the bed temperature allows the fuel to burn. Due to the combustion temperatures of about 750 - 950 ºC and the long residence time, the burnout of the fuel is very high and, therefore, the related emissions of combustion products are relatively low.

The fluidised bed technique is used for the combustion of coal rich in ash. Currently two different types of fluidised bed boilers exist, the bubbling fluidised bed combustion (BFBC) and the circulating fluidised bed combustion (CFBC).

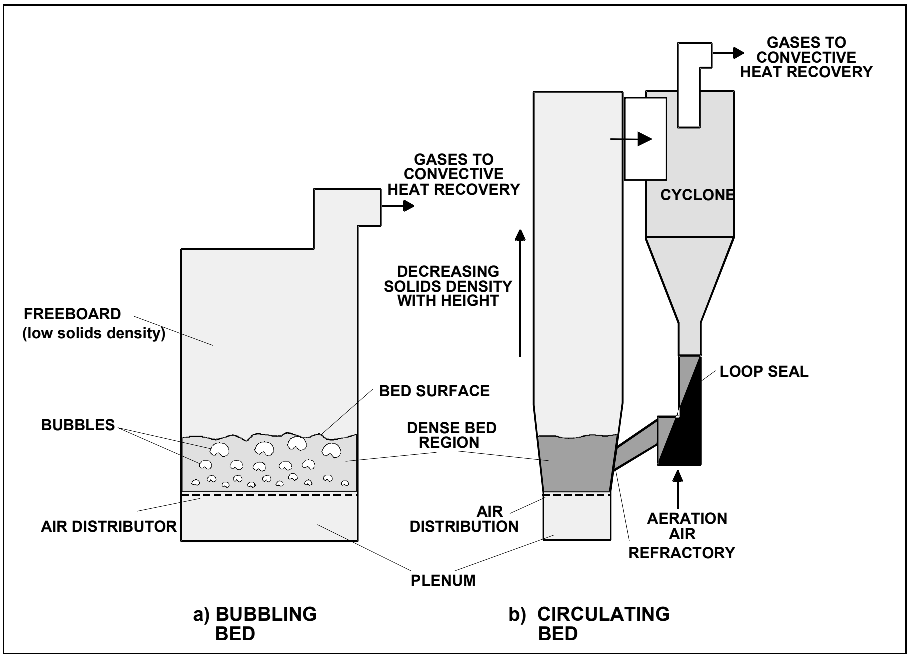


Figure 4.12: Schematic of the bubbling fluidised bed boiler and the circulating fluidised bed boiler [59, Finnish LCP WG, 2000]

In the latter case, i.e. in CFBC, air is blown into the bottom of the furnace, partly as primary air injected through a grid, and partly as secondary air some metres above the grid. The velocity of the air is high enough to carry the bed solids along with it, thereby filling the entire combustion chamber. The hot combustion gases carry the particles to the top of the combustion systems and into heavy-duty cyclones where they are separated and recirculated back into the bottom of the main combustion chamber. To enable SO_2 removal, crushed limestone or dolomite is added to the bed. The circulating bed systems increase the potential reaction time and the level of gas mixing, therefore generally leading to a more efficient combustion and fixation of sulphur.

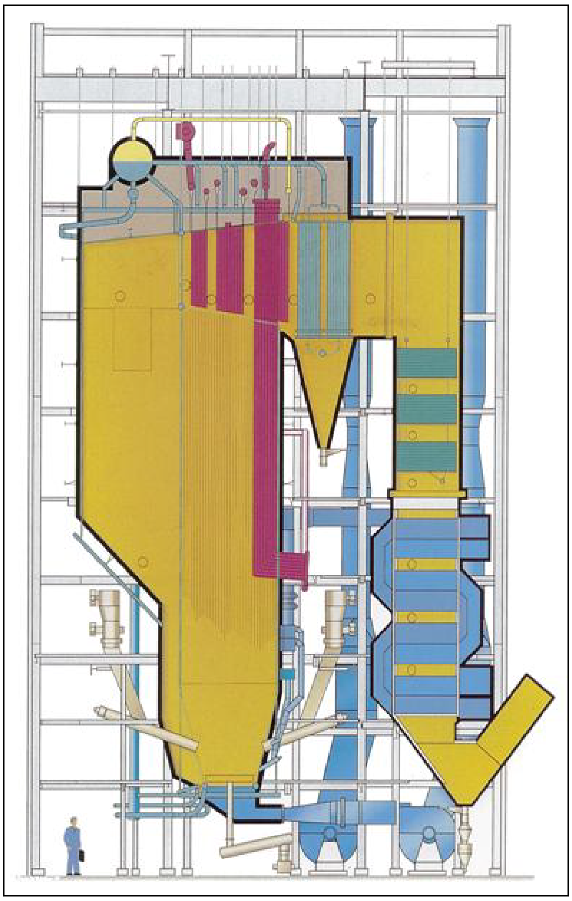


Figure 4.13: CFBC boiler for burning low-sulphur coal
[83, Foster Wheeler, 1995]

The level of heat transfer marks the main difference between the two fluidised bed combustion techniques. Coal contains only a low share of volatiles, which can be pyrolysed in the bed. About 60 – 80 % of coal consists of char, which can only be combusted. If this share remained in the adiabatic bubbling bed, it would accumulate there, unless more air were introduced for fluidising and combustion. This accumulation cannot be allowed, because even a short-term accumulation would increase the risk of losing bed temperature control. For this reason, the circulating bed (CFBC) is the most feasible fluidised bed combustion technology over 50 MW_{th} for coal as a main fuel. The necessity to burn coal char in the bed renders adiabatic combustion in a bubbling bed unfeasible. The bed energy balance requires that a substantial amount of combustion heat be released outside the adiabatic bubbling bed, as within the bed the released energy can only be used for pyrolysis and for evaporation of water in the fuel.

CFB includes a bubbling fluidised bed at the bottom of the furnace. The suspension density above the bed decreases with furnace height, as the bed material is recycled in the furnace along the furnace walls. The suspension density at the outlet of the furnace is typically 5 – 30 kg/m^3. This high share of circulating inert material smooths the temperature profile throughout the furnace. The cooling surfaces can, therefore, be located freely in the furnace or in the bed material circulation loop. In the furnace, very smooth heat transfer is achieved to all heat transfer surfaces, because the heat radiation of the dense suspension is not dependent on the radiation properties of the flue-gases.

Fluidised bed combustion is not very different from other combustion techniques. Bubbling fluidised bed combustion resembles grate-firing in many respects. The main benefit for combustion is the better temperature control. Circulating fluidised bed combustion resembles pulverised fuel combustion or burner combustion. One difference though, is the comprehensive temperature control of the furnace, which ensures ignition of the fuel without the need for a high temperature flame.

Comparison between bubbling and circulating fluidised bed techniques
The temperature of a fluidised bed is typically 800 – 900 ºC. The lower limit comes from the combustion reactivity of the fuels and the upper limit from the starting point of the fuel ash sintering.

In BFBC, the fuel is fed into the bed. Biofuels pyrolyse instantly once in contact with the hot bed. 30 – 40 % of the combustion air is used as the fluidising air and the rest is used for the combustion of pyrolysis gases in the so-called freeboard above the bubbling bed. Most of the finest particles also burn in the freeboard. The combustion temperature in the freeboard can be up to 1100 – 1200 ºC or even higher locally. The bubbling bed actually operates as an adiabatic combustor of fuel, and the low combustion temperature is a result of using the under-stoichiometric air ratio in the primary combustion zone.

In the freeboard of the BFBC furnace, other burners can be located and operated simultaneously with the bed. For example gas, oil and coal burners have been used.

Experience from the existing CFBC plants have shown that cyclone efficiency is a crucial parameter for proper functioning of the whole CFBC system. The cyclone efficiency has a major impact on the carbon burnout, limestone consumption, SO_2 and CO emissions and the temperature profile. The cyclone efficiency is mainly important for fuels such as low reactive fuels and fine grain fuels (coal slurry) because the better the cyclone efficiency is, the longer the char particles are kept in the furnace and less furnace inventory is lost via the cyclone.

The increase in cyclone efficiency enhances the solid circulation rate to a large extent thus ensuring a constantly high heat transfer in the furnace. Thus, the most favourable conditions for low NO_X and low SO_X emissions can be reached for a wide fuel range and load range. The latest cyclone modification includes an optimised arrangement and shape of the cyclone inlet duct, which is tilted downwards, and incorporates the advanced vortex finder design. The eccentric arrangement of the vortex has been retrofitted to different CFBC plants, where low ash brown coal is the main fuel, leading to substantial savings in limestone and sand costs for operators.

The benefit of the smaller particle inventory was, as predicted, improved carbon burnout and less limestone usage, but also less erosion occurs inside the furnace due to the smaller ash particles being less erosive.

Fuel does not need to be pulverised or dried for use in fluidised bed boilers. Mechanically crushing of the fuel is sufficient to facilitate its feeding into the bed. Fluidised beds can tolerate quite a wide particle size distribution and high moisture content because of the stabilising effect of the bed. Some size limitations are connected with the rotary fuel feeders. On the other hand, the pre-processing of reactive fuels is safer if they contain a moderate amount of moisture. The risks of explosive dust formation and fires in fuel processing and transportation are normally controlled by keeping the fuel moisture content above 40 %.

Heat transfer surfaces can corrode and erode, if they are located in a fluidised bed with a reducing atmosphere. The heaviest wear occurs when the reducing and oxidising atmospheres continually alternate. Therefore, boiler tubes in the bubbling bed area are protected by fireproof ceramic coatings. Vertical heat transfer surfaces located in the oxidising zone, such as membrane walls of the furnace, are best for resisting the wear from bed materials.

The choice between grate firing and fluidised bed firing depends on the quality of the ash and the amount of physical impurities in the fuel. Fuels with a low ash melting point cannot be burned in a fluidised bed, because the fluidisation will be disturbed quite rapidly. Heavy physical impurities such as metal particles in domestic waste also cannot be fluidised, as they sink onto the air distribution plate, disturb the fluidisation and are difficult to remove from the furnace. However, new solutions for keeping the bed operational with these fuels have been developed lately and are currently being successfully implemented.

As far as environmental considerations are concerned, FBC systems are able to reduce SO_2 emissions by limestone injection and can achieve a relatively low level of thermal NO_X formation because of the low combustion temperature. This is one of the reasons why this advanced combustion technique is being intensively developed more and more nowadays. Moreover, a wide range of fuels can be combusted in the same facility because these boilers are not so sensitive to the fuel specifications.

At the present time, fluidised bed boilers are in operation in Sweden, the UK, France, Finland, Germany, Poland and the US, and more recently in Asia. More than 400 units are operating today and availability levels are high.

4.1.4.3 Pressurised fluidised bed combustion

Based on the experience gathered with atmospheric fluidised bed combustion systems, the development of pressurised fluidised combustion (PFBC) started in the mid 1970s. PFBC systems offer the advantage of smaller plant sizes but at the same output, which require reduced investment costs and result in comparatively low emissions without the need for secondary emission reduction measures, and all at a thermal efficiency comparable or slightly higher than that of conventional coal firing plants. Because of the low combustion temperature, no thermal NO_X is formed, and fuel NO_X can be reduced during combustion by the introduction of ammonia into the freeboard or before the gas turbine. As in the case of atmospheric FBC, it is possible to differentiate between bubbling and circulating bed systems. Currently, all plants with a thermal capacity in excess of 50 MW_e are bubbling bed systems, but the development of circulating systems is now underway and the first two demonstration plants, with capacities of 80 MW_e and 65 MW_e/30 MW_{th}, started operating in 1997.

The main parts of a PFBC system are: the coal preparation and handling section; the pressurised bubbling or fluidised bed boiler; the hot gas clean up section, utilising ceramic candle filters or cyclones; the gas turbine; and the steam/water circuit of the steam turbine. Figure 4.14 shows a schematic drawing of a bubbling bed PFBC system.

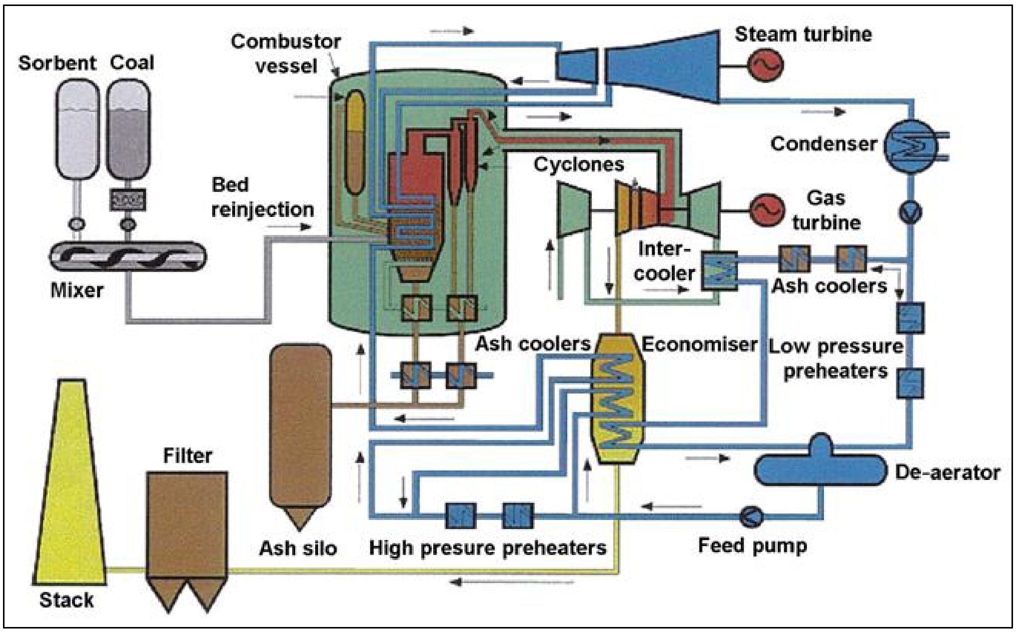


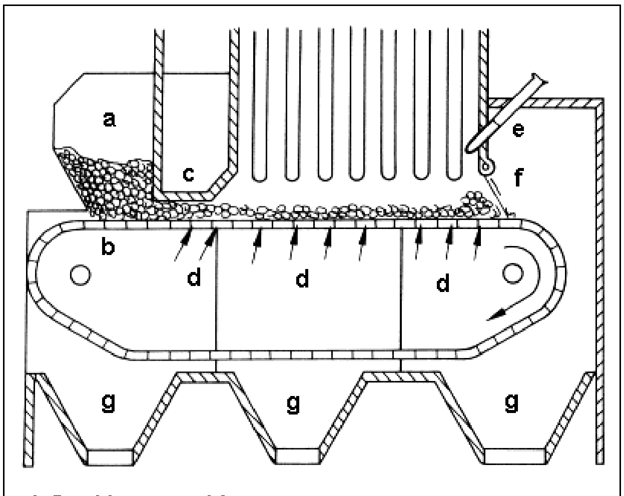
Figure 4.14: Schematic drawing of a bubbling bed PFBC system
[32, Rentz, et al., 1999]

Prior to combustion, coal is crushed and then mixed with limestone (dolomite). Except for one installation, all plants that have been built so far use hard coal as fuel. The mixture is fed via a pneumatic conveying system or a slurry feed pump across the pressure boundary and is then injected into the combustor from a series of feed points. Combustion air is first pressurised using a suitable gas turbine compressor and routed to the combustor containment vessel through the outer annulus of a coaxial duct, while hot combustion gases return to the turbine through the central passage. Combustion takes place inside the pressure vessel at a temperature of 850 °C to 900 °C and a pressure of approximately 1.6 MPa. The combustion chamber is equipped with immersed heat-exchangers, which allow for a constant combustion temperature and which produce high pressure steam which is utilised in the steam turbine. The hot flue-gases are first cleaned using ceramic candle filters or cyclones and then utilised in a gas turbine to generate electricity. Turbine exhaust gases are fed to a heat recovery steam generator and are used for boiler feed-water preheating and steam generation. The steam turbine produces about 80 % of the total electricity produced by the utility.

Currently, PFBC systems are able to achieve thermal efficiencies of up to 45 %. Further improvements are limited because of the comparatively low gas turbine inlet temperature, which is determined by the combustion temperature in the fluidised bed boiler. Several process schemes to increase the gas turbine inlet temperature, e.g. by an additional firing using natural gas or fuel oil, or by partial gasification of the feed coal prior to combustion and utilising the fuel gas in the gas turbine, have been proposed and are being investigated. These process configurations offer considerably higher efficiency values, but no pilot or demonstration plant has yet been built. As mentioned earlier, inherent emission control is one of the main features of PFBC technology [32, Rentz, et al., 1999].

4.1.4.4 Grate firing (GF)

Grate or spreader stoker combustion systems burn solid fuels on the grate or stoker system with air passing through the system floor. Most coarse solid fuels can be burned in these systems. The practice shows that coal can be fed as a mixed size grading, usually from 30 mm downwards, including very fine coal particles. Grate combustion systems work with a steady reservoir of fuel in the combustion chamber, but the coal can be left on the grate without the fans running, and are able to be rekindled quickly in the event of sudden demand for steam. If problems arise with the air supply, bypass operation is necessary. Grate firing is still an applied technology for smaller coal-fired boilers, mainly applied to industrial and local district heating plants.



a) Coal hopper; b) Travelling grate; c) Gate;
d) Primary air; e) Secondary air; f) Stow; g) Ash pit

Figure 4.15: Travelling grate-firing for coal combustion
[79, Bell and Chiu, 2000]

4.1.5 Integrated gasification combined cycle

The 'integrated gasification combined cycle' (IGCC) merges gasification with gas cleaning, synthesis gas conversion and turbine power technologies to produce clean and affordable energy. This integration of energy conversion processes provides more complete utilisation of energy resources, and offers high efficiencies and ultra low pollution levels. Furthermore, an IGCC can convert virtually any carbon-based feedstock into products such as electric power, steam, hydrogen, and value added chemicals. Different technical combinations enable industry to use low cost and readily available resources and wastes in highly efficient energy conversion options. These options can be selected to meet any of a whole host of market applications.

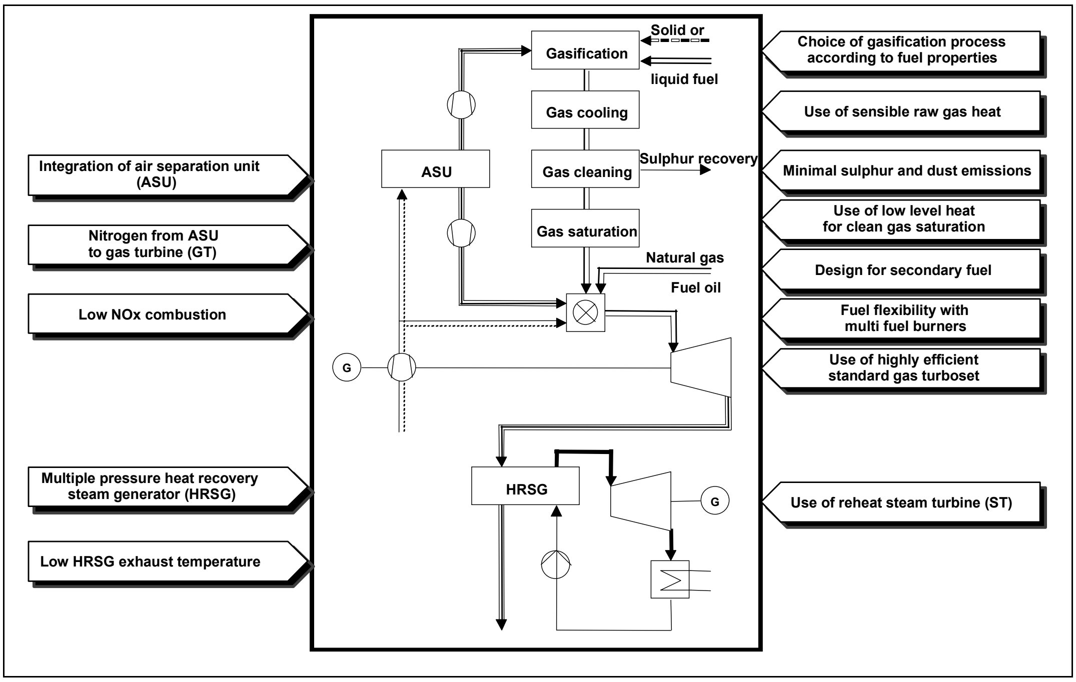


Figure 4.16: Main features of an oxygen-blown IGCC
[84, Siemens, 1999]

Within the general framework of an IGCC system, there are many options available regarding the type of gasifier that can be used (e.g. wet or dry coal feed system, air or oxygen blown, fixed bed, bubbling bed or entrained flow gasification) and the level of process integration possible.

The gasifier converts hydrocarbon feedstock into gaseous components by applying heat under pressure in the presence of steam. The partial oxidation of the feedstock, through injection of air or oxygen into the gasifier, provides the heat. Together, the heat and pressure break the bonds between the feedstock constituents, precipitating chemical reactions and producing syngas.

Minerals in the feedstock (ash) separate and leave the bottom of the gasifier as an inert glass-like slag or other marketable solid product. Only a small fraction of the ash becomes entrained, requiring removal downstream. Other potential pollutants, such as sulphur compounds, from hydrogen sulphide, from which the sulphur is extracted, typically occur as elemental sulphur or sulphuric acid which are both valuable by-products. Due to the reducing atmosphere in the gasifier, no NO_X is formed during the gasification process. Ammonia formed by the nitrogen/hydrogen reaction is stripped by process water, as are chlorides that might otherwise form acids. In IGCCs, the clean syngas remaining after pollutant separation is used, in whole or in part, to fuel a combustion turbine. The combustion turbine drives an electric generator, provides air under pressure to the gasifier and produces heat (exhaust) to generate steam to the gasifier, for steam turbine electric power or for other applications.

IGCC systems with cold gas cleaning are able to achieve relatively good NO_X emission values. This is due to the fact that fuel-bound nitrogen is almost removed in the scrubber of the cold gas cleaning section. Thermal NO_X formation in the combustion chamber of the gas turbine is suppressed by saturation of the fuel gas with steam prior to combustion and by dilution with nitrogen from the air separation unit. These emission reduction measures result in NO_X emissions of less than 25 mg/Nm^3 at an oxygen content of 15 % in the flue-gas. IGCC also reduces significantly the amount of particulates, SO_2 (5 mg/Nm^3), waste water and CO_2 discharged.

IGCC systems for using coal as a fuel are applied only at a very limited number of combustion plants.

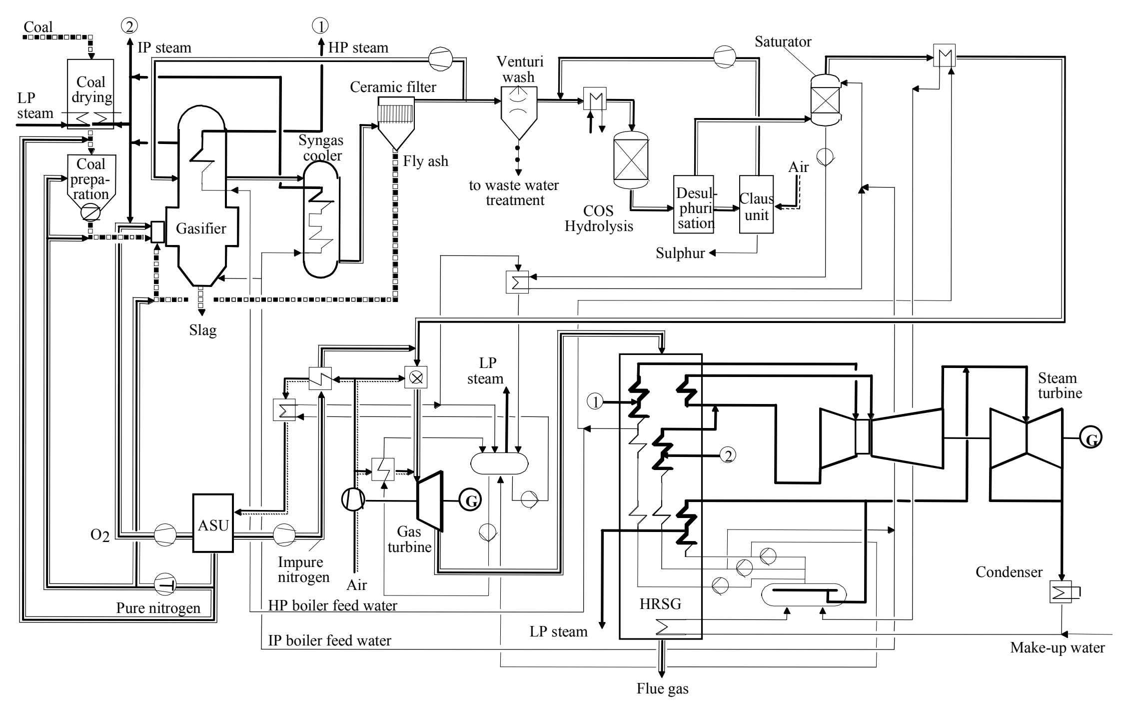


Figure 4.17: Flow sheet of an IGCC power plant operated in Spain
[84, Siemens, 1999]

IGCC offers thermodynamically favourable conditions of high pressure, high concentration of contaminants and low volumetric flows of syngas – as little as 1/100 of combustion products. This allows economical deep cleaning of sulphur and particulates. The majority of the pollutants are partitioned and captured in the IGCC gas cleaning process. The reducing conditions in gasification strongly favour conversion of fuel mercury to its elemental form. Elemental mercury can be reliably and easily removed by sulphinated activated carbon as has been already achieved in one site.

4.1.6 Co-generation (CHP)

Co-generation uses a single process to generate both electricity and usable heat. Co-generation or ‘the combined generation of heat and power’ (CHP) is proven technology, and is mainly applied to industrial plants where both electricity and heat (hot water or steam) are needed. In addition to cost savings, co-generation also yields environmental benefits though using fossil fuels more efficiently. This leads to fewer emissions than the separate generation of electricity and heat, and also to optimised fuel and exergetic efficiency.

Steam turbines driven by fossil fuel-fired boilers have been used for industrial co-generation systems for many years. High pressure steam raised in a conventional coal- or lignite-fired boiler is expanded within a turbine to generate mechanical energy, which can then be used to drive an electric generator. The amount of power generated depends on how much the steam pressure can be reduced though the turbine whilst still being able to meet the site heat energy needs. In some cases, the turbine is equipped with a separate or integrated low pressure cylinder, which enables electricity production independent of the heat supply

The advantages and the disadvantages of a co-generation system are [81, COGEN Europe, 1999]:

Advantages:

- high overall fuel and exergetic efficiency
- any type of fuel can be used
- the heat and power ratio can be varied
- the ability to meet more than one site heat grade requirement
- high reliability and availability, usually better than 98 %
- wide range of sizes available
- long working life.

Disadvantages:

- high heat to power ratio
- high cost.

4.1.7 Combined cycle combustion (repowering)

The idea of combined cycles has grown out of the need to improve the simple ‘Brayton’ (Joule)-cycle efficiency by utilising the waste heat in the turbine exhaust gas. This is a natural solution because the gas turbine is a relatively high temperature machine and the steam turbine a relatively low temperature machine. In the context of existing coal-fired combustion plants, combined cycle combustion is normally known as repowering. For general information on repowering, reference is given to Section 2.5.2 of this document.

The main objectives for repowering are to [82, Ciemat, 2000]:

- increase the power output
- enhance the performance
- improve the use of installed plant
- obtain a greater operating flexibility
- increase the reliability and availability
- reduce the operating and maintenance costs
- extend the plant lifetime
- reduce emissions and the volume of residues.

4.1.8 Efficiency of coal and lignite fired LCP

4.1.8.1 Boiler efficiency

For a clean and new boilers, it can be stated that the efficiency levels around 86 % - 94 % (LHV), are currently recorded for solid fuel, The main losses are associated with flue-gas waste heat via the stack, unburned carbon, waste heat in ash and radiation losses. The effect of fuel is important, assuming boilers with identical performance (same ambient and flue-gas temperature, same excess air, etc.) different boiler efficiencies are obtained depending on the nature of fuel as the following examples illustrate (LHV basis):

- international coal: 94 % efficiency
- lignite: 92 % efficiency
- low grate lignite: 86 %.

4.1.8.2 Techniques to increase coal-fired boiler efficiency

Coal-fired boiler efficiency is closely linked with the nature of the fuel and the temperature of the ambient air (the project-input data). However, optimisation of some parameters is possible:

- **unburned carbon in ash.** Optimisation of combustion leads to less unburned carbon in ash. It should be noted that NO_X abatement technologies by combustion modification show a tendency to increase unburned carbon.The target is to achieve the best burnout in order to the achieve the optimum efficiency or fuel utilisation. However, according to technical and fuel chracteristics in particular by burning anthracite coal, a higher content of unburned carbon in ash may occur
- **air excess**. Excess air is dependent on the type of boiler and on the nature of fuel. Typically, 20 % of excess air is the figure for pulverised coal fired boiler with a dry bottom. Due to combustion quality (CO and unburned carbon formation), boiler integrity (air in-leakage), corrosion and safety (risk of thermal excursions in the boiler) it is often not possible to reduce the excess air any further
- **flue-gas temperature.** The flue- gas temperature leaving the clean boiler (depending on fuel type) traditionally lies between 120 and 220 °C so as to avoid the risk of acid corrosion by condensation of sulphuric acid. However, some designs sometimes incorporate a second stage of air heater to lower this temperature below 100 °C, but with special cladding on the air heater and the stack, which makes this reduction economically less attractive.

4.1.9 Control of emissions to air from coal- and lignite-fired LCPs

Within the European Union, 4 % of coal- and lignite-fired combustion plants currently apply technical measures to reduce SO_2 emissions, 16 % apply techniques to reduce NO_X emissions, and about 54 % of plants apply both. The remaining 26 % have not yet applied techniques to reduce the emissions of SO_2 and NO_X [1, Corinair, 1996].

4.1.9.1 Control of emissions from pulverised fuel combustion

4.1.9.1.1 Fuel pretreatment

As a first step to minimise the generation of emissions, the raw materials used in the whole process as a fuel can be the improved, for instance by the following measures:

- by using a mixture of different coals with different characteristics and from different countries
- use of high quality coals with respect to high heating value, low water content, low ash content, low content of sulphur, chlorides and fluorides
- by applying coal washing/cleaning (see also 3.6.1)
- by coal gasification
- by homogenising the coal to ensure the standard quality of the final fuel.

4.1.9.1.2 Fuel switch

A fuel switch to fossil fuels with a lower content of potential pollution-generating compounds can lead to a significant reduction in pollution from combustion installations. This measure is widely applied. However, fuel switching options are limited by some aspects of adaptability for specific combustion installations concerning the use of different fuels and sometimes by long-term contracts between power producing companies and fuel suppliers. In general, the adaptability depends on the burners installed, and usually a switch from one coal type to another coal with a much better environmental profile (i.e. low sulphur content and low volatile material) or from hard coal to heavy oil is often possible with the burners installed. Switching from coal to gas, however, normally requires an exchange of the burners and a modification of heat exchangers. Any improvement in emission reduction then obviously depends on the fuel characteristics of the fuel initially used and on the new type of fuel [32, Rentz, et al., 1999]. However, the possible detrimental impact of any new coal on emissions should be considered, e.g. reduced ESP performance due to reduced sulphur content or reduced low NO_X burner performance with higher volatile coals.

4.1.9.1.3 Dust abatement

In pulverised coal combustion, the bulk of the ash is carried with the flue-gas out of the combustion chamber. Only a small quantity (<20 %) is collected as bottom ash in dry bottom boilers. Eighty per cent of the ash leaves the furnace as fly ash and this fly ash must be collected in the dust reduction equipment, such as ESP and fabric filters.

In wet bottom boilers, ash is liquefied by the high combustion temperature. This liquid ash flows with gravitational force to the slag tap. Even with high velocity gas flow, most ash is extracted as slag. Fly ash is often recirculated for this type of furnace, to extract almost all the ash as slag.

Amongst dust removal technologies, the ESP is (by far) the most commonly used equipment in Europe in power plants using hard coal or lignite. ESPs collect fly ash, generally in a dry form, that that can be recycled for use in road building or for manufacturing products such as cement and concrete and, as the last solution, it can be landfilled. Fuels can be supplied from different sources in the world, but ESP techniques with a high voltage intermittent energising system are able to react to different fuel qualities, including those with a lower sulphur content. Further developments are connected with high voltage peaking, with peak times of µs duration. In this short time, corona discharge is optimised, but flash-over cannot generate in this short time. This technique reduces electricity consumption of the ESP.

Cyclones are rarely used for de-dusting in LCPs. Nevertheless, two installations of this type (i.e. with pre-extraction of dust using the mechanical system upstream of the ESP) are being operated in France, in a 250 MW_e unit in combined application.

4.1.9.1.4 Abatement of mercury (Hg) emission

In general, no dedicated systems for Hg removal are currently applied at thermal power plants burning coal or lignite only. FF and ESP or wet scrubbers are designed for dust and SO_2, HCl and HF removal, respectively. The removal of Hg by these systems is an additional positive side effect. The abatement of Hg by flue-gas cleaning devices depends on the Hg specification. Both gaseous elemental mercury (Hg^0) and gaseous oxidised mercury (Hg^{2+}) are in the vapour phase at flue-gas cleaning temperatures. Hg^0 is insoluble in water and cannot be captured in wet scrubbers. The predominant Hg^{2+} compounds of coal flue-gas are weakly to strongly soluble, and the more soluble species can generally be captured in wet FGD scrubbers. Both Hg^0 and Hg^{2+} are adsorbed onto porous solids such as fly ash, in principle powered activated carbon which is relative costly, or calcium-based acid gas sorbents for subsequent collection in a dust control device. Hg^{2+} is generally easier to capture by adsorption than Hg^0. Particle-bound mercury Hg_p is attached to solids that can be readily captured in an ESP or fabric filter [171, UN ECE, 2002]. The removal efficiency in an ESP depends on the following factors:

- temperature of the ESP
- Cl-content in the coal
- unburned carbon in the ash
- calcium compounds in the ash.

Flue-gas cleaning techniques applied in combustion installations use three basic methods to capture Hg:

- capture of Hg in the dust of particulate matter control devices, such as an ESP or FF as a side effect
- adsorption of Hg^0 and Hg^{2+} onto entrained sorbents (injection of activated carbon) for subsequent capture in an ESP or FF. Alternatively, Hg may be captured in a packed carbon bed
- solvation of Hg^{2+} in wet scrubbers.

4.1.9.1.5 Abatement of SO_2 emissions

For the reduction of SO_2 emissions from coal- and lignite-fired combustion plants, almost all techniques described for desulphurisation of flue-gases in Chapter 3 (Common processes and techniques to reduce emissions from large combustion plants) are currently applied. The specific technique used depends on a variety of plant- and site-specific factors, such as the location, the thermal capacity and the load factor of the particular plant, as well as on the fuel and ash quality, e.g. certain low quality lignites with high alkaline ash and low sulphur content, generates (due to the natural desulphurisation that takes place during combustion) lower SO_2 emissions, that may even correspond, in specific cases, to up to 90 % SO_2 removal.

Figure 4.18: Retrofitting FGD technology into an existing plant
[94, Umwelt + Technik, 2000]

Dry and semi-dry techniques are applied more to smaller plants (<100 MW_{th}), whereas the wet scrubber technology is the dominant technique used in various applications in larger plants, i.e. over 300 MW_{th}. Absorber towers are designed as spray, packed or double loop towers. A good example of a wet FDG plant using a spray tower applied to a large coal-fired plant in the UK is presented in Figure 4.19.

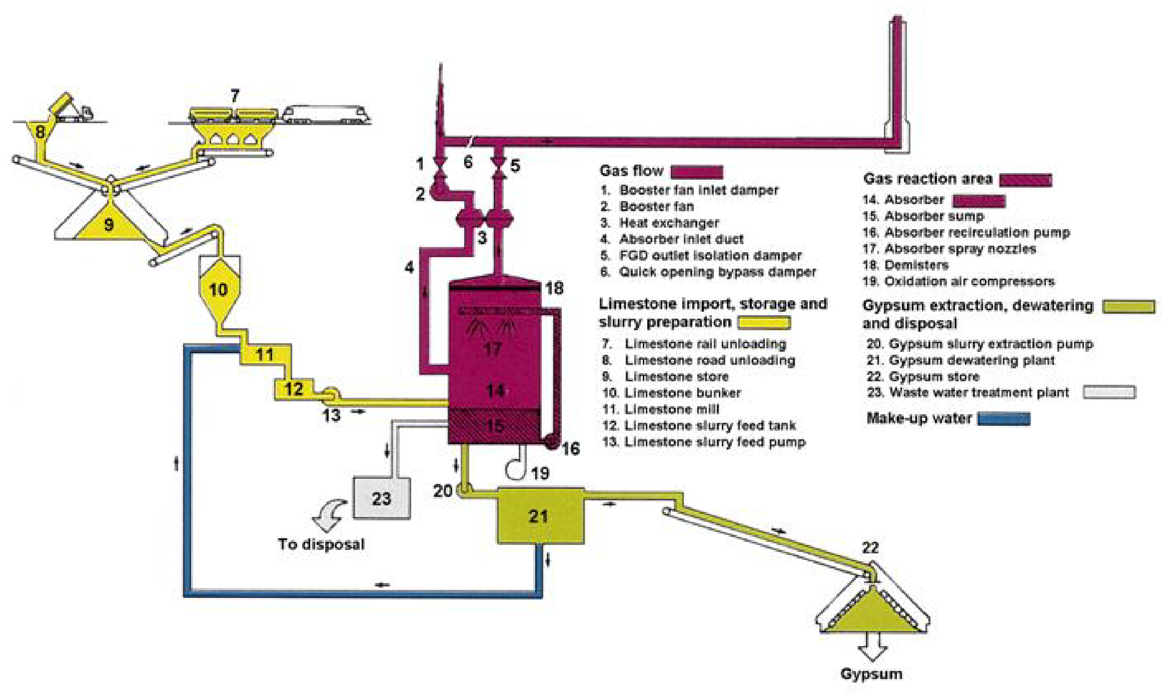


Figure 4.19: Wet FGD process with a spray tower
[93, Powergen, 2001]

A number of plants have installed new types of heat-exchangers for off-gas reheating, to avoid possible contamination of the scrubbed gas by raw flue-gas. (see Figure 4.20)

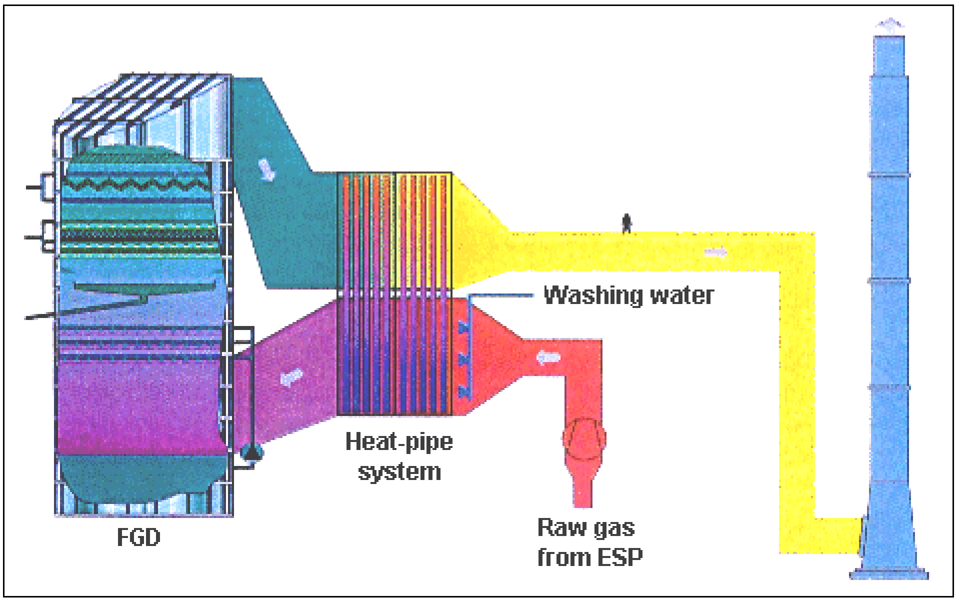


Figure 4.20: Heat displacement around the FGD unit
[138, Sandscheper, 2001]

In these gas-gas heat-exchangers, multi-pipe heat extractors are used to transfer the heat from the hot raw gas to the clean scrubbed off-gas. These systems eliminate leakage because it is not necessary to cross the duct outlet with the duct inlet as is the case in the normal regenerative gas heat-exchanger.

Because of the location, only a few power plants in Europe situated close to the coast have applied seawater-scrubbing systems to reduce the amount of SO_2 emitted to the air. Also due to the location of the plant, i.e. close to a town centre, and other special considerations such as the production of a fully saleable by-product, one coal-fired combustion plant has successfully applied the combined DESONOX process.

4.1.9.1.6 Abatement of NO_X emissions

As is the case for SO_2 reduction, almost all the techniques described in Chapter 3 for the de-nitrification of flue-gases (i.e. primary and secondary measures, and even in a few cases both measures in combination) are currently also applied to coal-fired boilers.

Since combustion temperatures for lignite are lower and the humidity of flue-gas is higher compared to hard coal, the NO_X formation is comparably low. For this reason primary measures are sufficient and have so far only been applied to reduce NO_X emissions from lignite-fired LCPs.

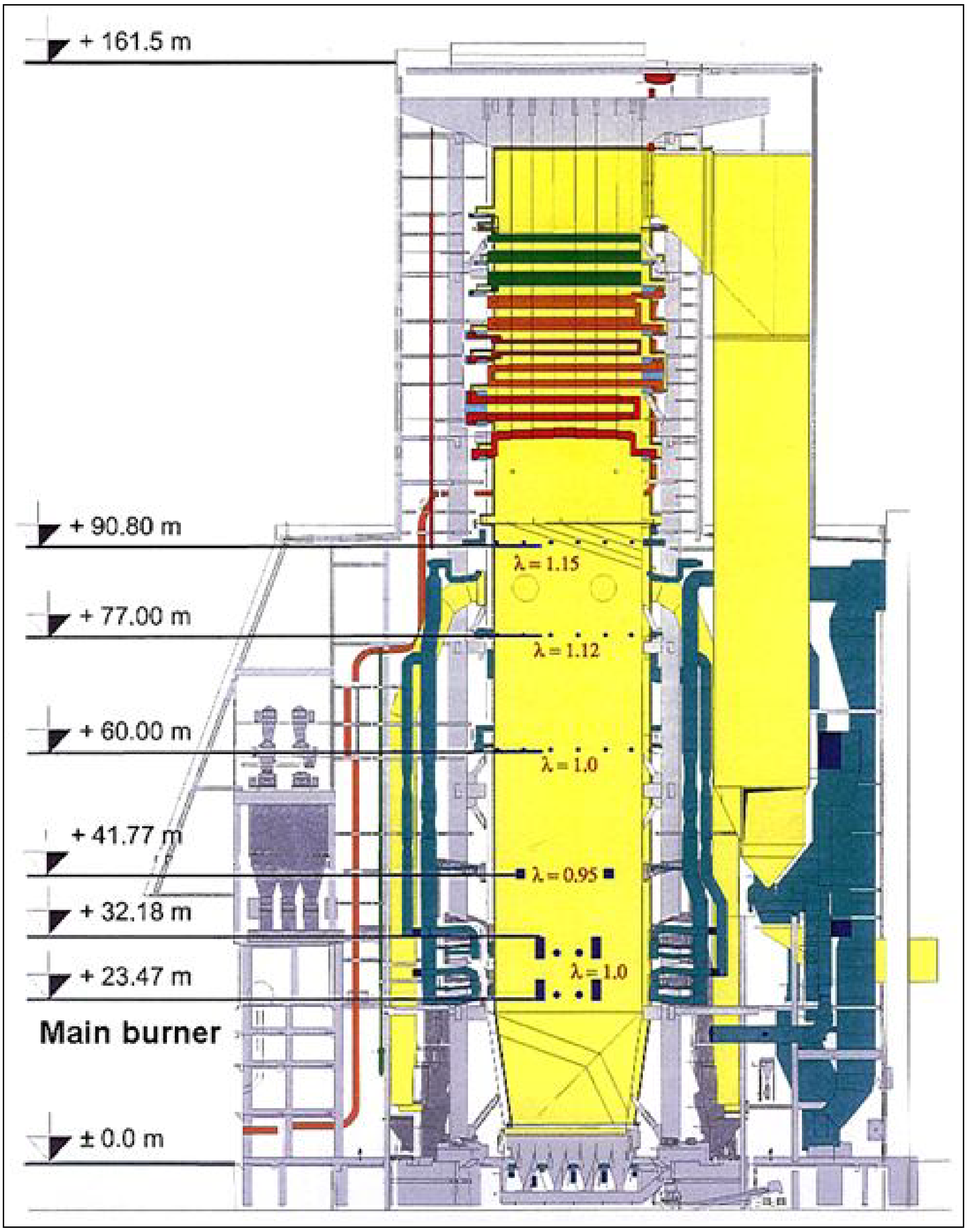
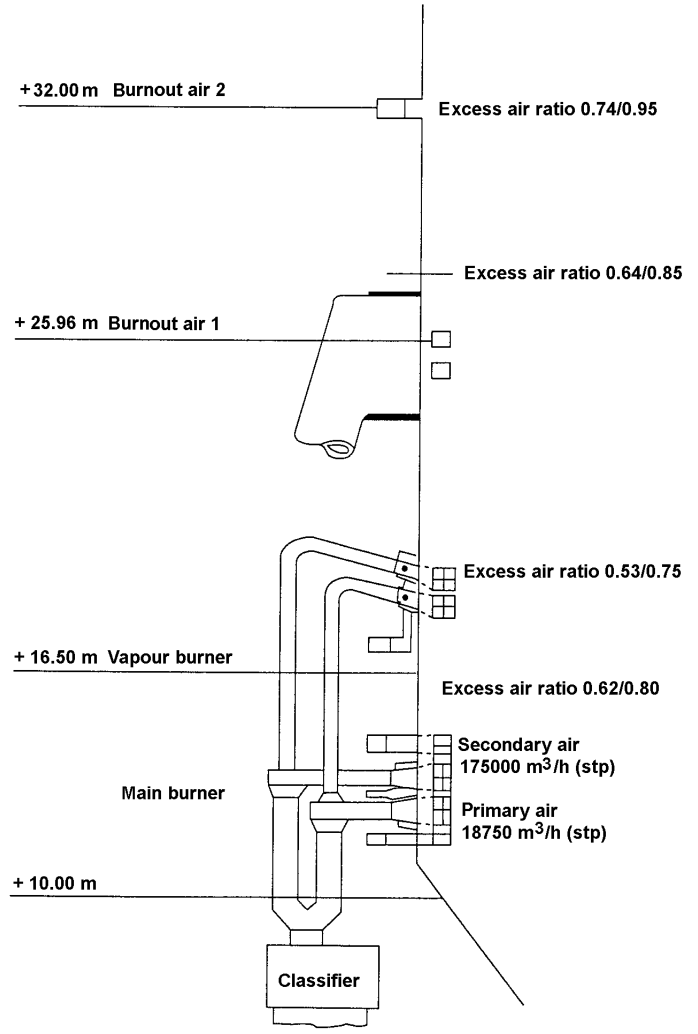


Figure 4.21: Large lignite-fired boiler that has applied primary measures to reduce the generation of NO_X emissions
[92, VEAG, 2000]

For coal-fired boilers that have applied '**low excess air**' as a primary measure, the usual excess air is in the range of 5 – 7 % O_2 (in flue-gas). A low excess air combustion can be characterised by 3 – 6 % O_2, and a corresponding NO_X emission reduction of between 10 and 40 %. Also, residence time has been identified as a key factor in the simultaneous control of NO_X, CO and unburned carbon. The relationship between NO_X, CO, and excess air at various sections in a 150 MW_e boiler is shown in Figure 4.22.



Emission	
NO_X	178 mg/m³
CO	160 mg/m³
O_2	4.9 %
33 m	
NO_2	231 mg/m³
CO	2057 mg/m³
O_2	2.49 %
Temperature	849 °C
29 m	
NO_2	219 mg/m³
CO	7365 mg/m³
O_2	0.35 %
Temperature	1055 °C
23 m	
NO_2	244 mg/m³
CO	7767 mg/m³
O_2	0.83 %
Temperature	1043 °C
16 m	
NO_2	245 mg/m³
CO	11026 mg/m³
O_2	0.70 %
Temperature	1080 °C

Figure 4.22: The relationship between NO_X, CO and excess air at various sections in a 150 MW_{el} lignite-fired boiler
[108, Scott, 1997]

This technique gives better results for wet bottom boilers than for dry bottom ones, for wall fired boilers than for tangential-fired ones, and for hard coal-fired units than for lignite-fired ones.

Flue-gas recirculation: is not used very often in coal-fired boilers, except in wet bottom boilers. For coal-fired boilers, the NO_X reduction obtained with this technique can be as high as 15 – 20 %. This technique is only used in lignite-fired boilers by hot flue-gas recycling for lignite milling. In this case, the flue-gas is extracted for drying the lignite and is, therefore, not primarily used to reduce NO_X emissions, but it is still one of the reasons for the generally lower NO_X formation compared to hard coal furnaces. Often with cold flue-gas NO_X can be reduced further, and additionally slagging can be reduced for low temperature melting ash.

‘Overfire air’ (OFA): is the most commonly used primary measure in coal-fired boilers. With modern OFA designs (optimised nozzle design, separated and swirled airflow), NO_X reductions of 40 – 50 % can be achieved in wall- or tangentially-fired boilers. OFA is a particularly efficient NO_X reduction technique for tangentially-fired boilers, where it can be implemented as ‘close coupled OFA’ (i.e. with the addition of OFA ports just above the highest row of burners). Another option is ‘separated OFA’ (i.e. with the addition of OFA ports above the main combustion zone, separated from the burner rows).

Low NO_X burners (LNBs): for coal-fired boilers, the most often used are air-staged or fuel-staged type burners, with respective NO_X emission reductions of 25 – 35 % and 50 – 60 % respectively. Low NO_X burners are the most common technique used to reduce NO_X emission in both new and existing coal-fired boilers. They constitute a mature technology with many different designs currently available from worldwide suppliers, often specifically adapted to each type and size of boiler.

LNBs are often used in combination with OFA, especially with tangentially-fired boilers, together with tilting or pulverised/coal injectors and various OFA types. NO_X reductions of 50 to 70 % can be achieved.

It has been claimed that modern air-staged LNB designs for wall-fired boilers (with optimised nozzle, or swirl for secondary air injection, and a deflector for secondary/tertiary air injection) can achieve NO_X reductions of up to 50 % without OFA, and up to 70 % with OFA.

In lignite-fired power plants, NO_X emission reductions can be up to 75 % with LNB, OFA and/or flue-gas recirculation.

The implementation of low NO_X burners may increase the level of carbon-in-ash, which should be kept within a limit so as not to jeopardise the management of these combustion residues. The addition of classifiers to the coal mills, which improves the fineness of the pulverised coal, is an efficient way to counterbalance this problem. Some modern coal LNBs are efficiently designed so as not to influence the carbon-in-ash level.

Reburning in coal-fired boilers: this is implemented with coal – or far more commonly – natural gas as reburning fuel. Gas is used far more often than coal. Reburning is easier to apply to new power plants but it has also been successfully adapted to existing units.

Gas reburning has recently been implemented in several wall, tangential, or cyclone coal-fired boilers in the US (from 33 to 600 MW_e). The gas reburning technique has only been installed in units already equipped with low NO_X burners and/or OFA. The corresponding NO_X reduction can be up to 40 – 50 % of the NO_X level achieved with low NO_X burners and/or OFA, which is around a 65 – 75 % reduction from the original NO_X level (for a reburn fuel representing 15 to 20 % of the total heat input).

An ‘advanced gas reburn’ technique (AGR), mixing regular gas reburning with injection of a nitrogen agent (ammonia or urea, see SNCR paragraph for details), has also been installed in one coal-fired boiler. This promising technique has been claimed to have achieved a NO_X reduction of up to 85 % from the initial NO_X level, but it is not yet proven technology.

SNCR and SCR: are secondary measures which have largely been applied to coal-fired combustion plants. In Europe, SCR systems are particularly applied in Austria, Germany, Italy, and the Netherlands. Outside of Europe they are mostly applied in Japan and the US. The SCR technology has proven to be successful for hard coal-fired power plants, but has not yet been applied to lignite-fired plants. In a few cases where an SCR system has been applied to lignite-fired power plants, it was shown that the catalyst’s lifetime was too short, because of the high quartz content in the ash which causes high abrasion of the catalyst. In addition, lignite typically contains a lot of water and ash, and their combustion is generally at a sufficiently low furnace temperature to achieve emissions of 200 mg/Nm^3 without the need of SCR.

In utility boilers, the SCR is normally placed between the economiser and the air preheater (high-dust configuration) to enlarge the temperature window in order to minimise costs. For pulverised fuel combustion SCR, high dust does not principally need a by-pass for start-up and shut-down, but ammonia injection has to be limited to temperatures above a minimum temperature. Tail-end configurations in which the catalyst is placed downstream of the air preheater require the flue-gas to be reheated to the catalyst operating temperature and are, therefore, more expensive to build and operate. Required SCR retrofit components include the SCR reactor, associated ducting and structural work, the ammonia storage and distribution system, and controls. Other components which may be necessary include an economiser bypass and sootblowers.

The choice of the catalyst type and characteristics depends on the ash mass flow and its erosive potential (plate type, honeycomb type). High dust loadings require, therefore, catalysts with high plugging and abrasion resistance. Medium-pitch honeycomb SCR catalysts are favoured for low-dust applications where nearly all the fly ash has been removed from the flue-gas. The increased surface area resulting from the use of medium-pitch honeycomb SCR catalysts in low-dust applications results in lower catalyst volumes compared to high-dust applications.

The issues of boiler type and coal composition factor significantly into the catalyst design and must be specifically considered for each individual coal plant. Slag-tap (WBB) furnaces with fly ash recirculation generally show a higher catalyst deactivation rate compared with dry-bottom boilers. Coals high in arsenic, alkaline or alkaline-earth metals, phosphorus, calcium and a number of other compounds show higher catalyst deactivation behaviour, which must be taken into consideration, when catalyst lifetime and loading volumes are calculated. The sulphur content in the coal must also be examined to determine an appropriate SO_2 to SO_3 conversion rate for the SCR catalyst and to establish a minimum operating temperature at which the formation of ammonium bisulphate can be avoided.

The catalyst lifetime can be optimised through proper maintenance, including the use of appropriate sootblowing and by avoiding contact with moisture for catalysts exposed to fly ash. System bypasses should be used when catalysts are not in operation or if the economiser temperature drops below the minimum catalyst operating temperature at low boiler load.

4.1.9.2 Control of emissions from fluidised bed combustion

For fluidised bed systems, fuel is used coarsely ground. In circulation fluidised bed combustion systems (CFBC), the bed zone is expanded by higher airflow velocities and ash (necessary for this type of combustion) has to be recirculated through a cyclone which is an integral component of CFBC to recover coarse particles.

4.1.9.2.1 Dust abatement

For dust abatement from fluidised bed combustion (FBC) boilers, both ESPs and fabric filters are currently applied.

4.1.9.2.2 Abatement of SO_2 emissions

As already mentioned, FBC boilers can operate very efficiently in terms of SO_2 removal, for example 80 – 90 % for BFBC and more than 90 – 95 % in a CFBC boiler. In FBC boilers, lime or limestone is added directly to the fuel and injected into the fluidised bed. These additives support the natural capability of alkaline ashes to capture SO_2. Good desulphurisation is achieved by adding limestone with a Ca/S ratio of 1.5 to 3.5. Beside the Ca/S ratio, the bed temperature also plays an important role in ensuring effective SO_2 reduction. Since the calcination process begins at around 700 °C and improves with higher temperatures, the most favourable combination of calcination and sulphation occurs at about 840 °C.

The system used for sulphur reduction in FBC boilers is simple to operate, i.e. feeding of the sorbent and removal of the reaction product are incorporated into the combustion process and a separate reactor is not needed.

To achieve an almost 100 % SO_2 absorption, the mass of calcium oxide in the bed must be in excess of what is required for stoichiometric conditions. This overdosing results in an increase of NO_X emissions, especially in CFBC boilers, because CaO catalyses the reactions of nitrogen compounds. However, the greatest increase does not take place until the SO_2 concentration is very low.

The principle of the fluidised bed combustion comprises an integrated environmental protection capability. Sorbent injection into the FBC boiler is an inexpensive method for sulphur capture. Investment costs are low, because the desulphurisation is incorporated into the combustion process and separate reactor equipment is not needed. Secondary measures for desulphurisation are not yet very common, but have already been used occasionally in a few FBC combustion plants.

The largest operational expenses are due to the consumption of sorbent and the handling of combustion residues. The by-product of fluidised bed combustion is a mixture of ash, $CaSO_4$, unburned fuel and unreacted sorbent. Relatively large amounts of sorbent are needed to reach a sufficient SO_x absorption; thus the volume of the solid waste from FBC is also large. Up until now, disposal in landfills has been the most common means of handling ash from the FBC boiler at power plants. Also the ash can be used for construction purposes, such as in a road base or as a structural fill, providing there is not too much calcium in the ash.

An increased dust load may result in a need to enlarge the dust precipitator. The benefits of this kind of investment have to be evaluated separately on an economic basis.

4.1.9.2.3 Abatement of NO_X emissions

The low combustion temperature (between 850 and 950 °C) of fluidised bed combustion systems is advantageous for the suppression of NO_X emissions. However the FBC boilers generate a significant proportion of the NO_X emissisn as N_2O which has a high global warming potential. But this is not the only way to reduce NO_X emissions in FBC boilers, for example, other techniques such as SNCR systems are applied in some plants in the US. However, with the desulphurisation improvement by adding limestone, any unreacted lime catalyses the conversion of NH_3 to NO_X.. This means, that the more lime (for SO_X control) that is added to the fluidised bed, the more NO_X is formed.

Different types of fluidised bed combustion, usually BFBCs, are used in smaller capacity LCPs and tend to have higher NO_X emissions.

4.1.9.3 Control of emissions from grate firing

When burning coal or lignite in grate combustion systems, most of the ash is left on the grate and collected as bottom ash. Only a small quantity of ash leaves the furnace as fly ash and must be collected in the dust reduction devices.

4.1.9.3.1 Dust abatement

For dust abatement from grate-fired combustion plants, both ESPs and fabric filters are currently applied.

4.1.9.3.2 Abatement of SO_2 emissions

For grate firing, which is mainly applied to smaller (<100 MW) industrial combustion plants, low sulphur fuel is mostly used for SO_2 control. Because the combustion temperature varies between 850 and 950 °C, therefore additives such as lime or limestone can also be added directly to the fuel for SO_2 capture. These additives support the natural capability of alkaline ashes to capture SO_2. $CaSO_3$ becomes unstable at temperatures greater than 850 °C, and CaO and SO_2 coexist in chemical balance. For this reason, grate combustion is not as effective for the abatement of SO_2 emissions.

4.1.9.3.3 Abatement of NO_X emissions

The low combustion temperatures of grate systems are advantageous for the suppression of NO_X emissions. In this context, it should be stressed that grate systems (without additional control measures) emit about 300 mg/Nm^3 of NO_X, which is much less than from an uncontrolled hard coal burning pulverised combustion plant. Overfire air is also sometimes used in addition to reduce the generation of NO_X emissions.

4.1.10 Water and waste water treatment

A variety of waste water types (see Chapter 1) is generated by operating coal- and lignite-fired combustion plants. The techniques described for waste water treatment in Chapter 3 are applied to a large extent for the purification of waste water from coal- and lignite-fired plants.

Managing the run-off water from coal yards, slag piles and by-product storage needs special attention. Before discharging surplus water it must be safeguarded by treatment and monitoring so that the applicable pollution limits are met. Dilution by fresh water to meet the limits is not acceptable.

4.1.11 Combustion residues and by-products treatment

When coal is burned, most of the mineral matter is captured and removed as solid material at various places in the system, such as at coal mills, at the bottom of the boiler, in the economiser flue-gas cleaning system and in the stack. Bottom ash is recovered from all types of coal- and-lignite-fired combustion plants, although the percentage of total ash it accounts for varies. Because of the recycling of fly ash in wet bottom boilers, 100 % is recovered as slag tap granulate. Only when a certain amount of unburned fuel remains in the fly ash, is it recovered separately and stored in a special silo. With circulating fluidised bed combustion, a cyclone precipitator returns most of the ash to the furnace, where it agglomerates to bed material and is recovered as bottom ash.

With lime/limestone based wet FGD systems, gypsum is recovered with a definite crystalline structure. This is necessary to separate gypsum from smaller undissolved limestone particulates and to dry the recovered gypsum. Too small particulates increase the humidity of this by-product, normally by about 10 %. When this by-product is washed, a high quality marketable product (comparable or better than natural gypsum) can be achieved, with only trace impurities giving any indications of the fuel from which it is derived. In most cases, gypsum is collected and stored in closed stockpiles. In some plants, gypsum is dried further down from 10 to 4 %, or even down to 1 %, to reduce transport costs and to increase the consumption quality.

Figure 4.23: Closed gypsum storage facilities
[94, Umwelt + Technik, 2000]

In cases where there is no market potential for gypsum, FGD gypsum is landfilled in a controlled manner in the same way as the fly ash and wet ash. Separate landfilling of either by-product is possible, but it has been found that mixing FGD gypsum with fly ash and FGD waste water produces a mixture, often called 'stabilizate', which has better landfill properties than that of each component alone. These properties are: mechanical strength, permeability, and leachability.

The most usual management of the residues and by-products from lignite combustion, is as landfill for the restoration of exhausted open-cast lignite mines. Fly ash is, also, very often used as a material for strengthening the overburdened slopes during the exploitation of lignite mines.

'Stabilizate' performs well, because it combines the pozzolanic properties of the fly ash, as well as its potential for binding heavy metals and trace elements, with the properties of gypsum. No adverse environmental impacts are observed from the controlled landfills of LCP solid by-products.

In general, combustion residues and by-products such as ashes and FGD by-products are collected at various points such as the boiler, de-dusting hoppers, ESPs, fabric filters and FGD plants. These materials are transported by means of hydraulic or mechanical devices and stored in closed silos or in especially designed storage buildings, like those used for the storage of gypsum from the FGD plant.

Table 4.2 shows a summary of the possible re-use options of the residues and by-products from coal-fired power plants. It has to be determined on a case-to case basis, which possibility should be carried out.

	Fly ash		Bottom ash		Sorption process products	Gypsum
	lignite	Hard coal	lignite	Hard coal		
Construction industry						
Concrete additive (disregarding ‘Flual’)	x	x				
Lightweight aggregates for concrete	x	x	x	x		
Foam mortar, porous concrete	x	x			x	
High performance concrete	x	x				
‘Flual’ production	x					
Blend additive in the cement industry	x	x				
Raw meal constituent in the cement industry	x	x				
Cement additive to delay setting					x	x
Isolation walls	x	x			x	
Construction gypsum						x
Ceramic industry	x	x	x	x	x	
Road building and landscaping	x	x	x	x		
Dam construction with the RCC (Roller Compacted Concrete) technique	x	x	x	x		
Filler for bituminous surfacing, bonding layers and sub-base binders	x	x				
Ground stabilisation, loose building materials for earth work and road construction	x	x	x	x	x	
Sound proofing		x		x	x	
Landfill technology, waste treatment	x	x	x	x		
Landfill	x	x	x	x	x	x
Hazardous substance immobilisation	x	x				
Lining material for landfill bottom lining	x	x			x	
Surface filter for landfill sealing			x	x		
Sewage sludge conditioning					x	
Base material for biological waste water cleaning			x	x		
Filler for pipeline ditches						
Stabilised ash cement mixture	x	x			x	
Ditch filling	x	x			x	
Other methods of utilisation	x	x	x	x		
Reclamation material in mining	x	x	x		x	
Zeolite production	x	x				
Alpha- and beta-half hydrate production						x
Filling material in the paper industry					x	x
Production of anhydrite					x	
Müller-Kühne-process’	x	x	x	x	x	x
Thermal recovery			x	x		
Flue-gas desulphurisation					x	

Table 4.2: Examples of re-use of residues and by-products from coal and lignite combustion [64, UBA, 2000]

4.2 Examples of applied processes and techniques

This part of Chapter 4 provides a number of examples of techniques and processes currently applied in different coal- and lignite-fired combustion installations. The aim of the examples is to demonstrate how specific techniques have been applied to new or retrofitted plants in order to ensure a high level of protection for the environment as a whole, taking into account, in each case, the particular site-specific conditions and environmental requirements. However, from the information collected, it is not always clear, if or how each technique described in the examples has been assessed against the definition of BAT given in article 2 (11) of the Directive, as well as against the list of 'considerations to be taken into account generally or in specific cases when determining the best available techniques bearing in mind the likely costs and benefits of a measure and the principles of precaution and prevention' and, consequently, how the technique has been selected and applied. Furthermore, it cannot be assured that the environmental performance presented is constant and continual under all operational conditions, over which time period, whether any problems have been encountered, and what the cross-media effects are. Also, it is not always clear what the driving force is for applying the technique and how the costs and environmental benefits are related in each case. Therefore, the information provided in the following examples is meant only to provide general indications of reported current practice and cannot be considered as appropriate reference points. The techniques that are given as examples arise from information provided and assessed by members of the Technical Working Group as part of the information exchange of LCPs.

4.2.1 Examples of individual applied techniques

EXAMPLE 4.2.1.1 ULTRA LOW NO_X TANGENTIAL-FIRING SYSTEMS (ULNTF) FOR BITUMINOUS COAL

Description: The concept of the modern ultra low NO_X bituminous coal tangential firing system is characterised by a superposition of radial and axial air staging. The combustion occurs under sub-stoichiometric conditions. Here, air is supplied in various stages in a vertical direction. By means of the radial air staging, a zone with a high O_2 and a low CO content is created in the outer area of the furnace. This leads to an effective protection of the furnace walls from corrosion (Figure 4.24).

The burners are installed in the corners. Each mill supplies pulverised fuel to one burner level. Above the top burner level, overfire air nozzles are arranged in the furnace walls at a significant distance from the top burner level, to allow NO_X reducing reactions. The arrangements and dimensions of the overfire air nozzles are chosen in such a way that the quantity of overfire air is distributed well over the furnace cross-section to maintain efficient combustion. Each individual burner consists of one or two fuel nozzles, a rectangular offset air nozzle, a rectangular intermediate air nozzle (in this case, there are two fuel nozzles) and two circular upper and lower air nozzles. These nozzles are used for the oil burners during start-up of the unit. The offset air nozzles are installed above each burner. They are directed towards the furnace walls to create a layer of air at the furnace walls. All other fuel and air nozzles, except the overfire air nozzles, are directed to the tangential circle (Figure 4.24).

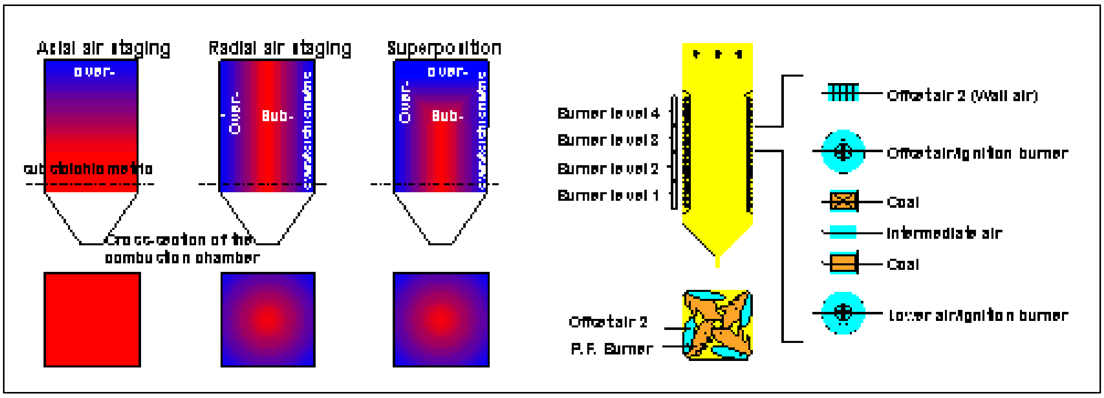


Figure 4.24: Principle of axial and radial air staging

Achieved environmental benefits: The NO_X emissions, which can be achieved as a function of the burner level stoichiometry, are shown in Figure 4.25. As can be seen in this figure, NO_X emissions in the upper stoichiometry range are reduced significantly with a decrease in the burner stoichiometry. However, NO_X emissions peak below a stoichiometry of 0.80.

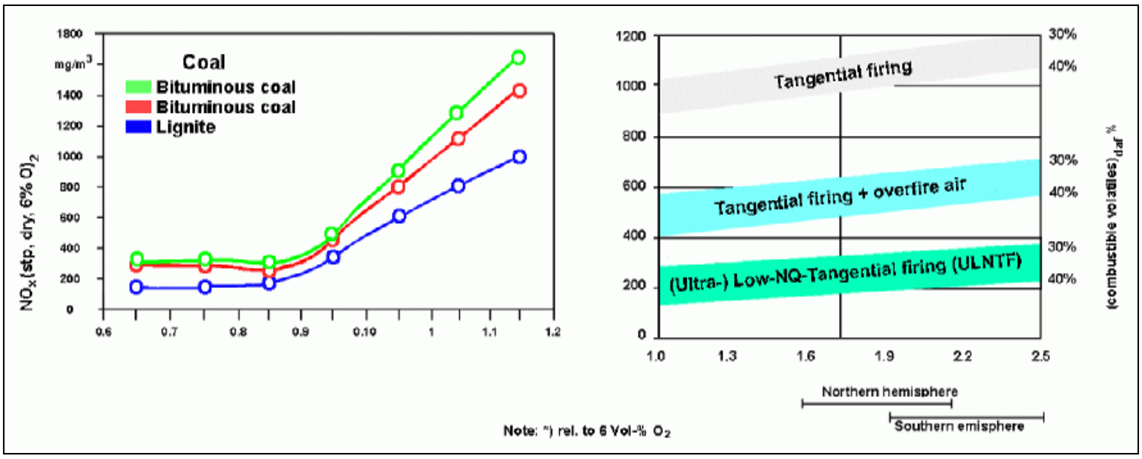
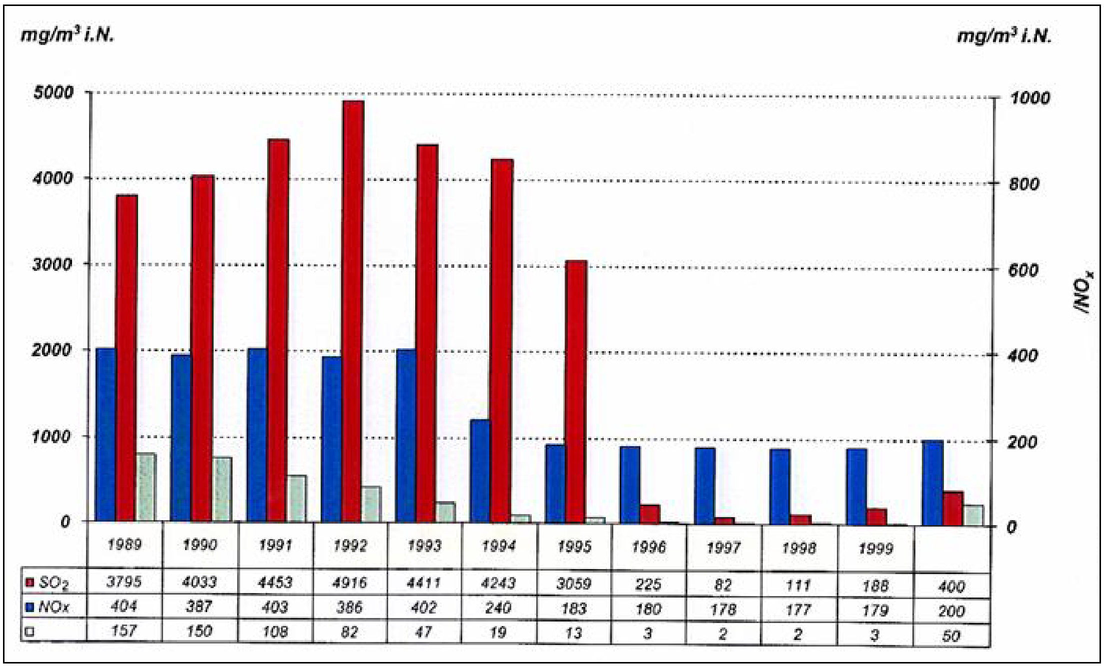


Figure 4.25: NO_X versus burner stoichiometry and firing system

Parallel to the NO_X emissions measurements, CO and O_2 are checked in the vicinity of the furnace walls. Only very low CO concentrations and high O_2 concentrations are measured at the walls with the ULNTF firing system during ultra low NO_X operation. Figure 4.25 also shows a comparison of the ultra low NO_X T-firing system ULNTF (with offset air and overfire air level) with the low NO_X firing system (with overfire air level) and with the basic firing system for bituminous coal regarding NO_X. The figure shows the NO_X reduction potential of the ultra low NO_X firing system for all bituminous coals from the world market. Figure 4.26 shows a comparison of the NO_X values for some selected power plants (labelled as A to M).



	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	
🟥 SO_2	3795	4033	4453	4916	4411	4243	3059	225	82	111	188	400
🟦 NOx	404	387	403	386	402	240	183	180	178	177	179	200
☐	157	150	108	82	47	19	13	3	2	2	3	50

Figure 4.26: Comparison of the NO_X values for some selected power plants

Applicability: Limited experience is available with ultralow NO_X tangential firing systems, and these can, in general, be applied to new plants and retrofitted to existing plants.

Cross-media effects: No potential effects.

Operational data:

- the reduction of excess air and exhaust gas temperatures leads to an improvement of the steam generator efficiency. Additionally, the efficiency increase makes an important contribution towards the reduction of the CO_2 emissions
- the reduction of the NO_X content in the flue-gas leads to a decrease in the ammonia consumption for the catalyst and an increase of the catalyst service life (if the catalyst is available)
- improvement of the steam generator efficiency, reduction of the power consumption of induced-draught, forced-draught and FGD fan all result in an improvement in the net efficiency of the power station unit.

Economics:

- improvement of the steam generator efficiency
- increase in the net power output
- no additional operating costs.

Driving force for implementation: Requirements for low NO_x emissions from national/European legislation and/or an increase in boiler efficiency and a decrease in fuel consumption.

Reference literature: [114, Alstom, 2001], [115, Epple, et al., 1995], [116, Kather, 1996], [117, Marx, et al., 1997], [34, Verbund, 1996].

EXAMPLE 4.2.1.2 PRIMARY MEASURES TO REDUCE NO_X FROM VERTICALLY FIRED SYSTEMS WITH FUEL PREHEAT AND CYCLONE BURNERS INTEGRATED WITH AN OFA SYSTEM

Description: In the 1920s, the preferred pulverised coal (PC) furnace system was vertically (arch) fired, because this could achieve flame stability, by admitting some secondary air through openings along the vertical wall underneath the arch. Later on, the adoption of ‘turbulent’ burners, requiring only swirled secondary air surrounding the primary air/coal nozzle, allowed the application of horizontally fired PC furnaces in most cases. However, PC firing of anthracite without support fuel still requires the progressive supply of secondary air, which is characteristic of arch firing (AF). Favourable characteristics of anthracite coals are the low sulphur content, they are found worldwide, and the extensive reserves in East Asia.

The most successful AF technology has kept the same high (~70/30) flowrate ratios of vertical-wall-air/arch-air of the early vertically fired systems. Furthermore, its burners are shaped as cyclone separators for venting air from the primary air/coal mixture. This further favours unsupported ignition, achieved even with coals having less than 5 % volatile matter. More meaningful from the ignition standpoint is the hydrogen content of the fuel, which with this AF technology can be as low as 1.5 % for unsupported firing at full load. With higher volatile coals, AF units have attained NO_X emissions at the low level of the most advanced low NO_X horizontally fired burners. However, it is important to note that previous designs for NO_X reduction with air staging in the burner and furnace have targeted only the fuel nitrogen released during coal devolatilisation.

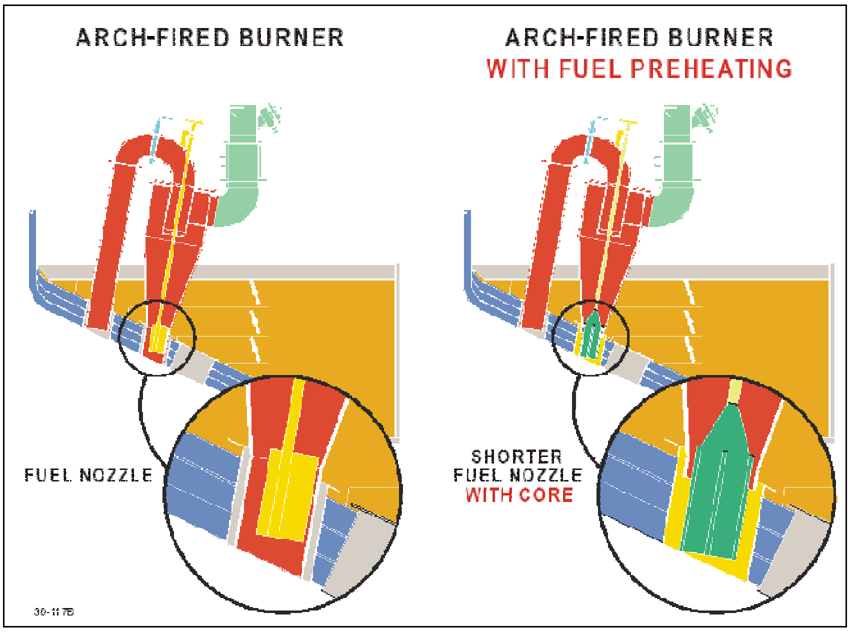


Figure 4.27: Arch-fired burner with fuel preheat
[192, TWG, 2003]

Figure 4.27 shows the standard arrangement of an AF cyclone burner, with a detail enlargement of the fuel nozzle. The figure illustrates the fuel preheat modification which improves the flame stability. The modification involved making the cylindrical fuel nozzle shorter, to allow mixing of cold air/coal with the hot air surrounding the nozzle, and inserting a ‘core’ in the nozzle that enhances the venting capability of the cyclone whilst maintaining the air momentum for proper flame penetration. A further modification may be for the vent of the AF cyclone burner to be integrated with an overfire air system. Here, the vent will convey most of the coal moisture and the finest of the PC in a very lean phase, made even leaner by the OFA.

An unavoidable consequence of NO_X reduction primary measures is an increase in unburned fuel (unburned carbon). Retrofitting a more efficient classifier of the mill product can counter this increase in unburned fuel. A related component of this NO_X reduction technique involves using an adjustable static classifier instead of the baffle classifier of the tube or ball mill, which is preferred for pulverising anthracite. Both types of classifiers are an integral part of the ball mill. The adjustable static classifier is designed as a cyclone with multiple inlets, that are defined by adjustable vanes.

Achieved environmental benefits: The coals defined in Table 4.3 were tested at a US 22 MW_{th} AF Combustion and Environmental Test Facility (CETF), including a blend of Pennsylvania, US coals. With the fuel preheat modification, a stable combustion was achieved with every coal tested, even at 50 % load. For a given NO_X, the corresponding unburned fuel was reduced by each modification. With the fuel preheat and vent-to-OFA modifications, over 50 % reduction of NO_X meant less than doubling the unburned fuel. The trends resulting with the other coals tested were similar, particularly when operating with OFA.

	Analysis % by weight							**HHV**[c]	**HGI**[d]
Coals (ASTM Group)	VM[a]	Ash[a]	H_2O[a]	C[b]	H[b]	N[b]	S[b]	kcal/kg	
50/50 blend (~semi-anthracite)	13.5	11.	9.1	72.9	2.9	1.4	1.	7530	68
Kocher, Pennsylvania (anthracite)	6.9	11.3	11.5	72.4	2.1	1.0	0.7	7220	42
Carbonar, Spain (anthracite)	5	19.5	7.6	68.5	1	0.7	0.7	7140	43

a Proximate analysis: =volatile matter (VM) ash and total moisture (H_2O)
b Ultimate analysis: elements as shown
c Higher heating value
d Hardgrove grindability index.

Table 4.3: Analysis of different test coals

Two of the 16 burners of an European 154 MW_e AF unit firing anthracite have undergone the fuel preheat modification. During testing with a local coal of 5 % volatile matter, 1 % hydrogen content (Carbonar, Spain Table 4.3), the modified burners were able to operate without support oil in them or in burners next to them, even at the 60 % minimum technical load.

Two US AF utility (central power station) units, each 300 MW_{th} input, firing anthracites with 7 % volatile matter high moisture and ash content, restarted in the Spring of 2002 after retrofitting the preheat nozzle and vent-to-OFA modifications. As a result, these primary (in-furnace) measures amply met the two 300 MW_{th} utility units commercial guarantee of bringing the pre-retrofit NO_X level, (~950 – 1180 mg/Nm^3) down to (~510 mg/Nm^3). In fact, this new PC firing system ranks among those resulting in the lowest NO_X emissions, in spite of having so far fired only coals with very low volatile matter. Secondary (back-end) measures to further reduce NO_X based on the safer urea could be adopted, because with this technique, the CO kept well below the typical 100 ppm limit that urea needs, can easily decompose into the reacting ammonia.

Retrofitting the adjustable static classifier in the six ball mills of an European 330 MW_e AF unit firing anthracite has reduced the amount of unburned fuel by over 50 %.

Applicability: The use of the preheat nozzle and vent-to-OFA technique is suitable for new plants of more than 30 GW_e and for existing AF units in the US, Europe and East Asia, ranging in size up to 717 MW_e.

Cross-media effects: The preheat nozzle and vent-to-OFA technique reduces the costs of the application of secondary measures. For fuels having less than 1.5 % hydrogen content, this technique saves the support oil or coal having a higher volatile matter content, and either one being co-fired for flame stability. When combined with the adjustable static classifier, it avoids the cost and external issues associated with increased fuel consumption.

Operational Data: No substantial change, except for reduced NO_X and increased fuel flexibility, as noted.

Economics: The preheat nozzle and vent-to-OFA retrofit costs are in the order of those mentioned in the literature for NO_X reduction by primary measures in wall or opposed firing boilers. The adjustable static classifier initial cost is a fraction of the cost of the dynamic classifiers and has negligible operating and maintenance costs, while it also counters the increase in coal consumption subsequent to implementing NO_X reduction modifications.

Driving force for implementation: Lower emission limit values for NO_X**.** Besides this, the 'Clean Development Mechanism' of the Kyoto Protocol should create opportunities to retrofit existing units in East Asia.

Reference Literature: [172, Garcia-Mallol, et al., 1999], [173, Garcia-Mallol, et al., 2000], [174, Garcia-Mallol, et al., 2002].

EXAMPLE 4.2.1.3 GAS-OVER-COAL AND COAL-OVER-COAL REBURN TO REDUCE NO_X EMISSIONS IN UTILITY BOILERS

Description: The reburn process is an in-furnace combustion modification technique for the reduction of NO_X emissions from large utility boilers. A detailed description of the reburning process is presented in Section 3.4.1.5 of this document.

Achieved environmental benefits: The reburn process has been shown to be effective in reducing NO_X emissions from large pulverised coal-fired plants. This process has been demonstrated within Europe at large coal-fired power plants in the UK (Scotland) (600 MW_e, gas-over-coal reburn) and at a power station in Italy (320 MW_e, coal-over-coal reburn), with NO_X reductions of 45 to 60 % being achieved (compared to emissions when operating with low-NO_X burners alone).

From a baseline emission level of 650 mg/Nm^3 at 6 % O_2, the NO_X emissions from a unit with reburn installed would, therefore, be in the order of 325 mg/Nm^3 (at 6 % O_2).

The performance depends on the available residence time in the furnace – lower emissions are achievable with longer residence times, but conversely shorter residence times will limit the NO_X reduction that can be realised.

Applicability: The reburn process is very attractive for new boilers but, given its need for large chambers, it is likely to be less appropriate for retrofit situations. Ideally the furnace will have a long available residence time so that the optimum performance can be achieved, which is especially important for coal-over-coal reburning. However the process can also be applied to compact furnaces. Here, although there will invariably be some compromise with regard to NO_X and/or carbon-in-ash, experience to date shows that significant NO_X reductions can still be achieved. In principle, therefore, the process is applicable to all large pulverised coal-fired boilers (i.e. 500 MW_{th} and above).

Gas-over-coal reburn can only be applied to sites where natural gas is available at a competitive price.

Cross-media effects: The introduction of reburn gives rise to the possibility of an increased level of carbon-in-ash, and in some instances, this may render the fly ash unsaleable (e.g. for use in cement manufacture), therefore leading to increased landfilling. In practice however, the increase in the carbon-in-ash level has been acceptable (and is still considerably less than that arising from furnace air staging). At the plant in the UK (Scotland), the carbon-in-ash level was similar to baseline levels, whilst at the Italian plant it was higher by a factor of 1.25. When considering the potential application of reburning to a specific plant, the potential increase in carbon-in-ash is of key interest. Measures to minimise the potential impact on burnout include improving the pulverised coal fineness (e.g. by mill upgrades and/or classifier improvements), and increasing the effective residence time in the burnout zone (e.g. by trading off NO_X reduction vs. burnout).

Reburning can also give rise to a reduction in the thermal efficiency of the boiler, both as a result of the increased carbon-in-ash (see above) and, in the case of gas-over-coal reburning, as a result of the increased moisture loss when a proportion of the thermal input is obtained from natural gas instead of coal. Experience in the UK (Scotland) and in Italy has shown that any worsening of the thermal efficiency is only small and can be predicted.

Operational data:

- **gas-over-coal reburn:** NO_X emissions of between 250 and 300 mg/Nm^3 at 6 % O_2 have been achieved, representing a reduction of 60 % from baseline levels. The carbon-in-ash level was not significantly increased over the baseline level. The boiler performance was also not adversely affected. Thermal efficiency was reduced by 1 % due to the increase in the moisture loss arising from the substitution of 20 % of the coal by natural gas
- **coal-over-coal reburn:** NO_X emissions of between 300 and 370 mg/Nm^3 at 6 % O_2 were achieved from a wide range of world traded coals (e.g. Colombian, South African), with there only being a small increase in the carbon-in-ash level (a factor of 1.25 times the baseline level). There was no significant impact on the boiler operation, and the thermal efficiency was practically unchanged.

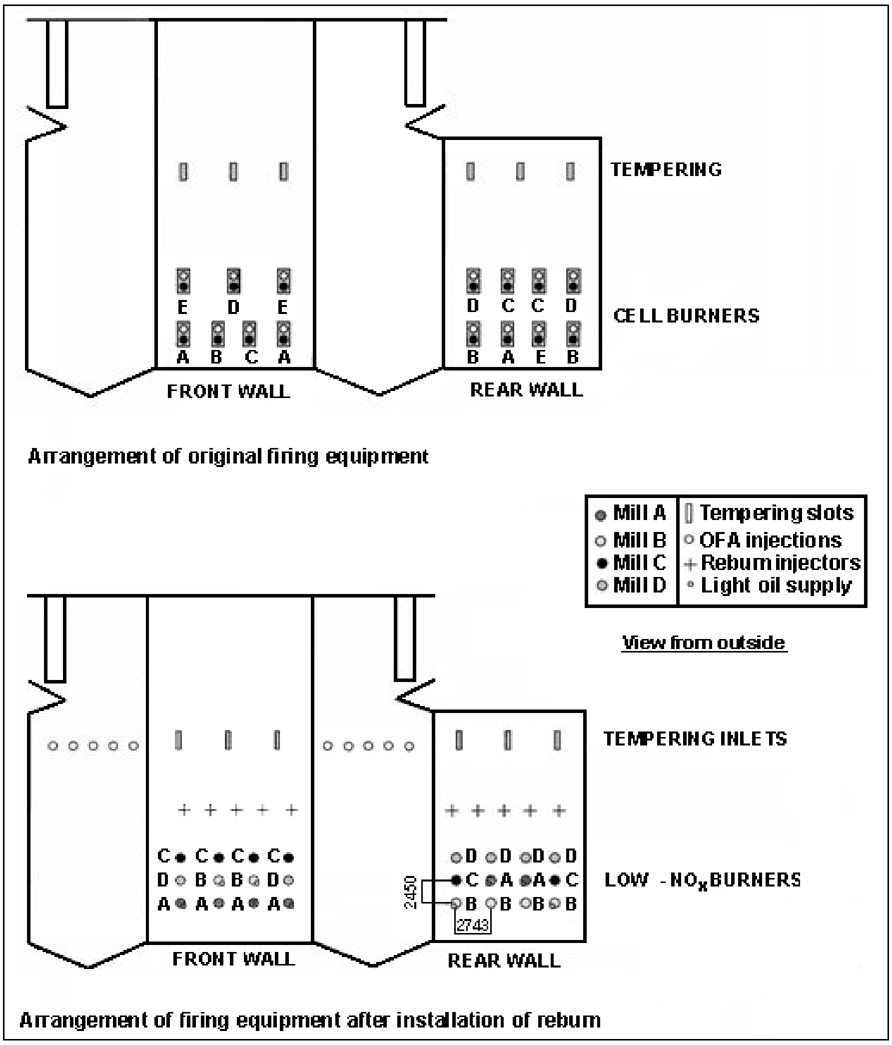


Figure 4.28: Changes in the existing boiler when applying coal-over-coal reburning

Economics: The costs of installing the reburn process are highly site-specific, and in general are dominated by the requirement (or otherwise) for a flue-gas recirculation system. Other considerations include the extent to which the milling classification hardware needs to be upgraded, access constraints, control and instrumentation systems, etc. Typically the capital cost of a reburn system will be in the order of EUR 7.8 – 15.6 per kW_e.

For a coal-over-coal reburn system without FGR, any increases in operating costs are small, provided that the carbon-in-ash levels are kept within acceptable limits. The costs typically comprise additional auxiliary power consumption (for dynamic classifiers and OFA fans if installed) and increased maintenance costs for the reburn system hardware.

The requirement for FGR introduces a significant additional electrical demand.

With gas-over-coal systems, the price differential between the reburn natural gas and the main coal supply will represent the largest operating cost for most installations.

Driving force for implementation: The development of the reburn process has been driven by the tightening of NO_X emissions legislation worldwide, and the economic advantages associated with achieving these limits by primary combustion measures rather than through the more expensive secondary measures (such as through selective catalytic reduction).

Reference literature: [65, Golland, et al., 1998], [66, Hesselmann, et al., 2000].

EXAMPLE 4.2.1.4 PRIMARY MEASURES TO REDUCE NO$_X$ EMISSIONS FROM BITUMINOUS COAL FIRING SYSTEMS AT DRY BOTTOM BOILERS – OPPOSED FIRING SYSTEMS WITH LOW-NO$_X$ SWIRL BURNERS (DS BURNER)

Description: In opposed firing, the burners are arranged at several levels on the front and rear walls of the furnace, Figure 4.29. With swirl burners installed, stable ignition and optimisation of the NO$_X$ reduction measures are possible at each individual burner.

The prerequisite for an effective process of NO$_X$ reduction is optimising the fuel preparation. A flexible mill system, with regard to the grinding force and grinding fineness, lends itself particularly well to the combustion of a wide range of fuels and low grade hard coals. Therefore, a modern mill forms an important integral part of the presented modern low NO$_X$ firing system.

The DS type low NO$_X$ pulverised coal burner, shown in Figure 4.29, is the key component of the low NO$_X$ firing system. This burner is basically a swirl burner. To reduce NO$_X$ formation, the burner has a number of extra design features and elements. A swirler is installed in the pulverised coal tube, and a toothed stabilising ring at the outlet. In this way, an early and stable ignition of the flame is achieved at the stabilising ring. Most of the combustion air is fed, as secondary and tertiary air, in a defined manner along air baffle rings to the flame for delayed mixing.

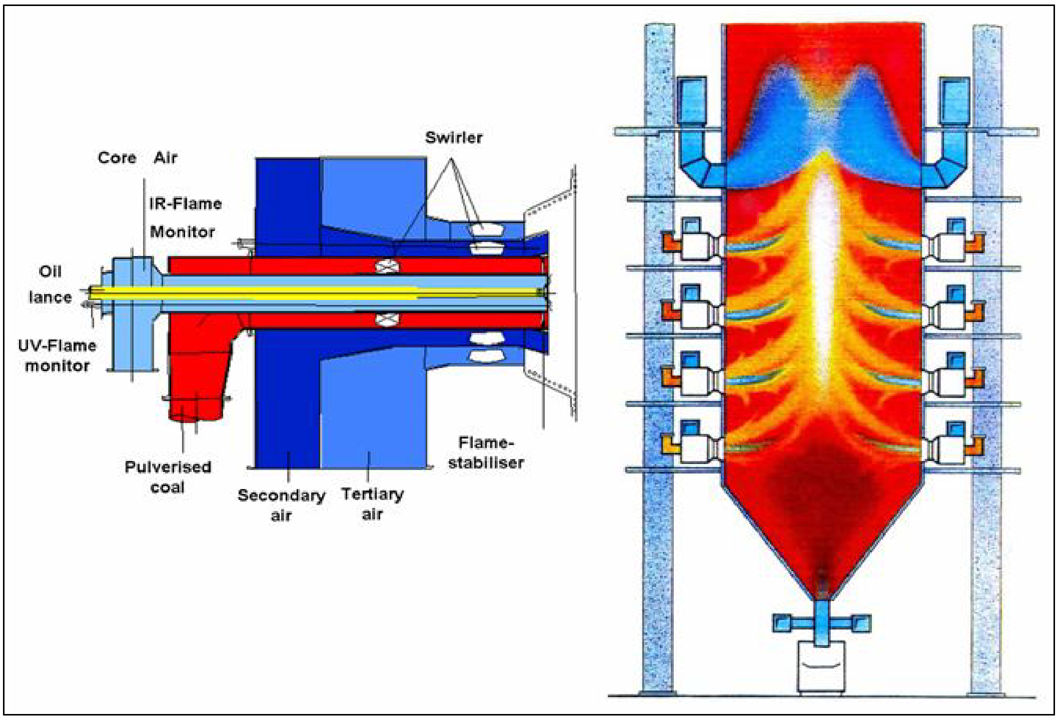


Figure 4.29: DS swirl burner integrated in an opposed fired boiler
[67, EPPSA, 2001]

The combination of low NO$_X$ burners with air staging in the furnace, Figure 4.29, further reduces NO$_X$ emissions. The burners are operated with a near- or sub-stoichiometric air ratio and the remaining combustion air is admitted only after a certain burnout path. The purpose is to reduce the NO, initially formed in the burner zone, in a following reduction zone.

Modern firing systems are operated with low excess air. A typical air ratio at modern plants is 1.15. Operating with low excess air and at the optimum operating mode of low NO$_X$ burners requires a precise setting of the fuel/air ratio at the burners. This is achieved by the uniform distribution of pulverised coal from the mill to the related burners and by controlling the air supply to the burner group which is located at one level and to which fuel is admitted from the mill (or, in extreme cases, air is supplied to each individual burner).

Achieved environmental benefits: In Figure 4.30, the measured NO_X content for a steam generator with a steaming capacity of 530 t/h and with 8 DS burners (thermal capacity of 80 MW) in opposed arrangement has been plotted as a function of the air ratio at the burner, with boiler full load. With the usual operational air ratio of 0.95 and high volatile bituminous coal, NO_X values of around 280 mg/m³ were reached with very stable combustion. Extensive tests regarding the flue-gas atmosphere at the furnace walls showed that, even in the low NO_X operating mode, the oxygen concentrations (>1 %) at the walls are sufficient to exclude furnace-side corrosion.

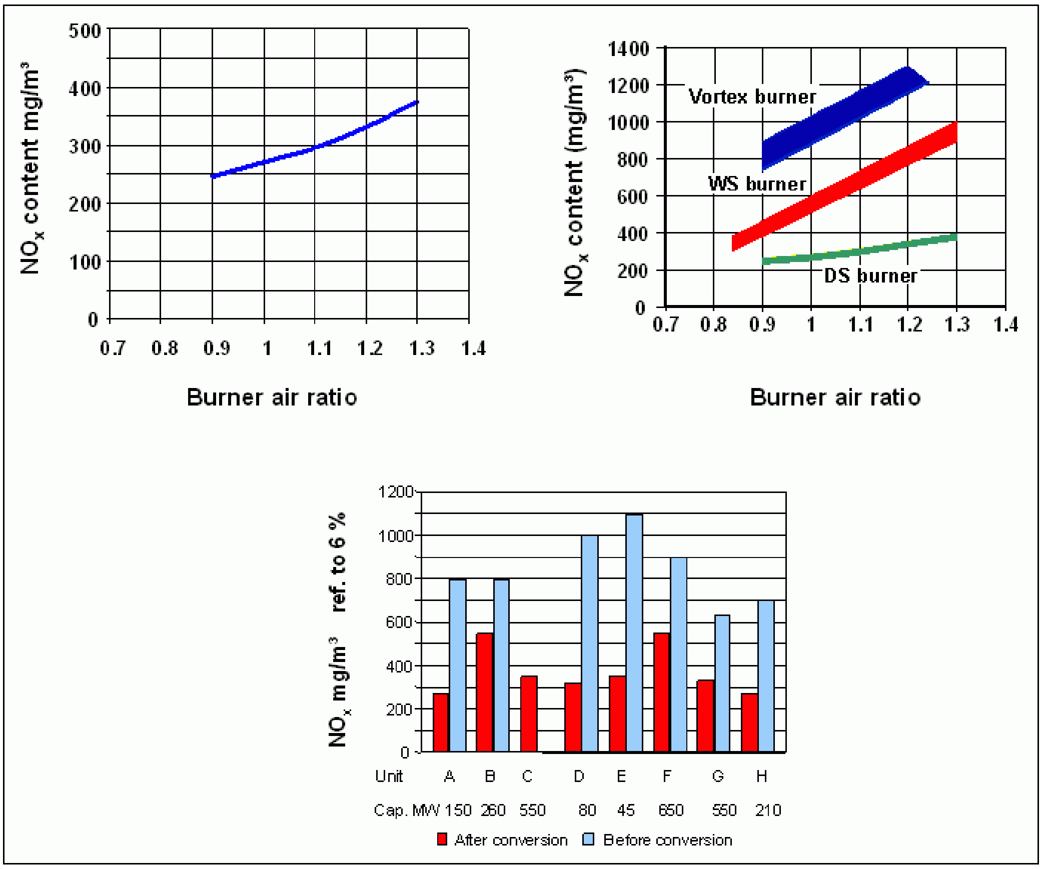
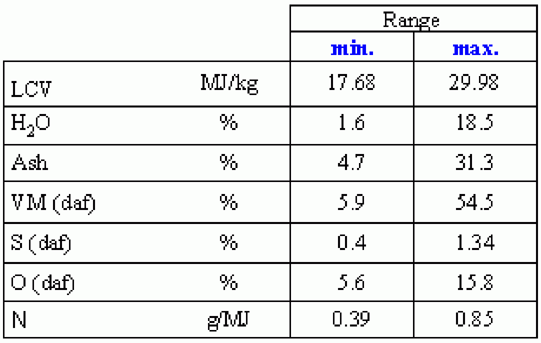


Figure 4.30: NO_X emissions of several retrofitted boilers
[67, EPPSA, 2001]

In Figure 4.30, the curve recorded for the DS burner at the plant (lower/green line) is shown in comparison with NO_X values of former whirl burners (WS burner – i.e. red/middle line) and the first generation of low NO_X burners (Vortex burner – i.e. blue/upper line). The chart clearly shows the potential of the DS burner for reducing NO_X.



		Range	
		min.	max.
LCV	MJ/kg	17.68	29.98
H_2O	%	1.6	18.5
Ash	%	4.7	31.3
VM (daf)	%	5.9	54.5
S (daf)	%	0.4	1.34
O (daf)	%	5.6	15.8
N	g/MJ	0.39	0.85

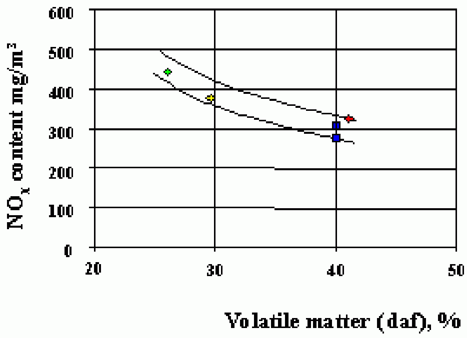


Figure 4.31: Performance of the swirl burner using different coals
[67, EPPSA, 2001]

Applicability: At a large number of plants in European and international markets the existing burners were converted into DS burners. In spite of certain implied design compromises, it was nevertheless, possible to achieve clear NO_X reductions, with an unchanged or sometimes even improved operating behaviour of the firing system. Figure 4.30 shows a comparison of the NO_X values before and after the burner conversion for some typical retrofitting projects (for example units A – H). The examples cover greatly different plants with capacities of up to 650 MW and with different coal qualities. Coal quality is an important factor for combustion-modification NO_X reductions (see e.g. Figure 4.31). Experience has been acquired with a very wide range of coals. Figure 4.31 gives the range of the coals which have so far been successfully fired in DS burners.

Cross-media effects: No potential effects due to implementing DS burners in firing systems.

Operational data: No potential increase in power consumption.

Economics: No additional operating costs.

Driving force for implementation: Requirement for low NO_X emissions.

Reference literature: [67, EPPSA, 2001].

EXAMPLE 4.2.1.5 HOT-TYPE FLUIDISED BED COMBUSTION (IGNIFLUID)

Description: Hot-type, or Ignifluid, fluidised bed technology is a combustion technique combining the advantages of conventional fluidised bed combustion (FBC) systems; such as fuel flexibility, superior carbon burnout efficiency and reduced emissions; with a high range of load variations and a selective output of agglomerated ashes.

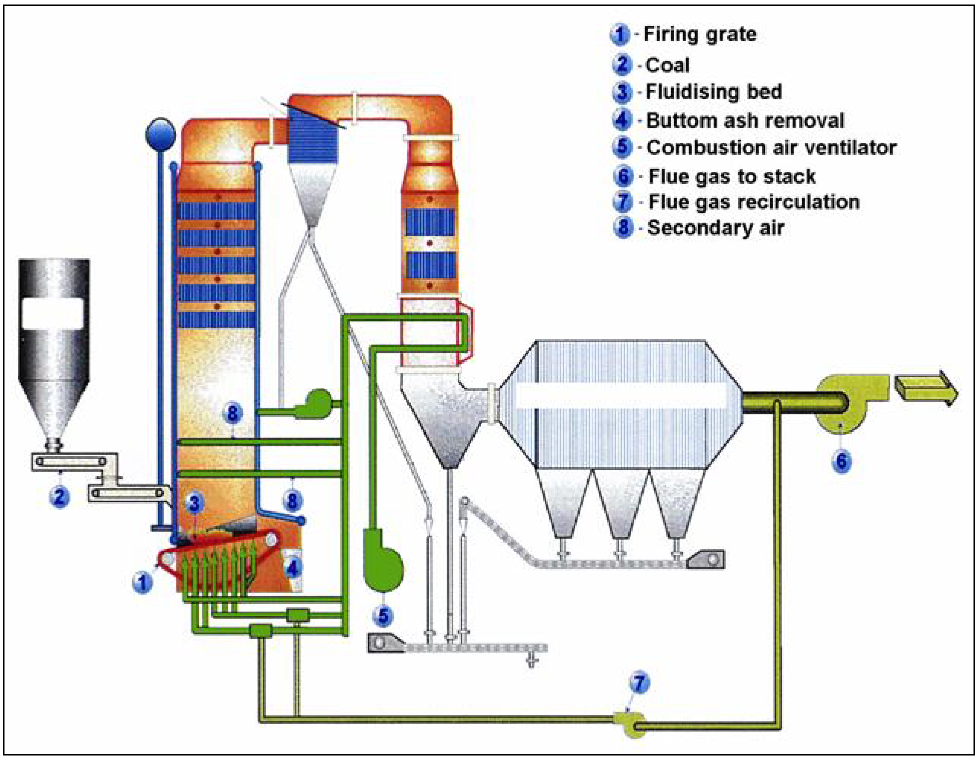


Figure 4.32: Hot-type ('Ignifluid') fluidised-bed technology
[139, MATE, 2001]

The main features include:

- the use of an inclined and travelling grate of fluidisation to ensure adequate distribution of the air and to remove agglomerated ashes from the bed (agglomerated ashes represent 85 % of the inerts)
- multistage combustion. The fluidisation airflow is much lower than the stoichiometric one, thus, fuel gasification occurs in the fluidised bed and secondary air is injected to achieve combustion
- a multistage dust collection system, with selective solid re-injection through the rear wall of the boiler in the fluidised bed
- flue-gas desulphurisation, by injecting limestone or hydrated lime at the same level as the secondary air
- a DENOX system (injection of urea or ammonia based reagents), if necessary.

The pressure parts of an Ignifluid boiler are quite conventional.

Achieved environmental benefits: The measured emission levels are as follows:

Pollutant	Measured emission level (mg/Nm^3)	Rate of reduction (%)	Technique used
NO_X	150/300		Injection of urea or ammonia based reagents
SO_2	400/600	50 – 85	Injection of limestone or hydrated lime at the same level as the secondary air
CO	100/150		
Dust	30/50		ESP
* with DESOX and DENOX			

Table 4.4: Overview of measured emissions (at 6 % O_2)

The power absorbed by the process is 7 – 8 kW_e/MW_{th} produced.

Applicability: This technology can be applied to new plants and fits a large range of fuels. As far as fuel versatility is concerned, experience to date shows that nearly all kinds of fuel can be burned regardless of the volatile index, ash content, moisture or swelling index. The sole problem seems to be obtaining the appropriate size distribution of the fuel for a good fluidisation and for a high combustion efficiency.

The hot-type fluidised bed technology is well adapted for a power range from 20 to 300 MW_{th}.

Cross-media effects:

- hot-type FBC is a dry process, and consequently produces no waste water
- the hot-type process mainly generates agglomerated ashes, which are extracted from the bed by the travelling grate. The ashes are suitable for the building industry
- fine ashes are also generated by the process. These are collected by the final dust collector and can be used as a raw material for the concrete industry, as a compound for special cement, as a material for road construction or as a fertiliser.

Operational data: Ignifluid technology was invented in 1955. Today more than 50 industrial plants in 11 countries have been built with it, representing an approximate global steaming capacity of about 3600 t/h. They account for more than 1400000 running hours.

Fuel:	Nearly all fluidising fuels Coals, oil-shales, washery rejects Various biomass
Monitoring:	Continuous measurements of: NO_X, SO_2, CO, dust, O_2, temperature and volume of flue-gas, atmospheric pressure, ambient air temperature and flue-gas volume
Ash re-use:	Bottom ashes extracted from the boiler are mainly agglomerated (85 % of the fuel inerts). This makes it easier to recycle (for example, in the building industry or in road construction).

Economics:

Costs for an Ignifluid boiler	60 MW_{th}	250 MW_{th}
Capital costs (EUR)	10000000	23000000
Operating costs/yr: Pollutant related only (EUR/yr)	250000	430000
Operating costs/yr: Extra power consumption (EUR/yr)	64000	110000
Operating costs/yr: Personnel and contingencies (EUR/yr)	330000	575000

Table 4.5: Costs for an Ignifluid boiler

The capital and personnel and contingencies costs indicated above are total costs for a facility and not marginal costs related only to pollutants abatement. The costs of FBC are not easily comparable with those of other pollution abatement technologies. From the available information it would seem that FBC offers a relatively low cost method for reducing both SO_2 and NO_X emissions.

Driving force for implementation:

- compatibility with solid waste re-use, due to ash agglomeration
- ability to change fuel while the boiler is still running
- quick cold start-up (≈ 4 hours)
- high rate of load change (≈ 20 – 25 % of MCR/min), partially due to the high carbon content in the bed (roughly half the input level)
- large turn-down range (≈ 1/10), due to a minimum of five windboxes with adjustable airflow under the grate
- in the combustion or co-combustion of biomass, there are advantages related to ‘greenhouse gas’ effects.

Reference literature: [139, MATE, 2001].

EXAMPLE 4.2.1.6 MEASURES FOR CFBC-POWER PLANTS TO ENHANCE SULPHUR CAPTURE, LIMESTONE CONSUMPTION AND CARBON BURN-OUT, ESPECIALLY FOR LOW QUALITY FUELS SUCH AS HIGH SULPHUR LIGNITE OR ANTHRACITE

Description: CFBC firing systems were first introduced in the 1970s for combustion purposes and are established today as reliable, environmentally friendly power plants for utilities, municipalities and industrial installations. In 2001, around 500 CFB plants were in operation worldwide. Applied capacities now exceed 250 MW_{th} and plants up to 600 MW_{th} plants are currently being designed.

The latest development of CFBs have been focusing on the low emission combustion of poor quality fuels including high sulphur and high ash fuels. Other objectives are to cut operational costs, mainly limestone costs and ash disposal costs. Furthermore, different steps to increase plant efficiency and to reduce CO_2 emissions (biomass firing, reduction in limestone usage) have been developed. Figure 4.33 depicts a CFB plant designed for high sulphur lignite.

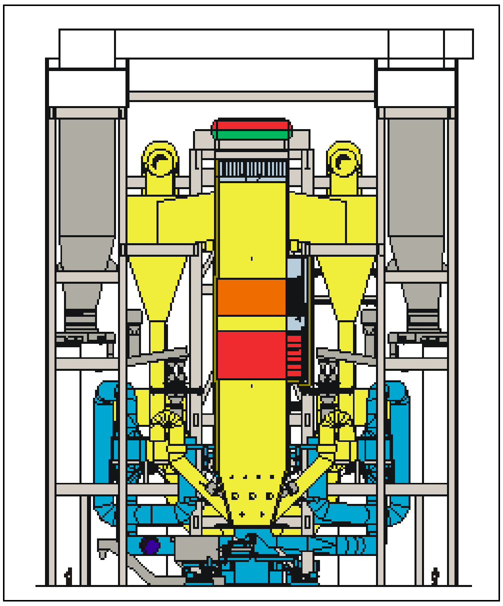


Figure 4.33: CFBC plant for high-sulphur lignite
[118, Alstom, 2001]

Achieved environmental benefits: The key benefits and developments concerning NO_X, SO_2, HCl, CO and combustion efficiency are described below.

NO_X: NO_X emissions for CFBC plants can be kept at low levels by applying primary measures, such as:

- using low furnace temperatures of approximately 850 °C, which suppresses the formation of thermal NO_X and keeps the conversion of fuel bound nitrogen to NO_X at low levels
- applying air staging, by injecting primary air (approx. 50 %) and multiple secondary air levels to create sufficient gas residence times at sub-stoichiometric conditions in the lower furnace
- optimising solids/gas mixing.

For high nitrogen or highly reactive fuels, additional measures, such as flue-gas recirculation or SNCR (ammonia injection at the furnace outlet or cyclone outlet), can be added at low expense.

SO_2: SO_2 emissions from the combustion of organic and pyritic sulphur in the coal, can be reduced by up to 95 % or more by '*in situ*' desulphurisation. The optimum temperature for the desulphurisation reaction is also in the range of 850 °C. The desulphurisation is achieved by the reaction of gaseous SO_2 and O_2 at the outer surface and within the internal porous structure of the CaO particles to form $CaSO_4$. The solids product is removed from the CFBC system together with the bed ash and filter ash.

For certain fuels, mainly lignites, where the ashes contain significant amounts of calcium, the majority of the SO_2 is captured by the so-called 'inherent' desulphurisation. In these cases, inherent capture in excess of 95 % can be achieved. For most other fuels, e.g. bituminous coals, the ashes do not contain substantial amounts of calcium. Therefore, crushed limestone at the appropriate particle size must be added to the furnace. To achieve desulphurisation rates of 95 % or higher, the molar Ca/S ratio is commonly in the range of 2 or higher. The limestone is mostly injected together with the fuel directly into the lower furnace or downstream of the loop seal. The Ca/S ratio depends on the appropriate particle size of the limestone, the limestone reactivity and its attrition characteristics.

The optimum particles size of the limestone must be in the range from 50 to 500 µm to give a sufficiently long residence time of the CaO particles in the furnace. Attrition and reactivity indexes are determined in laboratory tests according to buyers standards. They are determined by comparison with reference samples from existing databases. For high sulphur fuels, the cost for limestone and for ash disposal can become significant. Therefore, supporting technologies such as the duct sorbent injection (modified dry FGD, see Section 3.3.5.2) have been developed, e.g. to increase the reactivity of the limestone or ash.

Cl and F: Chorine and fluorine in the fuel are mostly combined with alkali components such as Na or K. At temperature levels of 850 °C, chlorine and fluorine form gaseous HCl and HF, which further react with CaO at lower temperature levels. Whereas for HF, more than 90 % is usually captured by the excess limestone in the filter ash, the retention rates for HCl can vary significantly. Depending on the moisture level in the flue-gas, the amount of excess limestone in the filter ash and the type of filter (ESP or baghouse), HCl retention rates between 20 % and 90 % have been detected. Thus, for high chlorine fuels, e.g. coal from the 'Saar' area in Germany, secondary measures such as $Ca(OH)_2$ injection can be installed.

CO: Due to the intense mixing in the furnace and in the cyclone, CO streaks are dissolved. For certain bituminous coals, mainly from the Southern Hemisphere, CO generation downstream of the cyclone was detected. Based on the slow reactivity of these coals CO is produced by unburned carbon, which settles on the first convective superheaters downstream of the cyclone. The CO production can be easily avoided by operating sootblowers in the superheater area.

Combustion efficiency: While for some first generation CFBC plants, carbon levels in the filter ash, especially for low ash and low reactive coals, exceed design expectations, significant improvements concerning combustion efficiencies have been achieved in recent years. As a first step improvement, the installation of filter ash re-injection systems for low ash coals resulted in an improvement in the combustion efficiency, especially for low ash coals. As a second step, the combustion efficiency was further significantly increased by enhancing the cyclone efficiency, leading to a total decrease by more than 50 %. This is due to a shift in the average particle size of circulating material from more than 180 µm to less than 100 µm.

Cyclone efficiency: The enhancement of the cyclone efficiency led to an improvement of approx. 50 % for combustion loss and more than 20 % for limestone usage. The homogeneous temperature profile further allowed NO_X emissions of less than 200 mg/Nm^3 to be achieved for the whole coal range without the need for controlling the furnace temperature by either external bed heat-exchangers or by using recirculation gas.

Applicability: CFBC firing systems of the type mentioned above have been implemented for power plants between 25 and 300 MW$_e$. The mentioned benefit of improving the cyclone efficiency is especially beneficial for high sulphur fuels (e.g. Indian and Turkish lignites), low reactive fuels (Chinese anthracite) and for fine grain fuels from coal washing plants. Currently more than six plants with the mentioned enhanced cyclone efficiency are in operation and 15 more plants are under construction.

Cross-media effects: The detected increase in pressure loss of the enhanced cyclone design, due to an increase in particle loading at the cyclone inlet, has been measured to be less than 2.5 mbar. Thus, no significant impact on power consumption has been detected.

Uses for CFBC ash are less developed than for FGD gypsum because they contain $CaSO_4$ and,therefore, cannot be re-used in concrete. Instead, the ash is used in road construction and in other civil engineering applications. However, at present only 40 – 50 % of CFBC ashes are currently used.

Operational data:

Fuel type	NO_X (mg/Nm^3 at 6 %O_2)	SO_2 (mg/Nm^3 at 6 % O_2)	Desulphurisation efficiency (%)
Anthracite and anthracite tailings	70	220	80
Pet-coke	100	50	99
Coal slurry	110	140	95
Bituminous coal	80	200	95
Eastern US bituminous coal	60	100	97
High moisture lignite	140	200	90
High sulphur lignite	160	200	98
Biomass	100		

Table 4.6: Typical NO_X and SO_2 emissions for CFBC plants

Economics: The improved cyclone efficiency has a good investment return. Retrofitting the eccentric vortex finder has also proven to be economical.

Driving force for implementation: Economical requirements in combination with more stringent requirements on SO_2 emissions.

Reference literature: [118, Alstom, 2001].

EXAMPLE 4.2.1.7 ELECTROSTATIC PRECIPITATORS (ESPS)

Description: Electrostatic precipitators (ESPs) are today commonly used devices for the collection and reduction of particles or aerosols in dusty atmospheres, such as in flue-gases from combustion processes. (A detailed description is given in Chapter 3). Typical outer dimensions of a large ESP are: height 30 m (active height less than 15 m), length 40 m and width 60 m. The lifetime of an ESP can be several decades, providing all recommended maintenance is properly carried out. Some parts, such as hammers and bearings (or nozzles for wet ESPs), need regular replacement after a couple of years of operation as part of routine maintenance.

Achieved environmental benefits: The ESP is able to achieve low emissions. The designed collection efficiency of the particulate can be higher than 99.9 %, and therefore emissions of only a few mg/Nm^3 can be achieved. In many cases, emissions in the range of 10 mg/Nm^3 and less have been measured. However, by burning solid fuel with high ash content when the ash presents high resistivity, higher levels may appear. ESPs are very efficient devices for collecting ultrafine particles (<0.5 µm), providing the particles have the ability to agglomerate. ESPs are normally of a heavy-duty design leading to high applicability, and they are also relatively insensitive to disturbances in the process. Thus, short temperature deviations will not destroy the ESP, in this event as soon as the process is back to normal conditions, the ESP returns to its earlier performance level.

Applicability: The ESP has been used in almost every power application for the collection of particulates from flue-gases. The most common use is for coal firing, but pet coke, oil and various residues of oil, peat, orimulsion and different kinds of biomass are also among the fuels. The dry ESP should operate above the dew point of the flue-gas in order to secure removal of the ash from the internals into the ash handling system. The flue-gas conditions vary quite significantly depending on the application. Ash composition, ash loading, particle size, resistivity of the ash, and temperature, humidity, SO_2 and SO_3 content of the gas are examples of parameters which need to be considered when designing an ESP.

Cross-media effects: The ESP can control small particles efficiently. For modern plants with low emissions, (e.g. around 10 – 15 mg/Nm^3), the main mass emission is well below 2.5 µm. There is a difference between the emission caused by rapping and that by general re-entrainment (or ash that has not been precipitated at all). Rapping losses occur in the form of agglomerates and have coarser particle sizes. In order to control, e.g. $PM_{2.5,}$ the ESP must be sized for an emission close to what is allowed for $PM_{2.5}$. It is not possible to vary any ratio between fractional efficiencies for coarse and fine particulate in a practical way, i.e. lowering the amount of particles <2.5 µm will also lower the amount of larger particles.

The ESP produces some ozone. Small amounts have been measured downstream of ESPs, but this disappears fast and is not considered to be a problem today.

Operational data: For low resistivity ashes, the current density used is normally limited to 0.5 mA/m^2 of collecting area, while for higher resistivity ashes the average current for optimum performance may be as low as 0.05 mA/m^2, and a corresponding power saving is achieved.

For difficult high resistivity fly ashes, there is an obvious advantage in reducing the inlet gas temperature for efficient collection of the particulate. Recently, there have been ESPs operating with gas temperatures of around 100 ºC. The coals used for these plants have a low S content (<1 %) and any generated SO_3 in the boiler is absorbed by the fly ash, so that no acid dew point can be detected. No problems with clogging or corrosion due to the low temperature have been reported.

The pressure drop across an ESP is normally <200 Pascal. Other energy consuming parts are mainly the hopper heaters (which may be in the order of 3 – 5 kW/hopper) and insulator heaters (about 1 kW/insulator). The power for the rapping devices is negligible compared to the other elements.

The ESP casing should be gas tight, i.e. there should not be any inleakage of air. If inleakage occurs, it can give rise to cold spots and corrosion and also to stratification of the flue-gas that can then change the currents and voltages leading to a deterioration of the efficiency. A gas-tight ESP and well insulated ESP should not have a temperature drop of more than 2 – 3 ºC.

Maintenance requirements are quite moderate. Statistics from Australia from the 1970s have shown that 90 % of the non-performing ESPs problems were actually due to malfunctioning ash discharge systems. With a good and reliable ash transportation system, it is common today for only one overhaul of the ESP to be needed per year. This usually takes place when there is maintenance work being carried out on the whole plant. An availability of >99 % can be achieved on new and well maintained plants. After some years moveable and wearing parts might have to be replaced and this is normally carried out during the yearly overhaul.

Economics: Investment costs for an ESP can be fairly high. They can range from EUR 16 - 53 per kW. The wide range depends on local fabrication costs, erection costs (which can vary significantly) and the size of the boiler and the ESP (which is a function of the efficiency and ash composition). For high resistivity ashes, there is often a substantial reduction in investment costs if flue-gas conditioning is implemented at the beginning of the build rather than as a later retrofit.

Operational and maintenance costs are normally low. The difference depends, to a great extent, on the local evaluation of the power consumption and maintenance costs.

Driving force for implementation: Low particulate matter emission levels.

Reference literature: [74, Alstom, 2001].

EXAMPLE 4.2.1.8 USE OF OPTIMISATION SOFTWARE

Description: The optimisation system consists of a row of optical sensors mounted on the upper furnace and a grid of *in situ* sensors inserted into the convective pass. The signal from each sensor is input into the computer system, which processes the signal and displays the appropriate parameters:

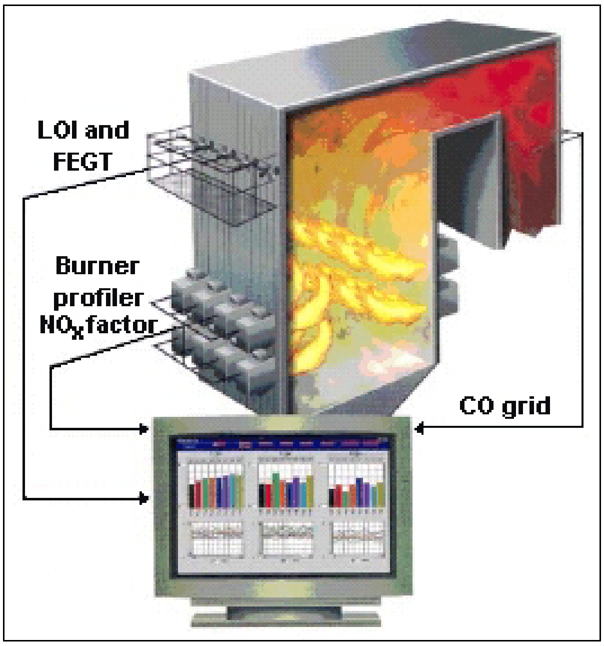


Figure 4.34: Computerised optimisation system
[175, Petek, 2002]

Achieved environmental benefits: Each plant has different optimisation objectives, so the software systems can be used as a tool to achieve many different results. The following is a list of potential benefits that have been achieved using optimisation systems to balance and improve combustion:

- heat rate improved (up to 2 %)
- Furnace exit gas temperature (FEGT) reduction
- NO_X reduction (up to 25 %)
- Loss-on-ignition (LOI) reduction (up to 50 %)
- CO reduction
- reduced O_2 levels
- improved unit availability – less forced outages
- cleaner furnace walls, less slag in convective pass
- reduced use of reheat and superheat sprays
- reduced localised tube overheat damage and tube failures
- reduced sootblowing
- safer operation due to the reduced risk of explosions caused by local fuel rich zones.

Applicability: New and existing plants.

Cross-media effects:.

Operational data: The benefit of optimising locally rather than globally is that burner and boiler adjustments can be targeted to correct specific problem areas. For example, if one burner was starved of air and produced high combustibles (LOI and CO), to rectify the problem an operator might increase the airflow to all the burners, because he was not aware which burner caused the problem. As a result, all the other burners receive more air than is necessary and consequently they generate more NO_X. A better way to address this problem is through adjustments targeted directly at the problem area. The purpose of optimisation systems is to pinpoint the source of the problem (i.e. a specific burner), to allow the operator to correct the problem locally. Thus optimisation techniques aim to optimise the entire boiler by identifying and maintaining the optimum mix of key combustion parameters at each local point across the boiler.

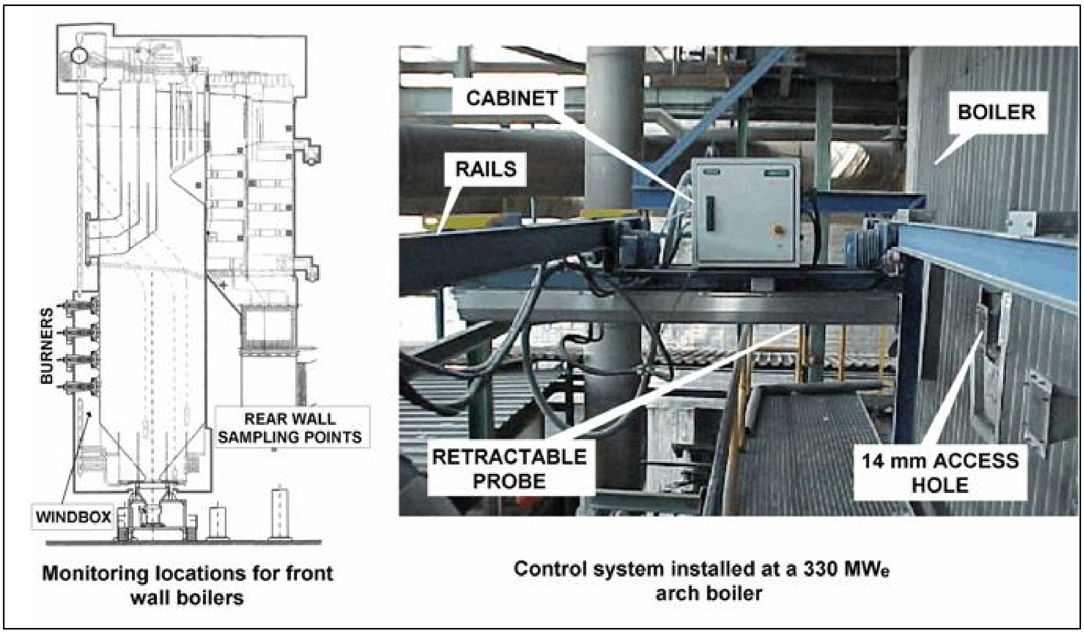
Economics: Not available.

Driving force for implementation: Better operation, less maintenance and lower emission levels.

Reference literature: [175, Petek, 2002].

EXAMPLE 4.2.1.9 ADVANCED CONTROL OF LOCAL COMBUSTION CONDITIONS TO REDUCE NO_X, AND BOILER PERFORMANCE IMPROVEMENTS IN COAL AND LIGNITE-FIRED BOILERS

Description: Boiler efficiency and NO_X generation in industrial boilers depend largely on the correct distribution of fuel and air in the furnace. This example control technology relies on the combination of local combustion balancing strategies and on the implementation of advanced combustion monitoring systems, allowing the application of stricter combustion control to solve common situations of imbalanced combustion scenarios. The system allows gas concentration measurements to be taken in any interior area of the furnace of industrial boilers, especially near the burners (Figure 4.35). This makes it possible to achieve not only important improvements in performance results (i.e. boiler efficiency, NO_X emissions, slagging, carbon-in-ash, consumption of auxiliaries), but also allows a safer and more flexible operation of the industrial boiler.



Monitoring locations for front wall boilers

Control system installed at a 330 MWe arch boiler

Figure 4.35: Characterisation of combustion conditions through advanced monitoring systems

The monitoring approach allows the measurement and evaluation of the local levels of gas concentrations (O_2, CO, CO_2, NO_X, SO_2), in those furnace regions which are normally at a high temperature and which, in the traditional design of boilers, have very limited access to them. The aim of these measurements is to enable the operator to characterise and control the combustion conditions at any particular point inside the boiler, in order to be able to optimise the heat rate, auxiliary consumption, pollutant emission and the slagging. This local combustion information makes it possible to consider the unit as a collection of small virtual units, each made up of a single burner. The targeted adjustment and regulation of each of these smaller units result in the overall optimisation of the boiler performance.

Applicability: This new concept for carrying out measurements inside the furnace of industrial boilers enables openings to be placed in any location required, without them being limited to only those inspection ports included in the original design of the boiler. In this way, it is possible to take measurements at the level of each burner in the boiler, without any significant structural modifications to the unit. Therefore, the presented control technology can be applied to both existing plants and new installations.

Table 4.7 shows the main characteristics of 16 existing coal-fired combustion plants from Spain and Portugal where this advanced control technology is currently being applied. These thermal units present different boiler designs (arch, arch-opposite, front, tangential) and types of fuel consumption (coals from lignites to anthracites and pet-coke).

Boiler design	Capacity (MW_e)	Number of units	Distribution of burners	Type of fuel
Arch	270	1	12 front wall + 12 rear wall	Anthracite
Arch	330	1	12 front wall + 12 rear wall	Anthracite
				Anthracite + pet-coke
Arch	350 – 360	2	12 front wall + 12 rear wall	Anthracite
Arch	360	1	12 front wall + 12 rear wall	Anthracite + bituminous
Arch	360	2	12 front wall + 12 rear wall	Anthracite
				Anthracite + pet-coke
Arch + opposite	315	1	Vertical: 8 front wall + 8 rear wall Horizontal: 8 front wall + 8 rear wall	Anthracite + bituminous
Front	160	1	4 vertical levels (4 burners per level)	Marginal + bituminous
Front	315	2	4 vertical levels (4 burners per level)	Bituminous
Front	360	2	6 vertical levels (4 burners per level)	Bituminous + lignite
Tangential	560	2	6 vertical levels (4 burners per level)	Bituminous

Table 4.7: Application of advanced control technology in coal-fired boilers

Achieved environmental benefits: The application of this technology has brought about NO_X reductions of around 30 – 60 % and substantial improvements in the overall plant performance (i.e. an increase of unit heat rate by up to 1 %). Table 4.8 shows the typical environmental benefits achieved by the application of this technology at thermal power plants with different boiler designs.

Boiler Type	Capacity (MW_e)	NO_X Reduction (%)	NO_X (mg/Nm^3, 6 % O_2)		Boiler efficiency increase (%)
			Baseline	Minimum level achieved	
Arch	270 – 360	20 – 60	1600 – 2000	800	1.0 – 2.0
Tangential	560	10 – 30	700 – 900	450	0.5 – 1.5
Front	160 – 360	>15	600 – 1100	-(1)	0.4 – 1.2
(1) Optimisation programme for NO_X reduction currently in progress					

Table 4.8: Typical reductions of NO_X emissions at PC power plants by the presented technology

Operational data: Figure 4.36 presents some specific results obtained through the application of this technology at a 330 MW_e PC power plant with an arch-fired boiler. This optimisation approach was based on:

- an appropriate adjustment of the overall excess oxygen, maintaining an adequate local stoichiometry for each burner
- adjustment of the flame type (based on an appropriate control of the air inputs and the operation of the mills)
- identification of the optimum number of active burners for each operating load
- the introduction in specific zones of limited quantities of fuel-oil for co-combustion.

All of these adjustments were made to aid the appropriate control of the individual operational conditions of each burner, based on the local combustion measurements.

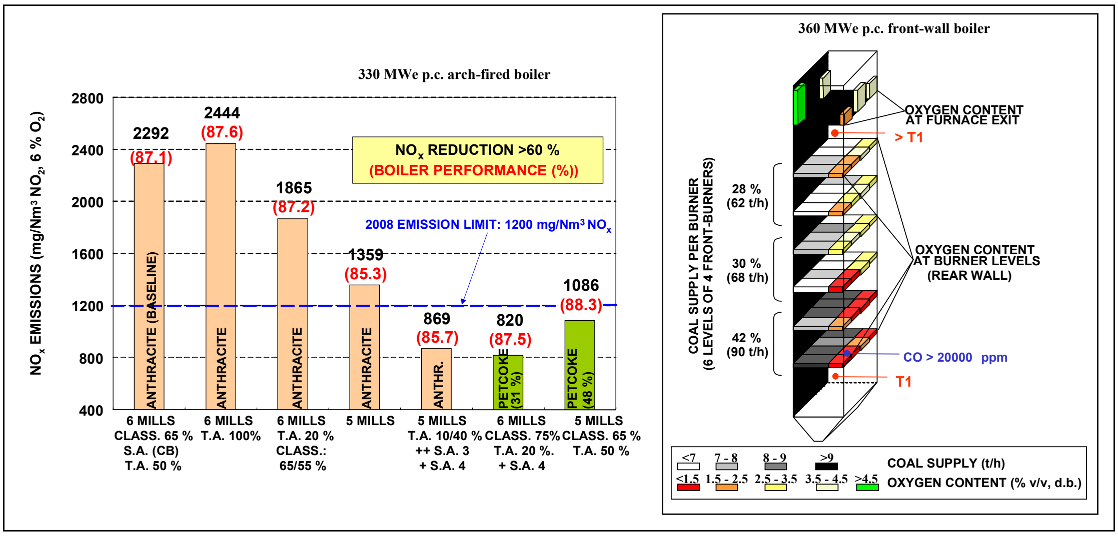


Figure 4.36: Results from PC arch-fired (anthracite) and front-wall-fired (bituminous + lignite) boilers

Figure 4.36 also presents the results obtained from a 360 MW_e front-wall fired power station, using this approach, respecting oxygen contents near the rear wall (corresponding to each flame tail). Significant differences between the oxygen levels corresponding to the tail of each flame (measured 1 m from the rear wall) were registered. These differences between the upper and lower levels of burners, also confirmed by CO measurements, were related to coal supply imbalances identified for this boiler. Measurements at the furnace exit also showed additional imbalances between the oxygen levels near the front and rear walls, that might be associated with differences in flame type. This was also confirmed through oxygen measurement at different distances (i.e. at 1 m, 2 m, and at 3 m) from the rear wall. Based on this type of information, boiler regulations were adjusted in order to control combustion conditions. These measures typically allow, for front-wall boilers, reductions in NO_X emissions of higher than 15 % and improvements in unit heat rate by up to 1.0 %.

Cross-media effects: In addition to the direct environmental benefits mentioned above, an advanced control of combustion conditions based on this advanced control technology offers the following additional advantages:

- an increase in flame stability
- a control of the creation of high reducing areas inside the furnace, thus reducing slagging and corrosion of the furnace tubes
- a reduction in the steam attemperation needs
- a reduction in CO emissions
- a reduction of the carbon-in-ash level
- an improvement in the ash quality
- a reduction in the auxiliary power consumption
- safer and more flexible operation of the boiler.

Economics: Implementation of the presented technology also generates important economic benefits derived from:

- an increase in the boiler efficiency
- an increase in the unit heat rate
- a reduction in the operational costs
- a reduction in maintenance costs
- a reduction of the unit unavailability and thus a reduction in losses of power production due to utility shutdowns
- an increase in the potential application of ashes to other industrial sectors (as cement industry).

The investment of this technological approach is currently in the range of EUR 300000 to 700000, depending on the particular characteristics of the unit under consideration (capacity, design, baseline operation, etc.).

Driving force for implementation: Besides a reduction in the fuel costs, the main reasons for application are a control of the NO_X formation and optimisation of the heat rate or slagging through the adjustment of oxygen and temperature distributions within the furnace.

Reference literature: [176, Cañadas and et al, 2001], [177, Rodríguez and et al, 2002], [178, ECSC, 2001].

4.2.2 Examples of applied techniques to improve the environmental performance of existing coal- and lignite-fired large combustion plants

EXAMPLE: 4.2.2.1 PULVERISED HARD COAL-FIRED DRY BOTTOM BOILER RETROFITTED WITH PRIMARY NO_X CONTROL AND SECONDARY DESULPHURISATION AND NO_X ABATEMENT

Description: The example plant was commissioned in 1983 in Germany and had a rated thermal input of 1820 MW, a gross electrical power of 750 MW_e and a mean electrical net power of 675 MW_e in 1999. It was equipped with a wet limestone scrubber (removal efficiency >85 %) and an SCR system between 1983 and 1989. The electrostatic precipitator reduces the dust emissions, with a separation efficiency of >99 %. For economical reasons, the boiler was retrofitted in 1997 to reduce the NO_X concentration in the raw gas and to increase the electrical efficiency of the plant.

Retrofitting of the primary NO_X control The described measures were motivated by the expected cost reduction due to decreased ammonia consumption in the SCR system, longer lifetime of the catalyst, the reduced need of power for the induced draught system and a higher boiler efficiency due to the lower excess air. Compliance with emission limit values for NO_X had already been achieved with the existing SCR system. The superposition of axial and a radial air staging allowed the area close to the furnace wall to obtain a high content of O_2 and a low content of CO. This offered an efficient protection against corrosion. Due to the use of low NO_X burners (excess air ratio $\lambda < 1$) and a burnout zone in the upper part of the boiler (excess air ratio $\lambda > 1$) the overall excess air ratio could be reduced from 1.3 to 1.25. The changes of operation data due to these measures are displayed in Table 4.9.

Parameter	Units	Operational data - before retrofitting	Achieved operational data - after retrofitting
NO_X after boiler	mg/Nm^3 (6 % O_2)	850	250 – 300
CO emission	mg/Nm^3 (6 % O_2)	<10	<10
Combustible matter in fly ash	%	approx. 1	2 – 3
Consumption of ammonia	kg/h	600	<275
Minimum catalyst activity	m/h	21	n.a.
Power demand of: • fresh air fan • induced draught system • desulphurisation fan	 kW kW kW	 5600 5420 3400	n.a.
Temperature of exhaust gas	°C	130	approx. 128
Boiler efficiency	%	92.53	>92.83
Reheater injection	%	1.7	c. 0.3

Table 4.9: Comparison of relevant operational data before and after retrofitting primary NO_X control measures

The saved power demand totalled 2.53 MW_e. That meant an increase of electrical net efficiency of 0.14 percentage points. A further reduction of the excess air ratio to 1.15 would have been possible by changing the design of the heating surface, and would have resulted in an additional increase of the electrical net efficiency of 0.2 percentage points. This was not implemented due to low cost efficiency reasons. The old coal mills were not changed. New ones could have reduced the content of combustible matter in the fly ash.

Achieved environmental benefits: The described retrofitting of the boiler reduced the consumption of auxiliary materials such as ammonia and the electrical power demand. This accounted for a saving of CO_2 per unit of energy produced.

Applicability: The retrofitting measures were adapted to the specific plant, but in general they can also be applied to other dry bottom boilers with high excess air ratios. However, retrofitting a boiler cannot be standardised and must, therefore, be planned and carried out on a case-by-case basis.

Cross-media effects: Flue-gas cleaning produces ash (electrostatic precipitator), waste water and gypsum (desulphurisation). The operation of the flue-gas cleaning systems reduces the electrical net efficiency of the plant.

Operational data: In 1999, the plant was in operation for 5855 hours and produced 3107.3 GWh of electricity with an electric efficiency of 37.1 %. The plant was designed to operate at a net electric efficiency of 38.3 %. The following emissions to the air were measured:

	Measured emission levels at 6 % O_2	Specific emissions (g/MWh$_e$)	Measurement
O_2 content (%)	7		Continuous
Operational state	Full load		
Flue-gas volume flowrate (m^3/h)	2500000		
Dust (mg/Nm^3)	<10$^{1)}$	37	Continuous
SO_2 (mg/Nm^3)	150$^{1)}$	556	Continuous
Sulphur emission rate (%)	10		Continuous
NO_X (mg/Nm^3)	190$^{1)}$	704	Continuous
CO (mg/Nm^3)	12$^{1)}$	44	Continuous
HCl (mg/Nm^3)	<30		Individual
HF (mg/Nm^3)	<3		Individual
Notes: 1 annual mean value at 6 % O_2, equivalent to daily mean at normal operation			

Table 4.10: Measure emissions to the air in 1999

Fugitive emissions arise from the storage and handling of coal. Annual emissions were estimated at 102 kg/yr. To reduce emissions, encapsulation of the coal discharge station was carried out and an underground coal conveying system was installed.

1081.5 kilotonnes of hard coal from two German mines and 3597 t of heavy fuel oil were fired. The characteristics of the coal used is shown in Table 4.11.

Lower heating value (MJ/t)	26500
Water content (%)	8
Sulphur content (%)	0.7 – 0.9
Ash content (waf) (%)	7.5 - 10
Volatiles (waf) (%)	32 - 38
Nitrogen (waf) (%)	0.9 – 1.6
Grain diameter (mm)	0 - 20
Grindability, Hardgrove (°H)	42 - 55
Cl (waf) (%)	<0.45

Table 4.11: Average characteristics of the fired hard coal

The waste water flowrate of the whole plant amounted to 280 m^3/h. Some 80 m^3/h originated from the condensate treatment and other sources of the steam generation. After neutralisation and sedimentation, this waste water was discharged to a river, with mean concentrations of impurities as shown in Table 4.12. Water from the cooling tower (160 m^3/h) was released to the river without any treatment. After neutralisation, precipitation, flocculation, sedimentation, biological treatment and filtration, waste water from the desulphurisation (40 m^3/h) was dumped to the river with mean concentrations of impurities as shown in Table 4.12.

	AOX	COD	P_{total}	N_{total}	Cr	Cd	Cu	Pb	Ni
Concentration (mg/l)	<0.05	28.4	0.35	15	<0.005	<0.0005	0.17	<0.01	<0.01
Specific load (g/MWh$_e$)		4.26	0.11	2.25			0.026		
Statistical mode		Median	Median	Median			Median		

Table 4.12: Concentration of impurities in the waste water from the condensate treatment and other sources of the steam generation process

	Filterable matter	Sulphate	Sulphite	Fluoride	Hg	Sulphide	Cd	Ni
Concentration (mg/l)	25	900	<1	7	<0.005	<0.02	0.01	0.05
Specific load (g/MWh$_e$)	1.9	68		0.5				
Statistical mode	Median	Median		Median			Median	Median

Table 4.13: Concentration of impurities in the waste waters from the desulphurisation process

The legal requirements for noise control depend on the nearest noise receptor, in this case a residential area about 300 m away from the plant. Appropriate noise requirements were met by using acoustic absorbers, encapsulation of single installations, acoustic screens around the cooling tower and overhead noise barriers.

Economics: The total investment for the plant amounted to EUR 791 million, including the flue-gas cleaning systems (1983 – 1989). The electrostatic precipitators accounted for EUR 39.5 million, the retrofitted desulphurisation EUR 111.2 million, and the retrofitted SCR EUR 38 million. The described retrofitting for primary NO_X reduction required an investment of EUR 6 million. The investment for fugitive emission control (encapsulation of the coal discharge station and an underground coal conveying system) amounted to EUR 12.5 million.

Driving force for implementation: The reason for the retrofitting of the boiler was the improved economic performance and the higher efficiency. The desulphurisation and the SCR system were realised in the 1980s due to lower emission limit values which came into force at that time.

Reference literature: [98, DFIU, 2001].

EXAMPLE 4.2.2.2 RETROFITTING A PULVERISED LIGNITE DRY BOTTOM BOILER WITH PRIMARY NO_X CONTROL, SECONDARY DESULPHURISATION AND IMPROVING EFFICIENCY

Description: An example plant operated in Germany consists of six identical units and has a net electricity output of 6 x 465 MW$_e$, a gross output of 6 x 500 MW$_e$ and up to 6 x 58 MW$_{th}$ energy off-take for district heating. The lignite is extracted from the nearby opencast mine. The crushed lignite is fed into the forced-circulation boiler with tangential-firing and wet coal mills, with a deflecting air separator. Each unit consists of two boilers and a steam extraction turbine. The flue-gas is cleaned and released to the air from the natural draught cooling tower. The boilers produce steam at 176 bar and 535 °C. With reheating, the steam parameters are 44.4 bar/540 °C. The retrofitting of the units was performed between 1991 and 1995. The measures undertaken aimed to lower the air emissions and to increase the efficiency.

Measures to improve the efficiency: The net electrical efficiency was raised from 32.5 to 35.7 %. This was partly achieved by exchanging the steam turbine's low pressure unit. The main boost to the efficiency came from the retrofitting of the boiler, which was primarily fitted to reduce NO_X emissions. With the help of air- and fuel-staging the flue-gas volume flowrate was reduced form 1.4 million m^3/h to 1.15 million m^3/h. Thus the temperature of the flue-gas decreased from 200 to 170 °C. A small part of the efficiency boost resulted from the refitting of the nine cooling towers. The individual measures and their effects on the efficiency are shown together in Figure 4.37. The improvement of the efficiency led to a total reduction of CO_2 (greenhouse gas) from 1991 – 1996 of 1296545 tonnes.

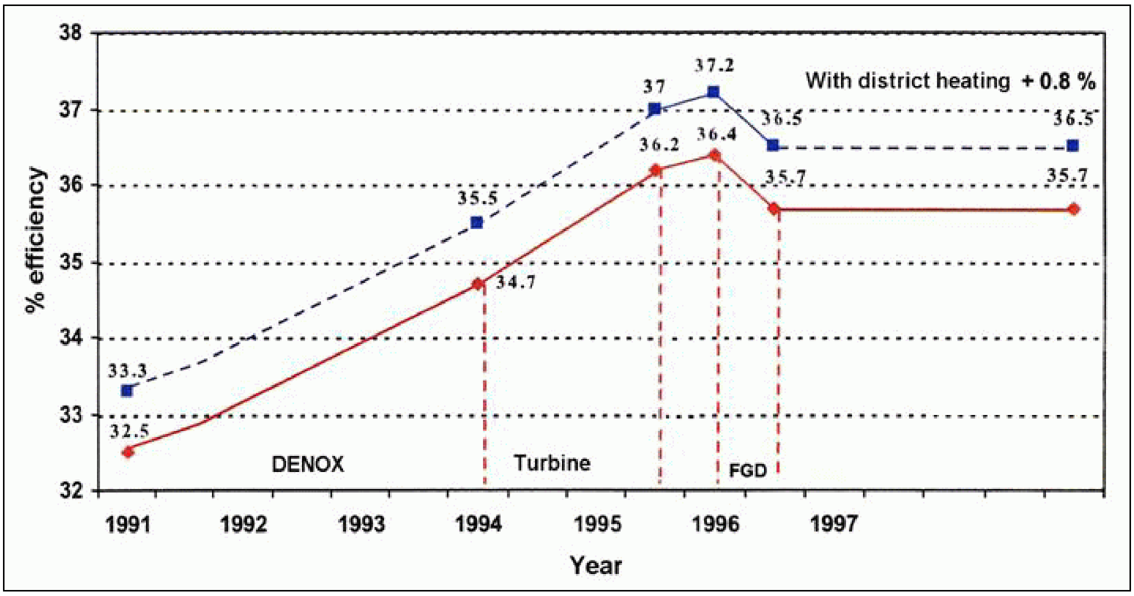


Figure 4.37: Efficiency improvement
[92, VEAG, 2000]

Primary measures for NO_X reduction: The NO_X emissions were halved to <200 mg/Nm^3 with the help of the following measures:

- at least 80 % of the combustion air was fed into the boiler in a controlled way by air-staging. To fulfil this requirement, the boiler had to be sealed to reduce the amount of uncontrolled combustion air by 65 %
- the air factor at the burners was lowered to 1 – 0.85
- an optimised fuel splitting with a scum separator was implemented
- cold flue-gas was recirculated
- staged combustion was applied
- complete CO conversion was ensured by two levels of burnout air injection.

Desulphurisation: Every boiler was retrofitted with a wet flue-gas desulphurisation unit. The main tanks were made of high grade steel. The concentration of SO_2 in the raw gas reached values of up to 7700 mg/Nm^3. There was no need to install a bypass for the FGD. The cleaned gas was conducted to the cooling towers via tubes made of glass reinforced plastic (GRP). Emissions via the cooling towers eliminated the need to reheat the cleaned gas.

Dust control: The existing electrostatic precipitators were retrofitted and reached separation efficiencies of above 99 %. Additional dedusting occurred in the wet FGD unit.

Achieved environmental benefits: The efficiency boost of 3.2 percentage points consequently reduced the fuel consumption and the CO_2 emissions by 10 %. The wet FGD reduced the concentrations of SO_2 in flue-gases from 4000 – 5000 mg/Nm^3 to <200 mg/Nm^3. The primary measures to reduce NO_X were of special importance as they not only halved the NO_X emissions but also increased the efficiency by 2.2 percentage points.

Applicability: The ESP and the wet FGD are standard emission control measures at lignite-fired power plants. Primary measures to reduce NO_X emissions can, in most cases be retrofitted, although they demand much more individual planning than end-of-pipe measures. The measures to increase efficiency, such as improved boiler efficiency, retrofitting of the turbines and more efficient cooling systems are, in principle, transferable to other plants.

Cross-media effects: Flue-gas cleaning produces fly ash (electrostatic precipitator), waste water (wet FGD) and gypsum (wet FGD). Operation of the flue-gas cleaning systems reduces the electrical net efficiency of the plant by 0.7 percentage points.

Operational data:

	Monitoring	**Annual mean values of the individual units at 6 % O_2**	**Annual mean values for the whole plant at 6 % O_2**	**Specific emissions (g/MWh$_{e,net}$)**
O_2 content (%)	Continuous		5.4	
Flue-gas volume flowrate (m^3/h)	Continuous		865000	
Dust (mg/Nm^3)	Continuous	<20 (upstream FGD) 3 (downstream FGD)	3	0.91
SO_2 (mg/Nm^3)	Continuous	140 – 200	170	51.51
Sulphur emission rate (%)	Continuous	2.7 – 5	3.8	-
NO_X (mg/Nm^3)	Continuous	164 – 188	176	53.31
CO (mg/Nm^3)	Continuous	164 – 200	182	55.15
HCl (mg/Nm^3)	Individual	<1^1	1$^{1)}$	0.30
HF (mg/Nm^3)	Individual	<1^1	1$^{1)}$	0.30
Notes: 1 Mean value of individual measurements				

Table 4.14: Measured emissions to the air in 1999

24693.4 kt of lignite (equivalent to 1.13 kg/kWh$_e$) and 7482 t of light fuel oil were fired. The characteristics of the fired lignite are shown in Table 4.15.

	Mean values for the reference year	**Variation limits for lignite from the nearby mine**
LHV (MJ/t)	8611	7600 – 9000
Water content (%)	55.3	48 – 56
Sulphur content (%)	0.93	0.5 – 1.4
Ash content (%)	9.3	5.5 – 15.2

Table 4.15: Characteristics of the fired lignite

The consumption of the most important auxiliary supplies is shown in Table 4.16.

Auxiliary material	**Limestone**	**NaOH**	**HCl**	**NH_4OH**	**H_2SO_4**
Application	Wet FGD	Water treatment			
Consumption (t/yr)	684000	357	487	12	1230
Specific consumption (g/MWh$_e$)	31400	16	22	0.6	56

Table 4.16: Consumption of important auxiliary supplies in 1999

The water demand for the whole plant at full load amounted to 11000 m^3/h. The cooling towers evaporated 5800 m^3/h, and 7580 m^3/h of water was discharge to the adjacent river from the cooling system. The total waste water flow amounted to 1087 m^3/h. A part of this flow (516 m^3/h) resulted from the cooling tower make-up water treatment, the full water softening, the steam generation and other minor sources. This waste water was either treated with precipitation, flocculation and sedimentation or was discharged to an external sewage treatment plant.

	AOX	COD	P_{total}	N_{total}	Zn	Cr	Cd	Cu	Pb	Ni
Range of measured concentration values (mg/l)	0.02 – 0.038	15 - 24	0.05 – 0.07	0.2 – 2.8	0.01 – 0.05	<0.1	<0.03	0.01 – 0.04	0.002 - 0.04	<0.01
Annual mean concentrations (mg/l)	0.03	19.2	0.06	1.7	0.04	<0.1	<0.03	0.03	0.02	<0.01
Specific load (g/MWh_e)	0.06	4.12	0.01	0.36	0.01			0.06	0.005	
Note: Waste water treated from tower make-up water treatment, the full water softening, steam generation and other minor sources. Data from 1999. Mean values 516 m^3/h										

Table 4.17: Concentrations of impurities in the waste water after the waste water treatment plant

	Bottom ash	Fly ash	FGD gypsum
Quantity (t/yr)	491000	1815000	1210200
Specific Quantity (kg/MWh_e)	0.022	0.083	0.055
Utilisation/Disposal	Cement industry; landscape architecture (reinforcement of embankments)	Reinforcement of embankments for gypsum depot and landscape architecture; material for cement and building industry	Gypsum industry; partly stored for long-term use in empty lignite mine

Table 4.18: Residues generated in 1999

Economics: The total investment for the retrofitting amounted to EUR 1759 million (1996). That related to a specific investment of EUR 643/kW_e. Table 4.19 shows the investment for the individual measures of the retrofitting.

Improvements	Costs (EUR million)
Wet FGD plants	1154
NO_X Reduction	176
Retrofitting of 24 ESPs	12.3
Sanitation of 9 cooling towers	115
Retrofitting of the turbines	85
Renewal of the control and instrumentation technology	267

Table 4.19: Investments for retrofitting

Driving force for implementation: The reasons for the retrofitting of the ESP and the realisation of the wet FGD and primary measures for NO_X reduction were the more stringent emission limit values which came into force in 1996. Without these measures the plant would have had to be shut down.

The retrofitting of the boiler was motivated by the obligation to reduce the NO_X emissions, but doing so could also significantly increase the efficiency and thus improve the economic performance of the plant. The optimisation of the efficiency was primarily realised for economic reasons.

Reference literature: [98, DFIU, 2001], [92, VEAG, 2000].

4.2.3 Examples of techniques applied to new coal- and lignite-fired large combustion plants

EXAMPLE 4.2.3.1 PULVERISED HARD COAL-FIRED DRY BOTTOM BOILER COMBINED CYCLE CO-GENERATION PLANT WITH FLUE-GAS CLEANING

Description: The coal-fired boiler is operated together with a gas turbine combined cycle where the waste heat boiler is part of the steam cycle from the coal-fired boiler This combined operation allows high power values and efficiencies at different loads as shown in Table 4.20.

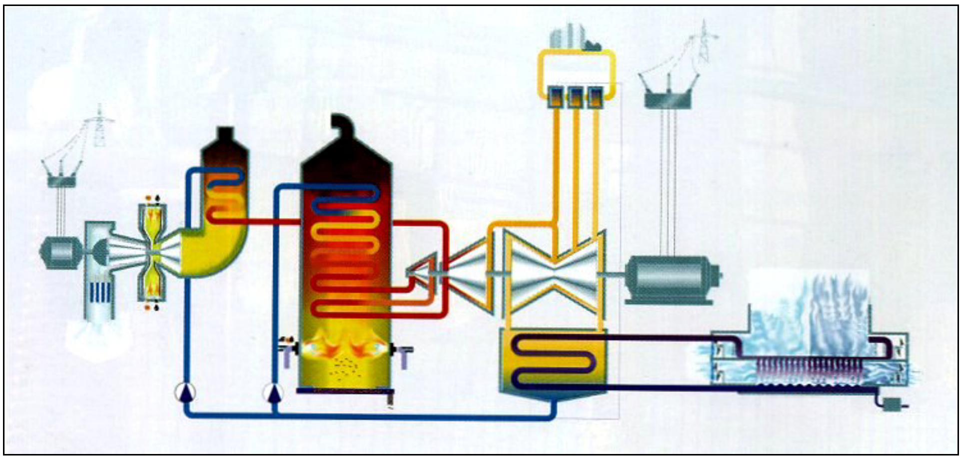


Figure 4.38: Coal-fired boiler operated together with a gas turbine combined cycle [140, NWS, 2000]

Operation mode	Electricity only		Co-generation of heat and power			
	P_e (MW)	$\eta_{el,net}$ (%)	P_e (MW)	$\eta_{e,net}$ (%)	P_{heat} (MW)	Overall efficiency factor (%)
Combined operation	397	44	355	38	280	70
Boiler only	302	41.2	246	34.7	280	72
Gas turbine only	65	36	63	35	87	83

Table 4.20: Performance data at different operational states [140, NWS, 2000]

Coal from the world market is ground in six coal mills before being burned in 12 staged combination burners. The single-draft boiler ('Benson' type) has three burner levels. After cleaning, the flue-gas is released to the air via a 250 m high stack made of reinforced concrete together with an acid-resistant lining inside. The turbine steam parameters amount to 284 bar/545 °C and 61 bar/569 °C after reheating. The 42 m high hybrid wet-dry cooling tower emits up to 420 MW of heat. The gas turbine has a rated thermal input of 184 MW and is equipped with 24 hybrid burners in an annular ring combustion chamber. The turbine gas conditions are 17 bar/1160 °C. The exhaust gas (560 °C) is used in the double-draft Benson-type boiler to produce steam (64 bar/540 °C). The cooled flue-gas is then emitted to the air without any further cleaning.

Measures for an optimised performance: An electrical net efficiency of 44 % and an overall efficiency factor of 70 % for combined operation are achieved by the following individual measures:

- utilising combined operation with gas turbine: at full load, the net efficiency increases by 2.8 percentage points compared to individual operation of the boiler. Compared to the alternative exhaust gas-side coupling of a coal-fired boiler with a gas turbine (i.e. the hot flue-gas of the gas turbine is used as combustion air in the coal-fired boiler) the presented process can also reach high efficiencies at part load conditions. The maximum net efficiency is with a 50 % load, but a 40 % efficiency can be achieved even with only a 25 % load.
- operating at high parameters for the turbine steam conditions
- optimising steam turbine technique
- reducing the auxiliary power requirements (e.g. by operating efficient desulphurisation and by having an induced-draught system)
- applying regenerative feed-water heating (274 °C)
- having a high boiler efficiency (94.4 %)
- optimising the condenser
- running an highly efficient gas turbine (36 % net efficiency).

The hybrid wet-dry cooling tower was installed to prevent plumes appearing over the nearby residential area. The required venting system has an electricity demand of 3 MW_e.

Measures to reduce NO_X emissions: With low NO_X burners, a NO_X concentration of 350 mg/Nm^3 in the raw gas of the coal-fired boiler can be reached. The subsequent SCR system is located in a high dust position and reduces the NO_X content to the legally binding level of 130 mg/Nm^3 (at 6 % O_2). It is made up of two units with a combined volume of 250 m^3. The ammonia consumption can be up to 100 kg/h.

Desulphurisation: The wet limestone scrubber has a removal efficiency of 96 – 98.5 % and is made of high alloy stainless steel plated onto ST 37 as the base material. The pipes and tubes are made of epoxy-glass resin. The power consumption of the system rises to 3.4 MW_e. The vacuum filter dewaters the gypsum to a water content of 10 %.

Dedusting: Four electrostatic precipitator lines with a total area of 61400 m^2 reduce the dust load by 99.92 %.

Achieved environmental benefits: The implementation of the combined technique allows high efficiencies to be obtained at different loads and operational modes. Primary and secondary measures lead to low emissions to the air. The re-use of waste water reduces the water consumption (waste water from the ash water treatment and from the desulphurisation water treatment are used for the cooling process). The hybrid wet-dry cooling tower is virtually cloud free and evaporates about 20 % less water than a natural draught cooling tower.

Applicability: For the type of plant described, the requirements for a potential site are: a demand for district heating, sufficient water resources and the availability of transport facilities for the coal. The decision for retrofitting an existing coal-fired boiler with a gas turbine depends on local conditions.

Cross-media effects: The catalyst in the SCR plant needs to be replaced periodically. Operation of the desulphurisation system reduces the electrical net efficiency by 0.38 percentage points, and the cooling tower reduces it by 0.33 percentage points compared to a natural draught cooling tower.

Operational data: In 1999, 1100 GWh of net electricity and 286 GWh of heat for district heating were generated. The number of equivalent full load hours amounted to 3860. Table 4.21 shows the emissions to the air from the coal-fired boiler and from the gas turbine in 1999.

	Coal-fired boiler		Gas turbine
	Measured emission level	**Specific emissions (g/MWh$_e$)**	**Measured emission level**
O_2 content (%)	5.9		15
Operational state	Rated thermal input 700 MW$_{th}$ (compound operation)		Rated thermal input 180 MW$_{th}$ (single and combined operation)
Flue-gas volume flowrate (m^3/h)	900000[1]		550000
Dust (mg/Nm^3)	5[1]	13.47	
SO_2 (mg/Nm^3)	20[1]	56.89	
NO_X (mg/Nm^3)	90[1]	254.49	70[3]
CO (mg/Nm^3)	16[1]	44.91	20[3]
HCl (mg/Nm^3)	2[2]	5.99	
HF (mg/Nm^3)	0.2[2]	0.60	

Notes:
1. continuous measurements, annual mean value at 6 % O_2
2. mean value of individual measurements
3. continuous measurements, daily mean value at 15 % O_2

Table 4.21: Measured emission levels in 1999

Some 360000 tonnes of hard coal from different parts of the world were fired in 1999. Additionally 1 million Nm^3 of natural gas and 1800 tonnes of light fuel oil were fired. The consumption of the most important auxiliary supplies are shown in Table 4.22.

Auxiliary material	Application	Consumption (t/yr)	Specific consumption (g/MWh$_e$)
Lime	Desulphurisation	470	430
Ground limestone		9000	8200
NaOH	Waste water treatment	120	110
HCl		230	210
H_2SO_4		50	46
FeCl		520	476
NH_3	SCR	890	815

Table 4.22: Consumption of important auxiliary supplies in 1999

The water consumption of the cooling tower was 540 m^3/h. Of this amount, 37 % was released to a nearby river, and the rest was evaporated. This effluent contained impurities such as COD (chemical oxygen demand) (20 mg/l), phosphorus (0.2 mg/l) and nitrogen (23 mg/l). The numbers in brackets are mean values for 1999. The waste water from the desulphurisation plant was treated in a separate installation with flocculation agents and subsequent sedimentation. 50 % of this water was then used as cooling water and the remaining 50 % discharged to the river. The concentration of impurities in this waste water is shown in Table 4.23.

	Mean value from 2 to 3 measurements (mg/l)	Specific load (g/MWh$_e$)
Chlorine	40000	1.20E+03
COD	<150	4.49E+00
Zinc	<1	2.99E-02
Chromium	<0.5	1.50E-02
Cadmium	<0.05	1.50E-03
Copper	<0.5	1.50E-02
Lead	<0.1	2.99E-03
Nickel	<0.5	1.50E-02
Filterable matter	17	5.09E-01
Sulphate	1542	7.61E+01
Sulphite	2	5.99E-02
Fluoride	8	2.40E-01
Mercury	0.007	2.10E-04
Sulphide	0.07	2.10E-03
Note: measurements in 1998/1999		

Table 4.23: Concentrations of pollutants in the waste water of the desulphurisation plant after treatment

	Ash (standardised quality)	Boiler sand	Lime sludge from cooling tower make-up water treatment	FGD gypsum, fine grained
Quantity (t/yr)	21000	3100	2500	14000
Specific Quantity (kg/MWh$_e$)	19.0	2.8	2.3	12.7
Utilisation/Disposal	Cement and concrete industry	Building material industry	Cement industry, fertiliser	Gypsum and cement industry

Table 4.24: Residues generated in 1999

The legal requirements for noise control depend on the nearest noise receptor, in this case a residential area about 400 m away from the plant. Appropriate noise requirements were met by using exhaust silencers, acoustic screens around the cooling tower and by panelling of the facade.

Economics: The total investment amounted to EUR 615 million at the time of commissioning. That related to a specific investment of EUR 1549/kW$_e$.

Driving force for implementation: The original reason for building the plant was the need to replace three old coal-fired boilers. These three boilers, from the 1950s and 1960s, offered a high flexibility in operation. The main rationale behind the compound technique was the possibility of keeping this high level of flexibility. High efficiencies for part load operation and short start-up and close-down times were the key advantages. A hybrid wet-dry cooling tower was already used in an existing plant at the same site and had proven to fulfil the requirements. Thus it was also used in the new plant to prevent visible plumes. The relative low emission limit values for emissions to the air were imposed because of the natural surroundings of the site, i.e. it was situated in a valley.

Reference literature: [98, DFIU, 2001], [140, NWS, 2000], [179, Lehmann, et al., 2000].

EXAMPLE 4.2.3.2 PULVERISED COAL-FIRED DRY BOTTOM BOILER WITH WET FGD AND SCR

Description: The example power plant was commissioned in 1994 and operated in Germany. It has a rated thermal power input of 1370 MW. The maximum power output is 553 MW_e gross electricity, 508 MW_e net electricity and 300 MW of heat. The electrical net design efficiency is 42.5 %. Coal from the world market is ground in four coal mills before being burned in 16 staged turbulent burners. The burners are located on four levels. After cleaning, the flue-gas is released to the air via a 141.5 m height cooling tower. The turbine steam parameters are 262 bar/545 °C and 53 bar/562 °C after reheating.

Measures for optimised efficiency:

- high steam parameters
- optimised turbines
- the main installations are built on one line.

Primary and secondary measures for NO_X reduction:

- low NO_X burners allow the achievement of NO_X concentrations in the raw gas of <500 mg/Nm^3
- SCR installation with three catalyst layers in a 'high-dust' position.

Desulphurisation:

- wet FGD using chalk as absorbent; without reheating; reduction efficiency >95 %.

Dust control:

- ESP with reduction efficiency of >99 %.

Achieved environmental benefits: The high electrical net efficiency leads to an economic use of resources (coal) and to low specific CO_2 emissions. Primary and secondary measures lead to low emissions to the air.

Applicability: A potential site for installing a plant of the described type requires a demand for district heat, and the availability of sufficient water resources and suitable transport facilities for the coal.

Cross-media effects: The residues accruing from the flue-gas cleaning are:

- fly ash (electrostatic precipitator)
- waste water and gypsum from the desulphurisation plant
- the catalyst in the SCR plant needs to be replaced periodically
- operation of the desulphurisation unit reduces the electrical net efficiency.

Operational data: In 1999, the plant was in operation for 5782 hours and produced 2481.3 GWh_e of net electricity and 168.8 GWh of district heat. The plant reached a mean electrical net efficiency of 40.4 % and a mean overall efficiency of 44.26 %. Table 4.25 shows the emissions to the air of the coal-fired boiler and the gas turbine in 1999.

	Measured emission level (half-hour mean value at 6 % O_2)	Specific emissions (g/MWh_e)	Measurement
O_2 content (%)	4		
Operation mode	Full load		
Flue-gas volume flowrate (m^3/h)	1580000		
Dust (mg/Nm^3)	3	9.11	Continuous
SO_2 (mg/Nm^3)	52	158.38	Continuous
NO_X (mg/Nm^3)	167	483	Continuous
CO (mg/Nm^3)	23	66.49	Continuous
HCl (mg/Nm^3)	<1.73		Individual
HF (mg/Nm^3)	<0.2		Individual

Table 4.25: Measured emission levels in 1999

Some 782 kilotonnes of hard coal from the world market were fired in 1999. Additionally 4170 tonnes of light fuel oil were fired. The consumption of the most important auxiliary supplies is shown in Table 4.26.

Auxiliary material	Application	Consumption (t/yr)	Specific consumption (g/MWh_e)
Chalk White fine lime	FGD	16139 588	6500 237
H_2SO_4	Water treatment	603	244
$FeCl_3$		396	159
NH_3	SCR	605	244

Table 4.26: Consumption of important auxiliary supplies in 1999

The cooling system is fed with water from the Baltic sea, without any demineralisation carried out. To prevent corrosion, the tubes of the cooling system are completely made of titanium. The thickened cooling water is dumped back to the sea, at a flowrate of 950 m^3/h at full load. The concentrations of impurities in this effluent are shown in the table below.

	Mean concentration (mg/l)	Mean specific load (g/MWh_e)
Cl	0.3	0.56
AOX	0.117	0.22
COD	35	65.5
P_{total}	0.191	0.36
N_{total}	0.47	0.88
Note: measurements in 1999		

Table 4.27: Concentrations of impurities in the effluent of the cooling system

The water demand of the wet FGD is met by a mix of seawater and source water. Treatment of the effluents of the FGD produces waste water (70 m^3/h) which is also discharged to the sea. The concentrations of impurities in the waste water of the desulphurisation plant after treatment are shown below.

	Mean values of concentration (mg/l)	Mean specific loads (g/MWh$_e$)
AOX	0.0383	0.002
COD	71	3.57
Zinc	<1	0.05
N$_{total}$	<10	0.5
Cr	<0.01	
Cd	<0.01	
Cu	<0.01	
Pb	<0.1	0.005
Ni	<0.02	
Filterable matter	<30	1.5
Sulphate	<2000	100.7
Sulphite	<20	1.00
Fluoride	<30	1.5
Mercury	<0.001	
Sulphide	<0.2	0.1
Note: measurements in 1999		

Table 4.28: Concentrations of impurities in the waste water of the desulphurisation plant after treatment

	Quantity (t/yr)	Specific Quantity (kg/MWh$_e$)	Re-use and discharge
Bottom ash	14150	6	Building material industry
Fly ash	81350	30	Building material industry
FGD gypsum	26300	10	Building material industry
Gypsum	2020	0.8	Waste site cover
Sludge from the cooling tower make-up water treatment	733	0.3	Waste site cover

Table 4.29: Residues generated in 1999

The legal requirements for noise control depend on the nearest noise receptor, in this case a residential area about 820 m away from the plant. Appropriate noise requirements were met by using exhaust silencers, acoustic screens, encapsulations and by avoiding periodically changing forces and pressures.

Economics: The total investment amounted to EUR 615 million at the time of commissioning. That related to a specific investment of EUR 1.118 per kW$_e$.

Driving force for implementation: The ESP, the wet FGD, primary NO_X control and the SCR were installed to comply with the emission limit values. Optimisation of the efficiency was primarily realised for economical reasons.

Reference literature: [98, DFIU, 2001].

EXAMPLE 4.2.3.2 CFB -BOILER IN UTILITIES AND INDUSTRIAL POWER GENERATION

Description: Increasingly stringent environment protection requirements tend to force boiler manufacturers and operators (both in the utilities and industrial sectors) to implement environment friendly solutions for solid fuel combustion processes. From this point of view, the circulating fluidised bed boiler is a remarkable power generation and pollution control concept. The main reason for the success of circulating fluidised bed furnaces lies in their ability to meet particularly stringent environment protection requirements for SO_2 and NO_X emissions, without the need for additional abatement equipment. Fluidised furnaces can be fired with a considerably wide range of fuels with low calorific values and high ash contents.

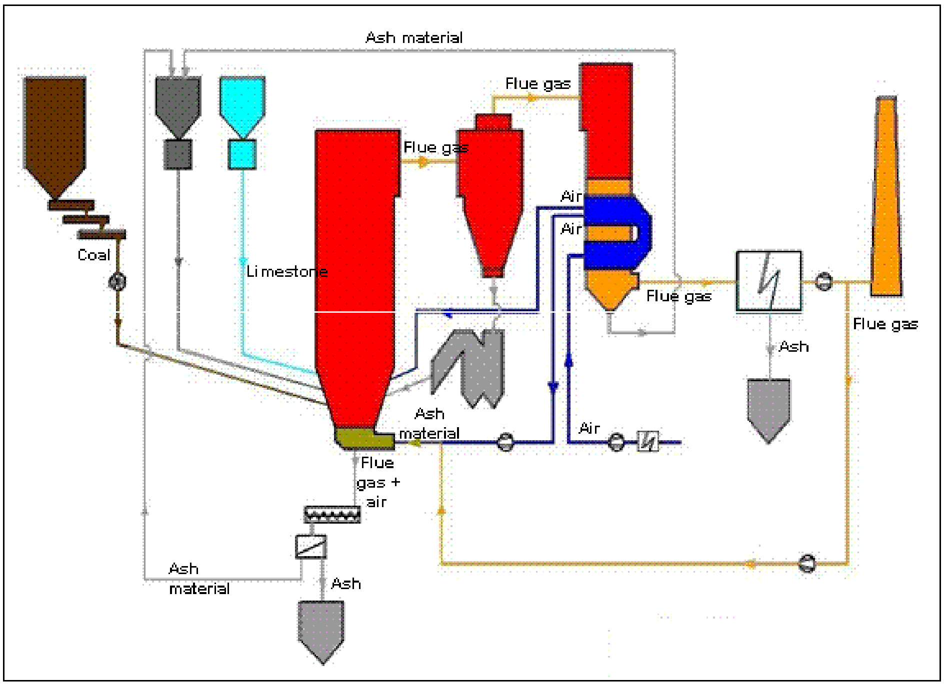


Figure 4.39: Industrial CFBC boiler

Achieved environmental benefits: SO_2 generated during combustion in fluidised furnaces can be efficiently captured with the addition of limestone sorbent. The quantity of limestone added is directly related to its quality. The ideal limestone additive should be amorphous, reactive and should have a $CaCO_3$ content exceeding 90 %. Sulphur-laden ash forms a marketable, dry waste product.

The low temperature combustion process (almost half the temperature of a conventional boiler) and a gradual feeding of the air result in a considerable decrease in the amount of NO_X formed from nitrogen in both the air and fuel.

Applicability: Circulating fluidised bed furnaces are particularly suitable for large and medium sized power generation boilers.

Cross-media effects: Erosion and corrosion are the most frequent problems related to fluidised bed combustion. The main reasons for these problems are the large mass of continuously circulating inert material and the reducing atmosphere within the furnace chamber hopper.

Operational data: SO_2 released during the combustion process is captured by the addition of limestone. The desulphurisation efficiency depends on factors such as the furnace chamber temperature, the sulphur content in the fuel, the limestone quality and on the grain size distribution.

The low combustion process temperature (850 - 870 °C) is below the temperature at which nitrogen pollutants are formed from combustion, hence thermal NO_X emissions from the nitrogen in the air are limited.

The gradual distribution of air within the furnace chamber hopper reduces the quantity of NO_X formed from nitrogen in the fuel.
When compared to lignite-fired boilers, hard coal-fired boilers tend to have higher CO emission values. The combustion of hard coal may increase the CO contents in the system if there is a substantial reduction in the sootblowing frequency for convective surfaces located downstream of the cyclone.

Table 4.30 below shows a comparison between the achieved emissions and the manufacturers' 'guaranteed' pollutant emission values for three hard coal-fired fluidised bed boilers operated in Poland (Plants A to B). Measurement results are referenced to 6 % O_2 contents in dry flue-gas.

Pollutant	**Plant A** (mg/Nm^3)		**Plant B** (mg/Nm^3)		**Plant C** (mg/Nm^3)	
	Measured	Guarantee	Measured	Guarantee	Measured	Guarantee
SO_2	121 – 141	300	80 – 168	200	290 – 320	400
NO_X	176 – 181	250	162 – 171	200	85 – 154	300
CO	81.1 – 84	250	84 – 96	250	105 – 224	250
Ash	28	50	26	50	15 – 23	50

Table 4.30: Comparison of achieved and guaranteed pollutants emission values for three hard coal-fired fluidised bed boilers operated in Poland

Economics: When compared with a pulverised fuel boiler of the same capacity (equipped with low emission burners and an external flue-gas desulphurisation plant) and to achieve the same environmental benefits, the investment costs for a CFBC boiler are lower. CFBC boilers also require less space for installation, which makes them especially suitable for retrofitting in existing plants.

CFBC boilers offer a more efficient, lower cost alternative to traditional emissions control methods. These traditional controls are generally built as facility additions to power plants, thus adding to the expense and complexity of the power plant and reducing its efficiency. In contrast, CFBC technology focuses on a total system improvement, that yields far lower emissions but, at the same time, giving far higher efficiency.

Driving force for implementation: Until recently, coal burning processes evolved principally to boost efficiency and to increase capacity. Nowadays, as environmental performance has become a critical requirement for power plant design, CFBC boilers are regarded as more efficient and less costly than conventional coal combustion technology.

CFBC boilers can meet both SO_2 and NO_X emission standards without any additional pollution control equipment. This combined with low investment costs, the relatively small area required for installation and the possibilities for firing with substandard, cheap, solid fuel are some of the many advantages that guarantee the future development of this combustion technology.

Reference literature: [195, Poland, 2001].

4.3 Current consumption and emission levels

This section provides information on currently observed (measured) emission levels to air, water and soil from LCPs. Information is given about the fuels used in this sector, their chemical and physical properties and the ranges of impurities that can generally be expected. As far as available, the data includes information about plant efficiencies and about any residues and by-products that may arise the different operations of an LCP, and also reflects any options for recycling and re-use of output streams within the whole process.

The extent of multimedia complexity will be indicated where interdependency exists between various inputs and outputs, for example where different parameters are dealt with together or where some trade-off has been made such that certain levels cannot be achieved at the same time.

Performance data will be qualified as far as possible by including details of operating conditions (e.g. percentage of full capacity), sampling and analytical methods, and on the statistical presentation of figures (e.g. averages, maxima, ranges). Actual performance data may be compared to relevant standards set in national or international legislation.

Current emission data in this document are normally reported as hourly or daily averages or as mass emissions per unit of energy generated. Dilution of the gases or waste water is not considered to be acceptable. The emissions to water that have been reported are normally based on a qualified random sample or a 24-hour composite sample. The standard conditions of 273 K, 101.3 kPa, stated measured oxygen content and dry gases are used.

4.3.1 Coal and lignite used in LCPs

Hard coal and lignite are currently the dominant solid LCP fuels in the EU. Coal deposits were formed as the result of complex anaerobic biochemical reactions under the effects of temperature, pressure and time, and which have taken place in stratified underground plant debris, thus enriching the carbon and hydrocarbon content of the original organic material. The chemical properties of coal depend upon the properties of the different chemical components present in the parent plant debris, the nature and extent of the changes and the nature and quantity of the inorganic matter present.

The first, immature product of the ‘coalification’ process is peat, -while the last degree of ‘coalification’ is anthracite. The degree of change of chemical composition of coal within the series of fossil fuels from peat to anthracite is known as the rank of the coal and corresponds to an increase in equivalent energy of coal (calorific value). The basis for the classification of coals by rank is the properties of coal as revealed by their chemical analysis and certain other factors, such as the agglomerating character.

- **the proximate analysis** - gives information on the behaviour of coal when it is heated (e.g. moisture, volatile matter, fixed carbon)
- **the ultimate analysis -** supplies information to assist in the selection of coal for steam generation (e.g. total carbon, hydrogen, nitrogen, oxygen, calorific value, ash-fusion temperature, grindability and sulphur content).

Three major classification systems have been developed based upon the proximate analysis of coals. These are:

- ASTM classification developed in the US
- FRB/NCB classification developed in the UK
- the ‘International Codification System’ for medium and high rank coals and the ‘International Codification System’ for low rank coal utilisation, developed by the UN/ECE.

According to the ASTM classification, there are four classes, based on fixed carbon and volatile matter (on a dry, mineral matter-free basis) and calorific value (on a moist, mineral matter-free basis):

- anthracite
- bituminous
- sub-bituminous
- lignite.

According to the FRB/NCB classification system, based upon volatile matter (on daf) and burning properties (Gray-King Assay) there are four groups:

- anthracites
- low volatile steam coals
- medium volatile coals
- high volatile coals (consisting of six sub-classes).

According to the UN/ECE International classification system, coals are defined as **higher rank** and **lower rank coals**, based upon their gross calorific value (on a moist, ash-free basis) and vitrinite mean random reflectance in oil. These categories are divided further into sub-categories. The higher ranking coals are divided into **medium and high rank coals**, while the lower ranking coals are divided into **lignite** and **sub-bituminous coals**.

It is very important to know as much as possible about the properties of a certain solid fuel, in order to be able to appropriately design the LCP installations and equipment to achieve best performance. It is equally important to burn the correct fuel for which the LCP was designed, or at least, a fuel with similar properties. This ensures high efficiency in the long term, as well as trouble-free operation and an optimum environmental performance.

Property	**Units** (waf = water- and ash-free)	**Lignite**	**Coal**		
			Bituminous	**Low volatile bituminous and semi-anthracite**	**Anthracite**
Moisture	(% as received)	30 – 70	2 – 20	2 – 20	2 – 20
Ash	(% as received)	5 – 40	1 – 30	1 – 30	1 – 30
Volatile matter	(daf %)	40 – 66	>22	8 – 22	<8
Fixed carbon	(daf %)	35 – 60	55 – 85	85 – 92	>92
Total carbon	(daf %)	60 – 80	80 – 95	90 – 95	92 – 95
Hydrogen	(daf %)	4.5 – 6.5	4.5 – 6.5	3.5 – 4.5	3 – 8
Oxygen	(daf %)	12 – 30	1.5 – 14	1.2 – 6	1.2 – 5
Sulphur	(daf %)	0.5 – 4.7	0.3 – 4.5	0.5 – 1	0.5 – 0.8
High heating value	(MJ/kg daf)	23 – 35	32 – 38.5	35 – 38	35 – 38
Low heating value	(MJ/kgraw)	6.3 – 30 – 1	26 – 32	25 – 32.3	30 – 31.4
daf = dry and ash free basis Low heating value, data from EVT Handbook 1990					

Table 4.31: Indicative analyses of typical coals (general practice)
[58, Eurelectric, 2001]

Composition of lignite and coal differs in a broad range as shown in Table 4.32. This is also true for the concentration of heavy metals and trace elements in lignite and coal. The figures given in Table 4.33 are examples from single samples from coals of different origin.

Values in mg/kg	Australia	Canada	US	Poland	Russia and CIS	Europe
Ash (%)	12.5	12.9	9.9	15.9	15.4	14.4
As	1.4	2.9	8.7	3.4	4	18.5
Ag			0.86	<1.7	<1.6	0.74
Ba			280	500	210	240
Be	1.4	0.8	1.9	1.6	0.7	2
B	12.3	58	46			
Cd	0.06	0.3	0.24	0.73	0.27	0.2
Cr	7.4	7.4	13.9	16.3	40	18.7
Cu	13.3	16.9	16.6			
Cl	300	300	800			
Co			6.2	5.3	3.2	6.2
Cs			1.92	3.3	0.9	1.3
F	62	82	55			
Hf			1.1	1.6	1.2	0.7
Hg	0.04	0.05	0.11	0.09	0.12	0.131
La			13.9	11.3	10.4	11.1
Mn	132	149	19	200	135	80
Mo	0.9	1.6	5.3	<1.1	<1.1	<0.87
Ni	9.5	7.3	10.7	<24	21	<12.5
Pb	4.8	6.8	8.6	32	12.2	9.9
Rb			16.1	23	12.3	21
Sb			1.15	1.6	0.65	1.12
Sc			5.6	5.9	6.9	5.4
Sn			<26	<62	<57	<25
Se	0.8	1.1	3.9			
Th	2.3	3.3	4.2	4.1	3	3.5
Ti	0.15	0.1	0.5			
U	0.7	1.2	1.1	1.7	1.4	1.47
V	14.8	30	23.3	38	39	43
Zn	19	8.9	14.1	<27	<6.6	<3.2
Zr			47	39	28	18.3

Table 4.32: Concentrations of heavy metals and trace elements in coals from different regions [85, Itkonen and Jantunen, 1989]

The influence of the coal quality on the performance of the combustion plant is shown schematically in Figure 4.40.

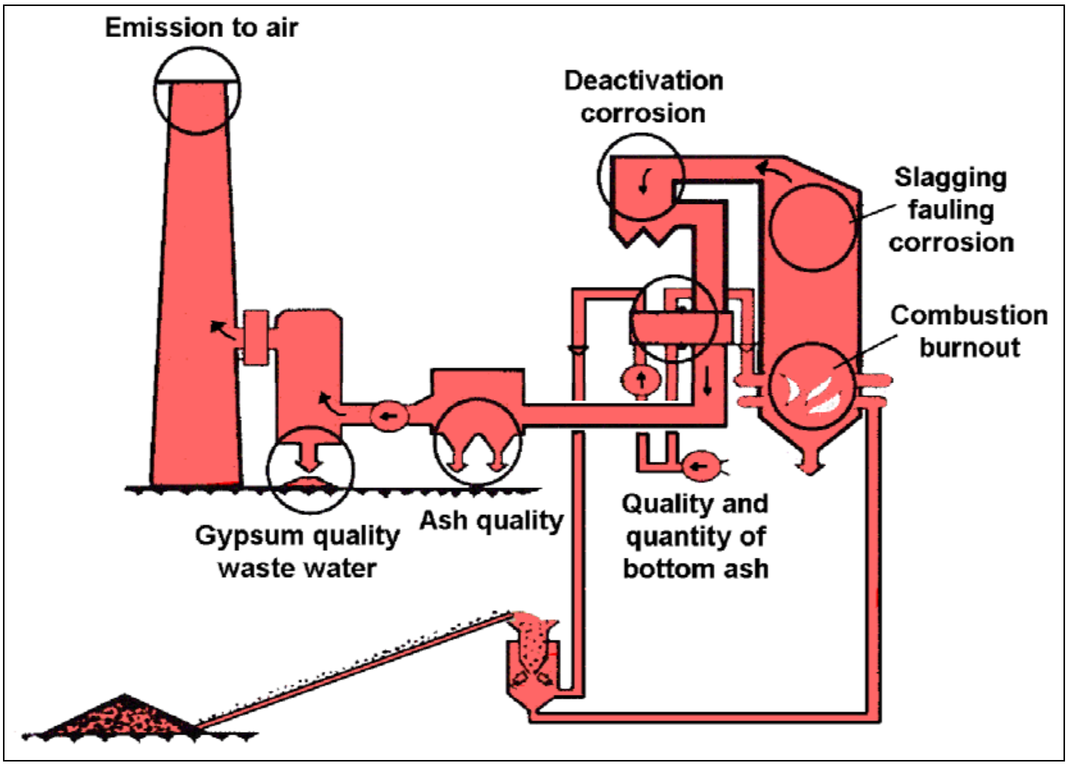


Figure 4.40: Influence of coal quality on the performance of the combustion plant

4.3.2 The efficiency of coal- and lignite-fired combustion plants

Figure 4.41 and Figure 4.42 show the total efficiency of coal-fired power plants in Europe in relation to their capacity and year of commissioning.

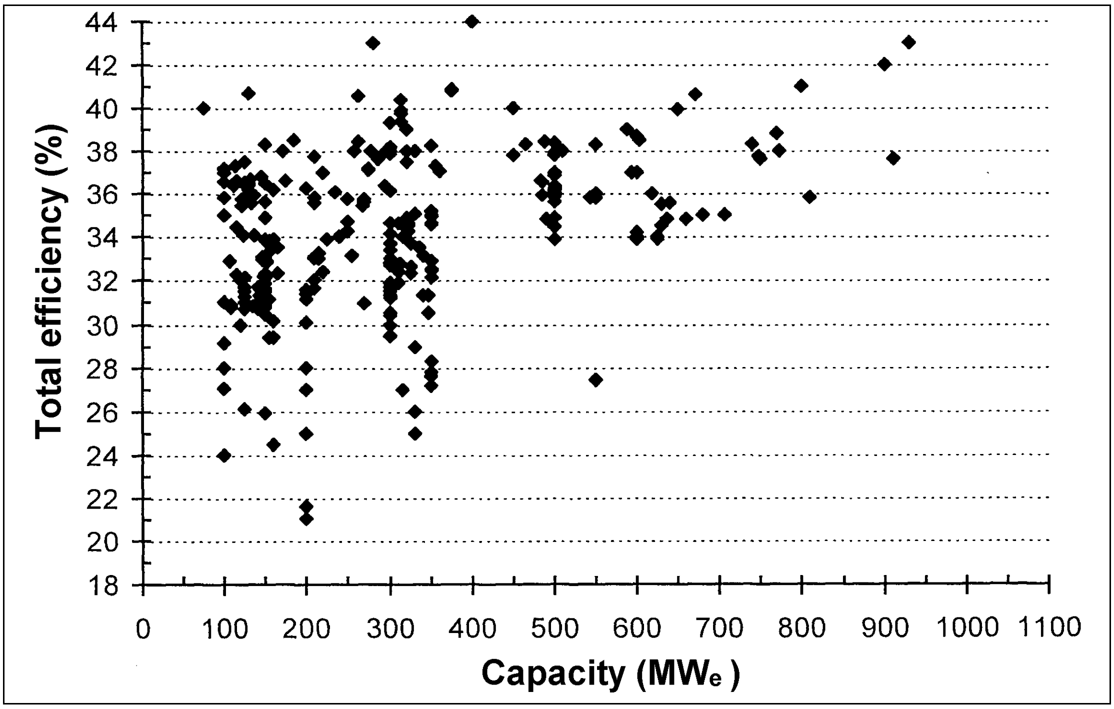


Figure 4.41: Total efficiency of coal-fired power plants in Europe in relation to capacity [110, Kakaras and Grammelis, 2000]

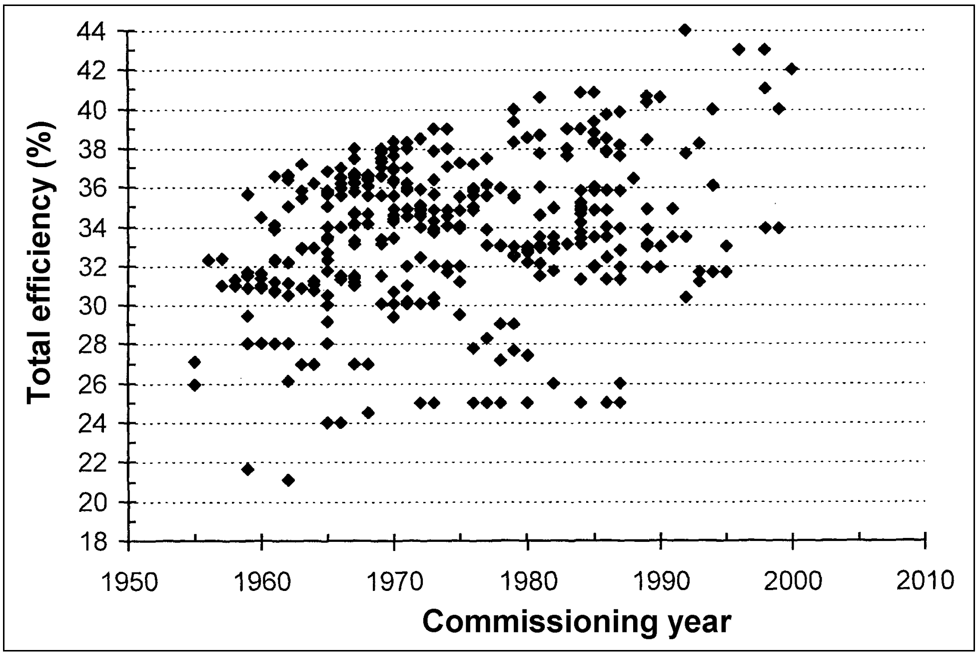


Figure 4.42: Efficiency of coal-fired power plants in Europe in relation to the commissioning year [110, Kakaras and Grammelis, 2000]

Table 4.33 shows energy efficiencies (LHV_{net}) for different types of good performing LCPs burning different types of solid fuel.

LCP technology	PC	PC	PC	PC	CFBC (retrofit)	IGCC	PBFBC (retrofit)
Electric capacity	600 MW_e	412 MW_e	412 MW_e	2 x 808 MW_e	250 MW_e	318 MW_e	
Steam pressure	180 bar	250 bar	300 bar	268 bar	163 bar	115 bar	94 bar
Steam temperature	2 x 540 °C	2 x 560 °C	3 x 580 °C	547 °C	2 x 565 °C	507 °C	513 °C
Condenser pressure	33 mbar	20 mbar	21 mbar	40 mbar	44 mar	70 mbar	44 mbar
Cooling system	Seawater	Seawater	Seawater	Cooling tower	Cooling tower	Cooling tower	
Design coal (as received)	Bituminous	Bituminous		Lignite	Lignite	Coal/pet coke	
Low calorific value (MJ/kg)	24.75	26.3	23/30	8.3 - 9.2	14.75	13.6/32.65	
Ash content (%)	16	9	5/17	8.8	28	41/0.3	
Volatile matter content (%)	35	34	20/40	22 – 48% daf.	37	19/13	
Moisture content (%)	8	9	5/14		11	12/7	
Sulphur content (%)	0.6	0.6	0.1/3	0.3 – 1.4	3.7	0.9/5.5	
Net Efficiency (LHV)	41.2 %	45.3 %	47.5 %	40 %	38.8 %	42.5 %	38.5 %

Table 4.33: Typical energy efficiencies (LHV_{net}) for different LCP technologies [58, Eurelectric, 2001]

Table 4.34 shows typical energy efficiencies (LHV_{net}) for different LCP technologies based on the same fuel (international coal HHV = 26630 kJ/kg with 1 % sulphur, 7 % moisture and 16 % ash), on the same pollutant emissions (SO_2 = 00 mg/Nm^3 - O_2=6%, NOx = 200 mg/Nm^3, dust 50 mg/Nm^3) and for different steam cycles.

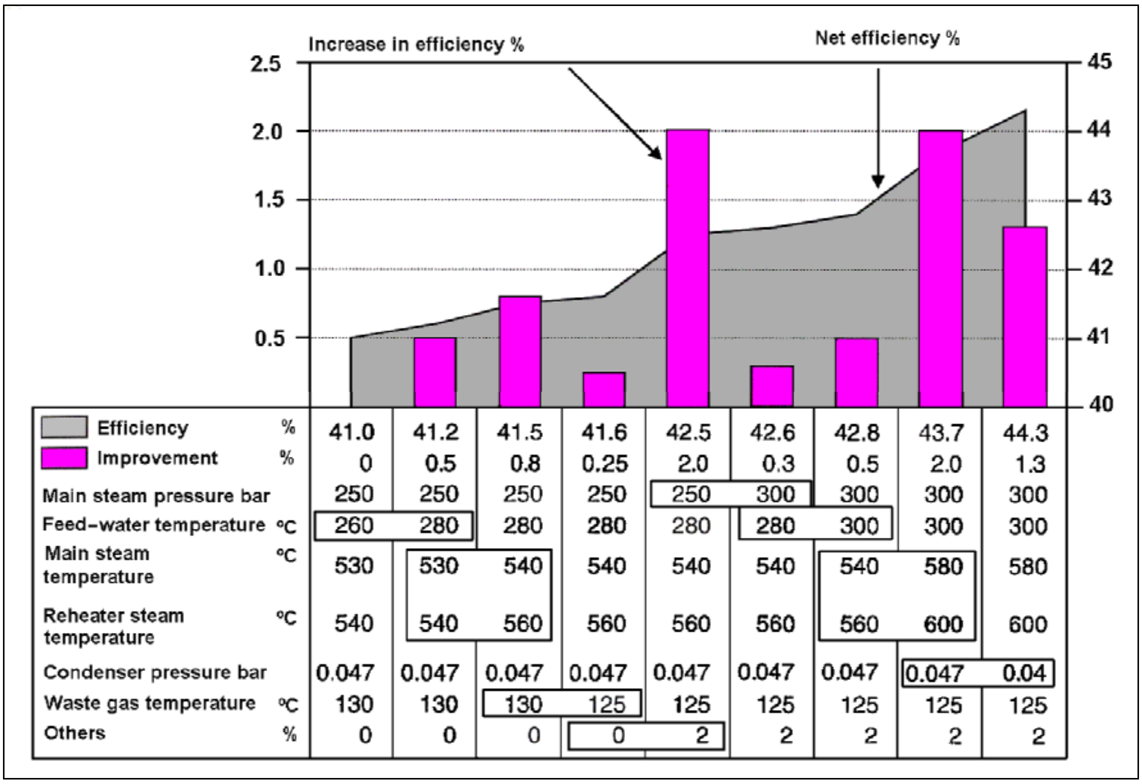
Steam pressure/temperature/ condenser pressure	PC	AFBC	IGCC	PBFBC[1]
165 bar, 2 x 565 °C, 45 mbar	38.5 %	38.0 %	44.5 % [2]	43 %
165 bar, 2 x 565°C with hot gas cleaning			47 %	
250 bar, 2 x 565 °C, 45 mbar	42.0 %	41.5 %		44.5 %
300 bar, 3 x 580 °C, 45 mbar	45.0 %	44.5 %	47.0 % [3]	45.5 %

Notes:
1. design efficiencies
2. IGCC efficiency
3 subcritical steam cycle (165 bar, 2 x 565 °C) with hot gas cleaning.

Table 4.34: Effect of the steam characteristics on efficiencies for different techniques [58, Eurelectric, 2001]

Operating conditions strongly influence the mean efficiency recorded during operation. The measured efficiency of the plant is different from the design efficiency, as operation rarely complies with ideal conditions (due to fouling, slagging, de-superheating, non-ideal condenser conditions, blowdown, etc.), and as the characteristics of the solid fuel used never comply exactly with the characteristics of the 'design solid fuel' (calorific value, ash content, etc.). Ageing of a normally maintained plant (fouling, slagging, erosion, leaks, etc.) also leads to a deterioration in efficiency over time.

More detailed information to increase the efficiency of a hard coal-fired power plant concerning the individual measurers and the material development are shown in Figure 4.43.



▨ Efficiency	%	41.0	41.2	41.5	41.6	42.5	42.6	42.8	43.7	44.3
■ Improvement	%	0	0.5	0.8	0.25	2.0	0.3	0.5	2.0	1.3
Main steam pressure	bar	250	250	250	250	250	300	300	300	300
Feed-water temperature	°C	260	280	280	280	280	280	300	300	300
Main steam temperature	°C	530	530	540	540	540	540	540	580	580
Reheater steam temperature	°C	540	540	560	560	560	560	560	600	600
Condenser pressure	bar	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.04
Waste gas temperature	°C	130	130	130	125	125	125	125	125	125
Others	%	0	0	0	0	2	2	2	2	2

Figure 4.43: Increased efficiency of a hard coal-fired power plant – individual measures [141, Benesch, 2001]

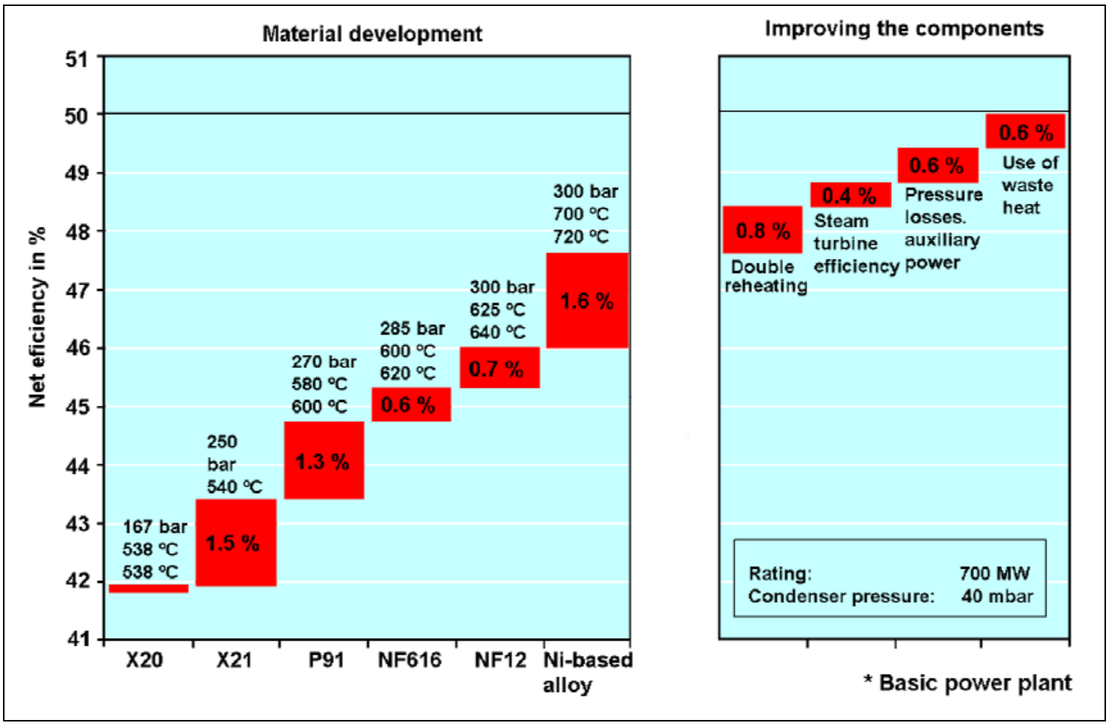


Figure 4.44: Increased the efficiency of a hard coal-fired power plant –development of materials [141, Benesch, 2001]

Other aspects that influence in the LCP efficiency are:

- **the technology used**: an IGCC, for example, intrinsically consumes more auxiliary energy (for the air separation unit, gas treatment and compressor) than a conventional boiler, even with flue-gas treatment
- **the level of pollution control:** advance FGD consumes more energy, and generally pollution control measures have a detrimental effect on efficiency
- **the design of the auxiliaries:** boiler auxiliaries have to be over-dimensioned to withstand all variations in parameters compared to their design values (i.e. for possible leaks, alternative fuels, start-up needs, redundant systems, etc.). These technical options lead to changes in energy consumption from that under normal conditions and with the fuel they were deigned for.

Boiler efficiency. For a clean and new boiler, an efficiency level of around 86 - 95 % (LHV) is currently recorded for solid fuel and cannot easily be increased. The main losses stem from flue-gas waste heat at stack, unburned carbon-in-ash, waste heat and from heat radiation losses. The effect of fuel is also important. Even assuming that the boilers have identical performance (i.e. same ambient and flue-gas temperature, same excess air, etc.), different boiler efficiencies are still obtained, and these depend on the fuel, for example (LHV basis):

- international coal: 95 % efficiency
- lignite: 92 % efficiency
- low grade lignite: 86 % efficiency.

4.3.3 Emissions to air

Table 4.35 and Table 4.52 summarise the available information on measured air emission levels (SO_2, NO_X, and N_2O, dust, CO, HF, HCl, NH_3, and heavy metals, in particular Hg) of several combustion plants mainly operated in Europe. The information given is related to certain plants and may not be valid for other plants. Eurelectric reported that with dust reduction systems, particulate emissions are reduced to 5 to 500 mg/Nm^3, depending on the efficiency of the dust reduction system.

4.3.3.1 Emissions to air from hard coal-fired combustion plants

Capacity (MW_{th})	Comb. Tech.	Emission reduction measures	Emissions to air (mg/Nm^3)							Remarks
			SO_2	NO_X	Dust	CO	HF	HCl	NH_3	
50 – 100	GF									
	PC		52 – 128	154 – 158		18 – 31	10			
	AFBC									
	PFBC	Limestone injection		214 – 257						
	PFBC	2 x 70 MWe with SCR (+district heating)	170	50		20 – 40				Fuel: 0.7% sulphur bituminous coal.
100 – 300	GF									
	PC									
	AFBC	Limestone injection at the level of secondary air	200 – 800	150 – 300	30 – 50	100 – 150				Hot-type, grate firing combustion technique
	AFBC	FF/FGD (wet)/SCR	40 - 110							
	AFBC	FGD (sds)/FF/SCR	75	322	14	5.7	0.05	0.7		
	PFBC	Limestone/SCR		43 – 114						Plant in Japan
	PFBC	Limestone/SNCR		29 – 143						
	CFBC	Limestone/ESP	100 – 200	60 – 160						
>300	PC	No abatement	2000 – 3000							1 % sulphur content standard coal
	PC	ESP/FGD(wet)/SCR	20 – 252	90 – 190	3 – 11	12 – 25	0.2 – 3	1.7 – 30	0.16 – 0.5	Dry bottom boiler Several LCPs
	PC	ESP/FGD(wet)/SCR	185	200	8	27	7	7	0.5	Wet bottom boiler
	PC	Pm/FGD (sds)/ESP/SCR	130	140	5 – 10					
	PC	Pm/FGD(dsi)/ESP	170	270	20					
	PC	Pm (LNB)/FGD(dsi)/FF	170	250	20					
	PC	Pm (reburning gas-coal)		250 - 350						
	PC	Pm (reburning coal-coal)		300 - 430						
	CFBC	limestone+ESP	100 – 200	100 – 250	30 – 50					plants in France, US and Poland

Notes:

GF (Grate firing)
PC (Pulverised coal combustion)
AFBC (Atmospheric fluidised bed combustion)
PFBC (Pressurised fluidised bed combustion)
FGD(wet) (Wet flue-gas desulphurisation)
FGD(sds) (Flue-gas desulphurisation by using a spray drier)
FGD(dsi) (Flue-gas desulphurisation by dry sorbent injection)
ESP (Electrostatic precipitator)
FF (Fabric filter)
Pm(..) (Primary measures to reduce NO_X
SCR (Selective catalytic reduction of NO_X)
SNCR (Selective non catalytic reduction of NO_X)

Table 4.35: Emissions (in concentration) to air from coal-fired combustion plants in normal operation and at constant load

Capacity (MW_{th})	**Comb. Tech.**	**Emission reduction measures**	**Electrical efficiency (%)**	**Fuel efficiency (%)**	**Specific Emissions to air (mg/MJ)**					
					SO_2	**NO_X**	**Dust**	**CO**	**HF**	**HCl**
50 – 100	GF									
	PC	ESP/DESONOX	29	80		75.4 – 80.2		9.2 – 15.2		
	AFBC									
	PFBC	Limestone				75 – 90				
100 – 300	GF									
	PC									
	AFBC	FGD(sds)/FF/SCR	25	81	26.1	111.5	5.08	1.98	0.019	0.28
	AFBC	Limestone/ESP	38	54.2						
	PFBC	Limestone/SNCR				10 – 50				
	PFBC	Limestone/SCR				15 – 40				
>300	PC	ESP/FGD(w)/SCR	32 – 44	37 – 70		34 – 97	1.1 – 5.1	4.9 – 8.3	0.08 – 1.2	0.6 – 12.3
	PC	ESP/FGD(w)/SCR	<39							
	AFBC									
	CFBC		39							

Notes:
GF (Grate firing)
PFBC (Pressurised fluidised bed combustion)
FGD(dsi) (Flue-gas desulphurisation by dry sorbent injection)
Pm(..) (Primary measures to reduce NO_X
PC (Pulverised coal combustion)
FGD(wet) (Wet flue-gas desulphurisation)
ESP (Electrostatic precipitator)
SCR (Selective catalytic reduction of NO_X)
AFBC (Atmospheric fluidised bed combustion)
FGD(sds) (Flue-gas desulphurisation by using a spray drier)
FF (Fabric filter)
SNCR (Selective non catalytic reduction of NO_X)

Table 4.36: Specific emissions to air from coal-fired combustion plants in normal operation and at constant load

4.3.3.2 Emissions to air from lignite-fired combustion plants

Capacity (MW_{th})	Comb. Tech.	Emission reduction measures	Emissions to air (mg/Nm^3)							Remarks
			SO_2	NO_X	Dust	CO	HF	HCl	NH_3	
50 – 100	GF									
	PC									
	AFBC									
100 – 300	GF									
	PC									
	AFBC	Limestone/ESP	393	168	10	0.2	0.5	4		N_2O 26 mg/Nm^3
>300	PC	Pm (LNB air and fuel staging)/ESP/FGD(wet)	77 – 341	141 – 176	2 - 13.5	4.4 – 182	0.08 – 1	0.5 – 1		Dry bottom boiler
	PC	Pm (LNB air and fuel staging)/ESP/FGD(wet)		141 – 230	2 – 50	4.4 – 250	0.5 – 10			
	PC	Pm (LNB air and fuel staging)/activated carbon filter/FGD(wet)	5	150	30	80	1	0.2		Dioxin emissions are between 1 and 30 $pgTEQ//Nm^3$ 1
	PC	ESP/FGD(wet)/SCR	230	<200	30				<10	Hard lignite
	PC	Pm (LNB air and fuel staging)/activated carbon filter/FGD(sds)	241.2	272.3	6.6	8.7	1.3	4		
	PC	Pm (combustion process-integrated) – natural DESOX ESP	300 – 450	200 – 400	50 – 100					High rate of desulphurisation effected by high alkaline ash in low rank lignites
	PC	Pm (combustion process-integrated)/ESP	2000	200 – 300	50 – 100					Low rate of desulphurisation effected by medium alkaline ash in low rank lignites
	AFBC		50 – 200	250 – 400	10 – 50					

Notes:

GF (Grate firing)
PFBC (Pressurised fluidised bed combustion)
FGD(dsi) (Flue-gas desulphurisation by dry sorbent injection)
Pm(..) (Primary measures to reduce NO_X
PC (Pulverised coal combustion)
FGD(wet) (Wet flue-gas desulphurisation)
ESP (Electrostatic precipitator)
SCR (Selective catalytic reduction of $NO_{X)}$
AFBC (Atmospheric fluidised bed combustion)
FGD(sds) (Flue-gas desulphurisation by using a spray drier)
FF (Fabric filter)
SNCR (Selective non catalytic reduction of NO_X)

Table 4.37: Emissions to air from lignite-fired combustion plants in normal operation and at constant load

Capacity (MW_{th})	Comb. Tech.	Emission reduction measures	Electrical efficiency (%)	Fuel efficiency (%)	Specific Emissions to air (mg/MJ)					
					SO_2	NO_X	Dust	CO	HF	HCl
50 – 100	GF									
	PC									
	AFBC									
100 – 300	GF									
	PC	Limestone/ESP	28	41.7	177.4	76.1	4.5	0.1	0.19	1.8
	AFBC									
>300	PC	Pm (LNB air and fuel staging)/ESP/FGD(wet)	35.7 - 41.7		5 - 112	43 - 60.4	0.09 - 5	4.9 - 25.9	0.028	0.028
	PC	Pm (LNB air and fuel staging)/activated carbon filter/FGD(wet)	37		2.16	60.36	10.7	25.86	0.43	0.088
	PC	Pm (LNB air and fuel staging)/activated carbon filter/FGD(sds)	28.9	69.1						
	AFBC									

Notes:
GF (Grate firing) **PC** (Pulverised coal combustion) **AFBC** (Atmospheric fluidised bed combustion)
PFBC (Pressurised fluidised bed combustion) **FGD(wet)** (Wet flue-gas desulphurisation) **FGD(sds)** (Flue-gas desulphurisation by using a spray drier)
FGD(dsi) (Flue-gas desulphurisation by dry sorbent injection) **ESP** (Electrostatic precipitator) **FF** (Fabric filter)
Pm(..) (Primary measures to reduce NO_X **SCR** (Selective catalytic reduction of NO_X) **SNCR** (Selective non catalytic reduction of NO_x)

Table 4.38: Specific emissions to air from lignite-fired combustion plants in normal operation and at constant load

		Coal without NO_x abatement (mg/Nm^3)	**Coal with Low NO_X burner (mg/Nm^3)**	**Lignite no abatement (mg/Nm^3)**	**Lignite with primary measures (mg/Nm^3)**
DBB	horizontal firing system	1000 – 1500	500 – 650		
	tangential firing system	600 – 900	400 – 650	400 – 700	200 – 500
	Vertical firing system	700 – 900			
WBB	cyclone firing system	1500 – 2500	1000 – 2000		

Table 4.39: Level of NO_X emissions for existing plants without secondary measures [58, Eurelectric, 2001]

4.3.3.3 Heavy metal emissions

During combustion heavy metals become volatile in metallic form as well as in the form of chlorides, oxides, sulphides etc. A large proportion of these heavy metals are condensed at temperatures of up to 300°C and separate off onto the dust particles (fly ash).

Metal	**Hard coal, dry bottom boiler (DBB)**	**Lignite, dry bottom boiler (DBB)**	**Hard coal, wet bottom boiler (WBB)**
Output (% of input): bottom ash (DBB); slag (WBB)			
As	1.6 – 7.5	0.4	10 – 21.2
Cd	1.8 – 8.9	Type of power plant	15 – 30.1
Hg	2	-	2
Pb	3.1 – 11.3	1.1	76.7 – 88.8
Output (% of input): filter fly ash (DBB)			
As	88 – 91.2	98	
Cd	89.8 – 95	96	
Hg	17 – 39	49	
Pb	81 – 94	98	
Output (% of input): gypsum resp. sewage water			
As	0.4 – 1.19	0.4	21.4 – 83.5
Cd	1.1 – 3.5	0.4	72 – 79
Hg	27 – 41	4.9	44 – 71
Pb	0.9 – 1	0.4	10 – 17.5
Output (% of input): flue-gas			
As	0.18	0.42	6.5 – 17.3
Cd	0.19	4.2	0.1 – 6
Hg	18 – 32	44	27.6 – 54
Pb	0.17	0.5	1.2 – 2.6
Note: The respective DENOX units are omitted. At these plants, ESP are used for dust abatement and the lime(stone) wet scrubbing process or the spray dryer absorption process is used for flue-gas desulphurisation			

Table 4.40: Combined heavy metal mass balances for various types of power plants

It has been shown that systems designed for flue-gas dedusting and flue-gas desulphurisation can also remove most of the heavy metals from the flue-gases, i.e. those that are not retained in the bottom ash or slag. Hence, particulate heavy metal emissions in the scrubbed flue-gas are extremely low in modern power plants equipped with flue-gas cleaning systems.

The low retention of Hg downstream of dry bottom boilers (DBB) is due to gaseous mercury being emitted in measurable quantities. In wet bottom boilers, apart from Hg, the combustion and flue-gas cleaning system also has a low retention capacity for As, so measurable quantities are emitted with the flue-gas. For flue dust (fly ash) recirculation with WBB, it can be shown that only emissions of those heavy metals with high volatility increase, e.g. Hg and especially As.

Experiments at a hard coal-fired dry bottom boiler to evaluate the effects of load and the combustion of different coals on the mass balance of heavy metals gave the following results:

- to a great extent, the amount of gaseous emissions of mercury via the flue-gas depends on the chlorine and calcium content of the coal. Chlorine has two opposing effects. It increases the share of gaseous mercury but it also improves the separation of mercury in the wet FGD, as $HgCl_2$, which can easily be washed out. Calcium improves the separation of mercury in the ESP
- the integration of heavy metals into the boiler ash does not depend on the chemical composition of the coal
- the integration of heavy metals into the fly ash does not depend on the chemical composition of the coal, but it does depend on the load of the boiler as the maximum level is reached at full load.

In Table 4.41, there is a summary of heavy metal measurements taken at three coal-fired power plants which have applied an ESP and a wet scrubber desulphurisation.

	Amount of heavy metals in different process outflows (%)			**Emission [3]**
	Removed with bottom ash and with fly ash from ESP	Removed with FGD end-product + filter cake of waste water treatment plant	Share released to the air via stack	Concentration in the emission (µg/Nm^3)
Arsenic (As)	97 – 98.7	0.5 – 1.0	0.3 – 2	0 – 5
Cadmium (Cd)	95.2 – 97.6	0 – 1.1	2.4 – 3.6 [1]	0 – 5
Chromium (Cr)	97.9 – 99.9	0 – 0.9	0.1 – 0.5	0 – 5
Mercury (Hg) [2]	72.5 – 82 [2]	0 – 16	5.1 – 13.6 [2]	0 – 5
Manganese (Mn)	98 – 99.8	0.1 – 1.7	0.1	0 – 5
Nickel (Ni)	98.4 – 99.8	0.2 – 1.4	0.1 – 0.4	0 – 5
Lead (Pb)	97.2 – 99.9	0 – 0.8	0.1 – 1.8	0 – 5
Vanadium (V)	98.4 – 99.0	0.9 – 1.3	0.2 – 0.3	0 – 5

Notes:
1 The emission of cadmium was higher in these measurements than generally reported in the literature.
2 The removal efficiency of mercury was higher and the emission lower in these measurements than is normally reported in the literature. In literature it is reported that about 20 – 30 % of the mercury is released to the air and only about 30 - 40 % is removed with ESP.
3 The emissions are indicative values, including both gaseous and particulate emissions. With good particle removal the concentrations of all heavy metals in emissions are typically below or around 1 µg/Nm^3.

Table 4.41: Pathways of heavy metals in coal-fired combustion plants
[59, Finnish LCP WG, 2000]

With IGCC, the low volatility, high boiling point metals are captured and effectively immobilised in the vitreous slag. Most higher volatility metals can be condensed and captured by syngas scrubbing.

Table 4.42 below shows the different contents of mercury in coals from different origins.

Origin	Number of samples (n)	Mean value of Hg content (mg/kg)			Variance v(%)
Indonesia	7	0.04	±	0.02	63
New Zealand	1	0.05			
Colombia	7	0.06	±	0.03	57
Russia (Kuzbass)	1	0.06			
Australia	17	0.08	±	0.06	70
Venezuela	2	0.08			
South Africa	12	0.09	±	0.02	23
Blend	36	0.09	±	0.07	72
Egypt	1	0.10			
Norway (Spitsbergen)	2	0.14			
US (eastern)	15	0.14	±	0.12	84
China	2	0.15			
Germany (Ruhr area)	1	0.16			
Poland	10	0.35	±	0.55	154

Table 4.42: Mercury content in coal from different origins
[58, Eurelectric, 2001]

Table 4.43 below shows the mercury content in the flue-gases after the electrostatic precipitator.

Number of samples (n)	Minimum value of Hg content	Maximum value of Hg content	Mean value of Hg content	Variance v(%)
Concentration of Hg in flue-gases downstream the ESP (µg/m^3)				
37	0.3	35	**4.9** +7.3/-4.6	149
percentage of Hg varorised relative to the concentration in the coal				
36	1.0	115	**43** ± 30.1	69

Table 4.43 Mercury content in flue-gases downstream of the ESP
[58, Eurelectric, 2001]

Table 4.44 gives an overview of measured N_2O emission levels taken out of different literature sources

Fuel	Comb Tech.	O_2 (%)	N_2O (mg/Nm^3)					N_2O (kg/TJ)	
			Kremer 1994	KEMA 1993	VGB 1994	IEACR 1993	Braun 1993	IACR 1993	Peter 2001
Coal	PC (DBB)	6	<2	<4 Without staged combustion <0.4 – 1.2 With staged combustion		1 – 20		0.4 – 1.4	2 – 5
	PC (WBB)	6	3.8 – 9		4 – 10			0.4 – 1.4	2 – 5
	Grate firing		<30		1 – 10	0.2 – 3		0.4 – 1.4	2 – 5
	CFBC	7	4 – 20 (partial load) 40 – 700 (full load)	16 – 170 (790 – 940 °C)	30 – 160	60 – 140	50 – 120 (with peaks up to 380)	36 - 72	20 – 45
	BFBC	7	100 – 150 (partial load) 140 – 480 (full load)						
Lignite	PC (DBB)	6	10 – 16		13	1.5 – 6		0.6 – 2.3	0.8 – 3.2
	Grate firing	6	<30			0.8 – 2.5			0.8 – 3.5
	FBC	7	<30		5 – 20	10 – 90	5 - 14 (with peaks up to 30)	11 – 45	3 – 8

Table 4.44: Measured N_2O emission levels taken from different literature sources [98, DFIU, 2001]

Table 4.45 and Table 4.46 show emissions of halogenated acids, dioxins and PAH from different coal and liquid fuel power stations.

Fuel: hard coal	HCl mg/Nm³, 6 % O_2	HF mg/Nm³, 6 % O_2
No desulphurisation	100 – 450	4 – 28
FGD + contact transfer by regenerative air heater	3 – 14	2 – 8
FGD no transfer by air air heater	1 – 8	0.2 – 2
FBC + dry lime addition*	50 – 170	0.5 – 4
Note: *Higher SO_2 reduction increases emitted HCl part		

Table 4.45: Emission levels of HCl and HF for plants with and without secondary measures [58, Eurelectric, 2001]

Substance	Coal	Heavy oil	Orimulsion
Dioxins and furans	2.193 pg/Nm^3	2.492 pg/Nm^3	2.159 pg/Nm^3
PAH	0.0606 µg/Nm^3	0.0507 µg/Nm^3	0.0283 µg/Nm^3

Table 4.46: Emission levels of dioxin and PAH from the combustion of different fuels [192, TWG, 2003]

4.3.4 Emissions to water from hard coal-fired combustion plants

Combustion Technique	Waste water origin	Waste water treatment	Concentration in waste water (mg/l)						
			Hydrazine	Filterable matter	Sulphate	Sulphite	Fluoride	Hg	Sulphide
GF									
PC	Wet FGD (dry bottom boiler	Fil/Pre/Floc/Sed/Neu		30	2000	20	30	0.05	0.2
	Wet FGD (dry bottom boiler	Fil/Pre/Floc/Sed/Neu		155	2667	26.7	172	0.034	
	Wet FGD, high thickening in water circuit, partly re-used for cooling	Fil/Pre/Floc/Sed/Neu		17	2542	2	8	0.007	0.07
	Treatment of condensate and feed-water	Neu/Sed	2	50					
	Treatment of condensate and feed-water and water from DESONOX	Neu					5.45	0.01	0.01
ACFBC	Treatment of condensate and feed-water	Neu/Sed	344						

Notes

Fil	Filtration	Pre	Precipitation	Floc	Flocculation	Sed	Sedimentation	Neu	Neutralisation

Table 4.47: Emissions to water from coal-fired combustion plants

Combustion Technique	Waste water origin	Waste water treatment	Spec. waste water flowrate (m^3/MW_{th})	Concentration in waste water (mg/l)										
				Cl	**AOX**	**COD**	**P**	**N**	**Zn**	**Cr**	**Cd**	**Cu**	**Pb**	**Ni**
GF														
PC	Wet FGD (dry bottom boiler	Fil/Pre/Floc/Sed/Neu	0.051		0.038	71		10	1	0.01	0.01	0.01	0.1	0.02
	Full water softening system	Neu/Sed	0.0029		0.184		0.016	19.2	0.06	0.026	0.00008	0.026	0.0016	0.064
	Wet FGD, high thickening in water circuit, partly re-used for cooling	Fil/Pre/Floc/Sed/Neu	0.0079	40000		150			1	0.5	0.05	0.5	0.1	0.5
	Treatment of condensate and feed-water	Neu/Sed	0.0073					1						
	Treatment of condensate and feed-water and water from DESONOX	Neu	0.0286	2940					0.05	0.006	0/0006	0.005	0.005	0.006
ACFBC	Treatment of condensate and feed-water	Neu/Sed	0.62	34.4	34.4	13778	517							

Notes

Fil	Filtration	Pre	Precipitation	Floc	Flocculation	Sed	Sedimentation	Neu	Neutralisation

Table 4.48: Emissions to water from coal-fired combustion plants

Table 4.51 and Table 4.52 shows the emission from eight different coal power plants.

Parameters	Unit	Plant A	Plant B	Plant C	Plant D
Temperature	°C		18	28.7	
pH		7.61		7.8	6.9 – 7.9
As	mg/l		0.001	<0.005	
Sb	mg/l				
Pb	mg/l	<0.01	0.03	<0.05	
Fe	mg/l	0.07			0.2 – 0.5
Cr	mg/l	0.01	0.03	<0.05	
Cd	mg/l		0.003	<0.005	
Co	mg/l		0.002		
Cu	mg/l	<0.01	0.003		
Ni	mg/l	<0.01	0.03		
TI	mg/l		0.031		
V	mg/l		0.073		
Mn	mg/l		0.03		
Hg	mg/l		0.0001	<0.001	
Zn	mg/l	<0.02	0.05		
Sn	mg/l	<0.05	0.001		
F	mg/l		0.1		
Cl	mg/l		400		
BOD	mg/l				10 – 28
COD	mg/l	11.7 kg/d***			10 – 65
Suspended solids	ml/l				<0.1
Total P	mg/l		0.15		
Sulphate as SO_4	mg/l	1376	1215		
Sulphide as S	mg/l		0.1		
Sulphite as SO_3	mg/l		10.2		
Total N	mg/l		76.6		
NH_4 as N	mg/l	7	0.85		
Nitrite - N	mg/l	2.1			
TOC as C	mg/l		8.6		

Table 4.49: Emissions to water from four different coal-fired combustion plants [192, TWG, 2003]

Parameters	**Plant E**	**Plant F**	**Plant G**	**Plant H**
			Min Max	**Min Max**
pH	7.9		6.7 - 8.6	
Temperature	27.3 °C	30 °C	11.8 - 21.2 °C	
Colour			2 - 7	0 – 5
Conductivity			724 – 6850	2.940 – 5.470
Suspended solids				1.6 – 9.2
pH				7.1 – 8.5
Ca			57.8 - 714	
K			2.2 – 37.9	
Mg			1.4 – 23.0	
Na			42.7 - 985	
Fe			n.n – 0.35	
As	<0.005	0.02		n.n. – 0.007
Pb	<0.05	0.02		n.n.
Cd	<0.005	0.4		n.n.
Cr	<0.05			
Cu		0.1		n.n – 0.007
Mn		3		n.n. – 0.020
Hg	<0.001	0.001		n.n.
Zn		0.4	n.n – 0.037	n.n. – 0.054
Ammonia - N			0.78 – 7.04	0.11 – 8.90
Nitrite – N			n.n – 0.67	0.02 – 0.95
Nitrate – N			2.7 – 26.9	10.0 – 59.4
Total N			3.5 – 29.1	13.1 – 65.9
Total P			0.03 – 0.27	0.01 – 0.23
Chloride			87 – 1761	123 - 733
Sulphide				n.n.
Sulphite				n.n.
Sulphate			57 – 1042	1414 – 2341
TOC			1 – 5	2 - 14
COD			9 – 37	9 - 56
BOD_5			1 - 19	
Hydrazine				n.n.
Cyanide				n.n.
Fluoride				n.n. – 2.0.
Antimony				n.n.
Arsenic				n.n. – 0.007
Chromium				n.n. – 0.005
Cobalt				n.n.
Nickel				n.n. – 0.123
Thallium				n.n.
Vanadium				0.013 – 0.395
Zinc				n.n.
n.n: below detection limit **Min:** minimum value obtained **Max:** maximum value obtained				

Table 4.50: Emissions to water from four different coal-fired combustion plants [192, TWG, 2003]

4.3.5 Emissions to water from lignite-fired combustion plants

Combustion Technique	Waste water origin	Waste water treatment	Concentration in waste water (mg/l)					
			Filterable matter	Sulphate	Sulphite	Fluoride	Hg	Sulphide
PC	Wet FGD	Fil/Pre/Floc/Sed/Neu	7	1300	0.5	1.5		
	Wet FGD (dry bottom boiler	Fil/Pre/Floc/Sed/Neu						
	Treatment of condensate and feed-water	Neu/Sed	10	348				0.8
	All waste water from power plant and lignite yard	Sed/pH adjustment/Pre/Floc/Sed/Neu	20	1700				

Notes
Fil Filtration Pre Precipitation Floc Flocculation Sed Sedimentation Neu Neutralisation

Table 4.51: Emissions to water from lignite-fired combustion plants

Combustion Technique	Waste water origin	Waste water treatment	Spec. waste water flowrate ($m^3/h – MW_{th}$)	Concentration in waste water (mg/l)										
				Cl	AOX	COD	P	N	Zn	Cr	Cd	Cu	Pb	Ni
PC	Wet FGD (dry bottom boiler	Fil/Pre/Floc/Sed/Neu	0.005											
	Treatment of condensate and feed-water	Neu/Sed	0.0073					1						
	Cooling water	none	0.066 – 0.350		0.03 – 0.08	17.2 – 27.8	0.15 – 0.32	2.1 – 22.8	0.06	0.03			0.004 – 0.03	

Notes
Fil Filtration Pre Precipitation Floc Flocculation Sed Sedimentation Neu Neutralisation

Table 4.52: Emissions to water from lignite-fired combustion plants

4.3.6 Combustion residues and by-products

Large quantities of mineral substances are produced in every power plant. For a 750 MW_e power plant burning one million tonnes of coal with an ash content of, e.g. 10 % and a sulphur content of, e.g. 1 %, some 154000 tonnes of coal combustion products (CCPs) are yielded annually. Currently, nearly 500 million tonnes of coal ashes (bottom ash and fly ash) are being produced per year worldwide. In many countries (for example – Austria, Canada) there is major concern about the heavy metal content of these residues, which adversely affect soil quality.

Gypsum:

- **main component:** calcium sulphate-dihydrate, can contain fly ash and comparable higher concentrations of Hg and Se
- **critical parameters for use in the construction industry:** crystal size, crystallisation and water content.

Fly ash: contains the largest part of condensed heavy metal:

- **critical parameters for use in concrete**: ignition loss, Cl, free CaO;
- **critical parameters for use in cement:** physical, chemical, mechanical parameters of cement are regulated (EN-197-1): ignition loss, sulphates, Cl.

Bottom ash: low heavy metal content; use in the brick and cement industry

Residue from spray dry absorption: mixture of gypsum, calcium-sulphite and fly ash; the major part is landfilled or used as a sealing material for landfills

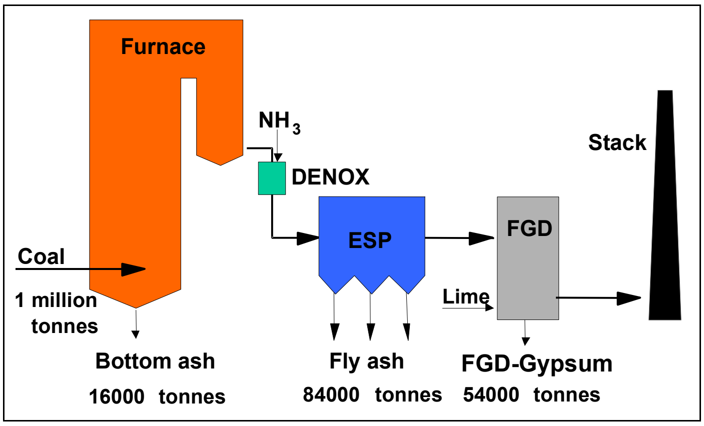


Figure 4.45: Annual Production of CCPs in a 750 MW_e coal-fired power plant at 6000 hours full load (total production of CCPs = 154000 tonnes)
[90, ECOBA v. Berg, 1999]

According to [90, ECOBA v. Berg, 1999], the amount of CCPs produced in the EU-15 power plants totals 55 million tonnes. Figure 4.46 shows the shares of the different CCPs produced in 1999. Almost 70 % of the total CCPs are yielded as fly ash. All combustion residues add up to 85.1 % and FGD residues up to 13.9 % by mass.

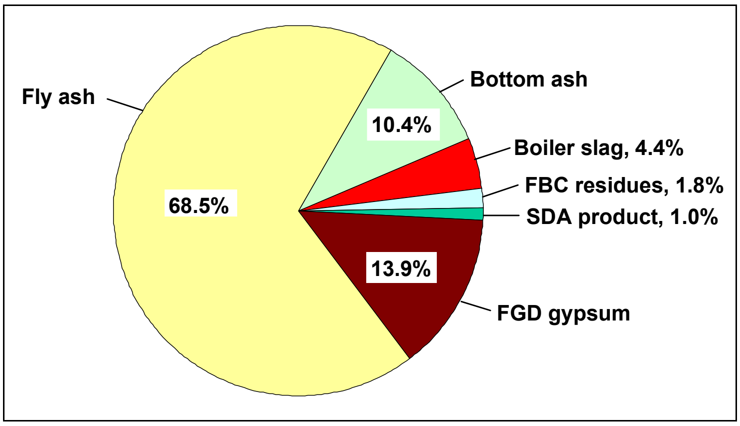


Figure 4.46: Production of CCPs in the EU-15 in 1999
[90, ECOBA v. Berg, 1999]

Most of the CCPs produced were used in the building industry, in civil engineering, and as construction materials in underground mining (55.3 %) or for the restoration of open cast mines, quarries and pits (33.2 %). In 1999, only 2.2 % were temporarily stockpiled for future use and 9.3 % were disposed of (Figure 4.47).

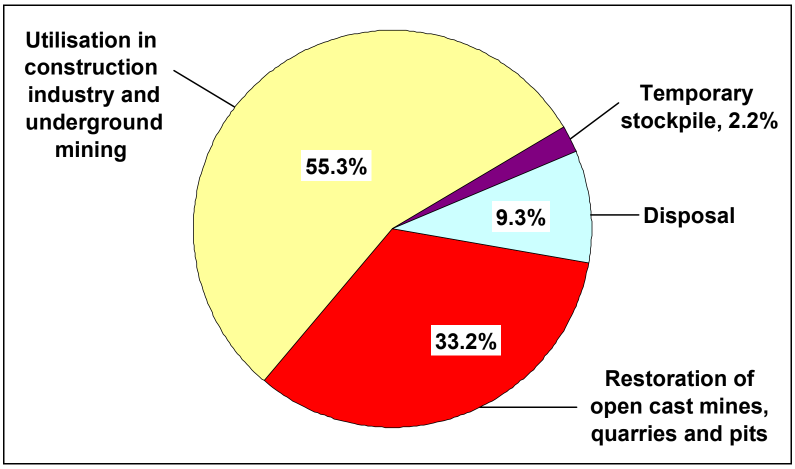


Figure 4.47: Utilisation and disposal of CCPs in the EU-15 in 1999
[90, ECOBA v. Berg, 1999]

CCP utilisation varies between Member States, since climate, taxes and the legal situations also vary. In some EU-15 countries the utilisation rate for CCPs is nearly 100 %, whereas in other countries the utilisation rate will not exceed 10 % due to existing unfavourable conditions, such as heavy metal content, loss of ignition, free and total Ca content, Cl, etc.

The utilisation of desulphurisation products also varies within the EU-15. In some countries, spray dry absorption (SDA) products are utilised in the construction industry and as fertiliser, in other countries it is disposed of. The FGD gypsum is utilised for the production of plasterboards and self-levelling floor screeds, as well as a retarder for cement. The observed development in utilisation rates is caused by a general acceptance of the materials as products. This improvement has been achieved by research activities, practical experience and by marketing efforts.

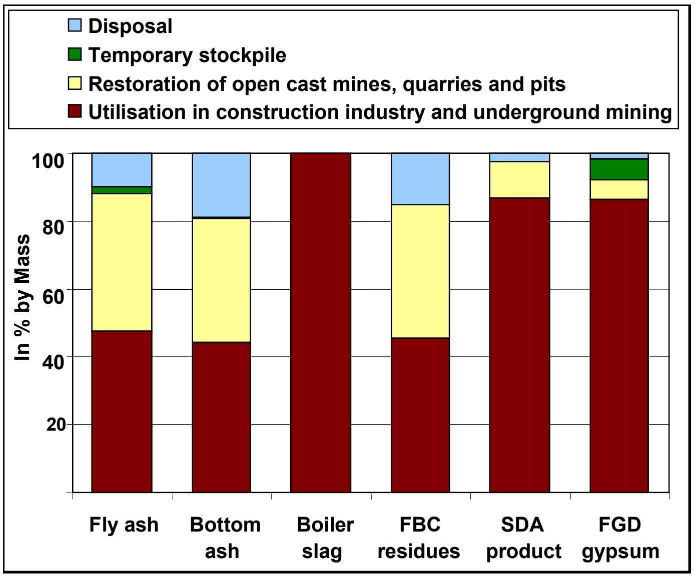
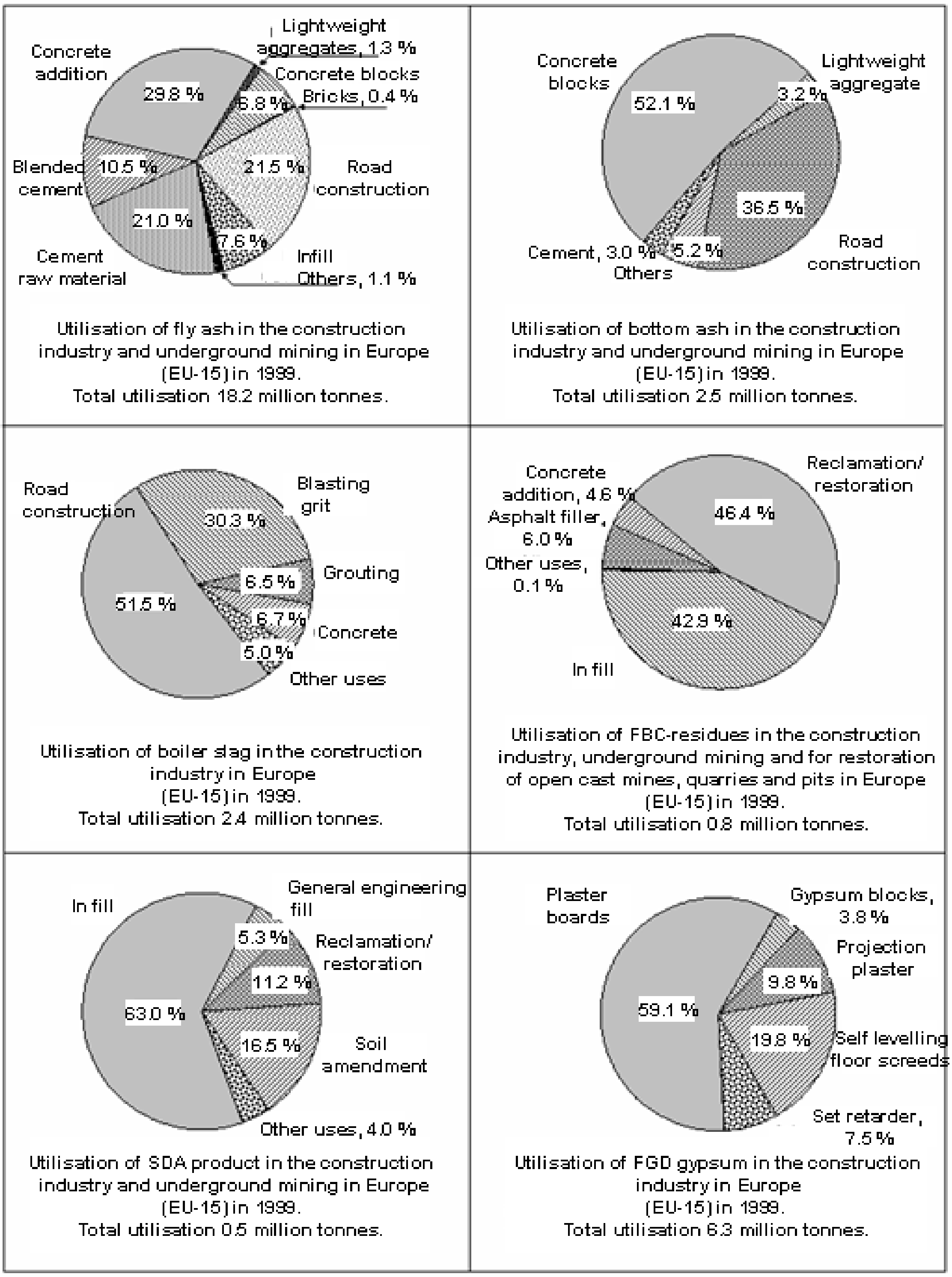


Figure 4.48: Utilisation and disposal of CCPs in the EU-15 in 1999
[90, ECOBA v. Berg, 1999]

The rates for utilisation and disposal of different CCPs in 1999 are shown in Figure 4.48. In 1999, as much as 45 to 48 % of the combustion residues were utilised in the construction industry and in underground mining, 37 to 41 % in the restoration of open cast mines, quarries and pits, up to 2 % were stockpiled, and between 10 and 15 % were disposed of.

Nearly 86 % of both SDA product and FGD gypsum were utilised in the construction industry and in underground mining. For the restoration of open cast mines, quarries and pits 11 % of the SDA product and nearly 6 % of FGD gypsum were used, and nearly 6 % of the FGD gypsum is stored in temporary stockpiles for future use. Only very small amounts of the CCPs had to be disposed of [90, ECOBA v. Berg, 1999].

An overview of the different fields of utilisation of the individual CCPs is given in Figure 4.49.



Utilisation of fly ash in the construction industry and underground mining in Europe (EU-15) in 1999.
Total utilisation 18.2 million tonnes.

Utilisation of bottom ash in the construction industry and underground mining in Europe (EU-15) in 1999.
Total utilisation 2.5 million tonnes.

Utilisation of boiler slag in the construction industry in Europe (EU-15) in 1999.
Total utilisation 2.4 million tonnes.

Utilisation of FBC-residues in the construction industry, underground mining and for restoration of open cast mines, quarries and pits in Europe (EU-15) in 1999.
Total utilisation 0.8 million tonnes.

Utilisation of SDA product in the construction industry and underground mining in Europe (EU-15) in 1999.
Total utilisation 0.5 million tonnes.

Utilisation of FGD gypsum in the construction industry in Europe (EU-15) in 1999.
Total utilisation 6.3 million tonnes.

Figure 4.49: Overview of CCP utilisation in the EU-15 in 1999
[90, ECOBA v. Berg, 1999]

The heavy metal content of some ashes and other combustion by-products are presented in Table 4.53 and Table 4.54.

Heavy metal	Concentration (ppm)			Mass stream (g/h)		
	Coal	Coarse ash	Fly ash	Coal	Coarse ash	Fly ash
Arsenic	10.8	12.0	43.9	3193.6	43.2	3042
Cadmium	0.07	0	0.295	20.7	0	20.4
Chromium	39.1	204.7	154.5	11561.9	736.7	10703.4
Copper	16.0	63.2	67.6	4716.4	227.5	4684.7
Lead	6.7	11.6	27.7	1981.2	41.8	1919.6
Mercury	0.28	0	0.1	81.3	0	6.9
Nickel	40.5	204.0	158.7	11961.1	734.4	10997.9
Selenium	0.99	0.6	1.4	291.3	2.2	97.0
Vanadium	41.3	94.7	169.0	12197.6	340.9	11711.7
Zinc	26.1	38.1	116.1	7717.8	137.0	8076.9

Table 4.53: Heavy metals of coal and some coal combustion residues (this data should be seen as examples because the variability is very highly dependent on the type of coal and installation) [64, UBA, 2000]

	Input (%)		Output (%)				
	Coal	Chalk $CaCO_3$	Fly ash	Coarse ash	Gypsum	Clean gas	Dust (emit.)
Arsenic	100.0	0.0	99.1	0.4	0.4	<0.1	<0.1
Cadmium	100.0	0.0	95.5	0.0	0.4	4.1	0.0
Chromium	99.6	0.4	91.2	5.1	3.6	0.1	0.0
Copper	98.9	1.1	94.3	3.6	0.8	1.4	<0.1
Lead	99.6	0.4	98.0	1.1	0.4	0.5	<0.1
Mercury	99.1	0.9	50.2	0.0	5.0	44.8	0.0
Nickel	97.3	2.7	88.7	10.8	0.2	0.1	0.2
Selenium	100.0	0.0	51.7	0.6	27.9	16.4	3.4
Vanadium	99.7	0.3	97.8	1.8	0.3	0.0	0.1
Zinc	99.5	0.5	97.7	0.8	0.6	0.8	<0.1
Note: Output based on 100 % input of the metal element and chalk in relation to the output							

Table 4.54: Input and output of metals in coal-fired combustion plants (this data should be seen as examples because the variability is very highly dependent on the type of coal and installation) [64, UBA, 2000]

4.3.7 Noise emissions

The information on general noise from power plants is described in Section 3.12
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4.4 Techniques to consider in the determination of BAT for the combustion of coal and lignite

This section presents techniques that have been considered in the determination of BAT for the preventing or reducing emissions and for increasing the thermal efficiency. They are all currently technically and commercially available. In this chapter, techniques to be considered have only been described in a general way, but for most of the techniques, more detailed descriptions are presented in Chapter 3 and for some techniques examples are given in Section 4.2 to demonstrate in detail the environmental performance of these techniques when applied in a real situation. In principle, the general techniques described in Chapter 3 also apply, to a large extent, to the combustion of coal and lignite and should in general also be seen as techniques to consider in the determination of BAT. For more detailed descriptions, refer to Chapter 3.

To avoid duplication throughout this document, refer to Environmental Management Systems (EMS) in Section 3.15.

4.4.1 Techniques for the unloading, storage and handling of fuel

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Transport and handling of coal and lignite							
Closed transfer conveyors with dedusting equipment	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	Limited by water content
Open conveyors with wind shields	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	
Unloading equipment with adjustable height	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	
Cleaning devices for conveyor belts	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	Limited by water content
Enclosed storage of lime/limestone in silos with dust abatement	Reduction of fine particles	Possible	Possible	High	None	Not available	
Storage of coal, lignite and additives							
Water spray systems	Reduction of fugitive dust emissions	Possible	Possible	High	Water contamination	Cost for water spraying and drain collection	
Sealed surfaces with drainage systems	Prevention of soil and groundwater contamination	Possible	Possible	High	None	Cost for waste water treatment	Collected drainage water needs to be treated in a settling pond
Wind shields	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	
Storage of pure liquified ammonia		Possible	Possible	High	High safty risk	High investment and operation costs	
Storage of ammonia as ammonia-water solution		Possible	Possible	High	Less safety risk than of storage as pressurised liquid ammonia	Not available	Higher safety

Table 4.55: Techniques to be considered for the unloading, storage and handling of fuel

4.4.2 Techniques for fuel pretreatment

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Fuel switch	Better environmental profile of fuel (low sulphur, low ash content	Not practised	Depends on the design characteristics of the specific boiler	High	Lower impurities in the coal leads to less emissions. Low ash content involves a PM emission reduction and a reduction of solid wastes for utilisation/disposal	The fuel price might be higher	The possibility of changing the fuel may be limited because of long-term delivery contracts or full dependence on local mines
Coal blending and mixing	Avoiding emission peaks	Possible	Possible	High	Stable operation		
Coal washing	Reduction of leachable impurities	Possible	Possible	High	Lower impurities in the coal leads to less emissions	Additional cost of coal washing plant	Usually coal washing is practised directly on the mining site
Lignite pre-drying	Increased efficiency of approximately 3 – 5 percentage points	Possible	Possible	Limited experience because only applied as pilot plant	Increased efficiency	Additional cost of lignite dryers	Large size lignite driers have not been built to date
Coal gasification	Increased plant efficiency and lower emission levels particularly for NO_X	Possible but until now only applied in demonstration plants	Not possible	Only applied in demonstration plants		Not available for normal operation	In the medium term, gasification has the potential to constitute a viable alternative to normal combustion, particularly in view of the expected electrical efficiencies of 51 – 55 %.

Table 4.56: Techniques to be considered for fuel pretreatment

4.4.3 Techniques to increase efficiency and fuel utilisation

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Energetic optimisation of plant equipment							
Co-generation of heat and power (CHP)	Increased fuel utilisation	Possible	Very limited	High			Depending on site-specific demands for heat loads
Changing turbine blades	Increased efficiency	Possible	Possible	High	None	Not available	Steam turbine blades can be changed to three-dimensional blades during regular maintenance intervals
Using advanced materials to reach high steam parameters	Increased efficiency	Possible	Not possible	Practised in new plants	None	Not available	The use of advanced materials allows steam pressures of 300 bar and steam temperatures of 600 °C
Supercritical steam parameters	Increased efficiency	Possible	Not possible	Practised in new plants	None	Not available	
Double reheat	Increased efficiency	Possible	Not possible	Practised mainly in new plants	None	Not available	
Regenerative feed-water heating	Increased efficiency	Possible	Not possible	Practised in new plants and some existing ones	None	Not available	New plants use up to 10 stages, resulting in a feed-water temperature of about 300 °C
Advanced computerised control systems	increased efficiency higher boiler performance reduced emissions	Possible	Possible	High	None	Not available	
Use of the heat content of the flue-gas for district heating	Increased fuel utilisation	Possible	Possible	High	None	Not available	Lowest possible temperature of the cooling water

Table 4.57: Techniques to be considered to increase efficiency and fuel utilisation

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Combustion parameters to optimise							
Low excess air	Increased efficiency and reduced NO_X and N_2O emissions	Possible	Possible	High	No	not available	Can increase the tube failure risk and the amount of unburned fuel
Lowering of exhaust gas temperatures	Increased efficiency	Possible	Possible	High	Corrosion, blocking of airheater	not available	Exhaust gas temperature should be 10 – 20 °C above acid dew point. The extra heat can be used only as secondary heat
Low unburned carbon-in-ash	Increased efficiency	Possible	Possible	High	Reduction of NO_X emissions leads to higher unburned carbon-in-ash	not available	The emission of NO_X and the amount of unburned carbon-in-ash needs to be optimised, but the higher priority pollutant is NO_X
Low CO concentration in flue-gas	Increased efficiency	Possible	Possible	High	Low NO_X emissions leads to higher CO levels	not available	The emission of NO_X and CO needs to be optimised, but the higher priority pollutant is NO_X
Flue-gas cleaning and discharge							
Cooling tower discharge	Reheating of flue-gas after the FGD plant is not necessary	Possible	Possible	High	No stack is needed	No additional cost for constructing and maintenance of a stack	The feasibility of cooling tower discharge has to be assessed in a case-by-case basis (e.g. availability of cooling tower and respective location and construction materials)
Wet stack technique		Possible	Possible	High	Visible plume		
Cooling system							
Various techniques							See cooling BREF

Table 4.58: Techniques to be considered to increase efficiency

4.4.4 Techniques for the prevention and control of dust and particle-bound heavy metal emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
ESP	Reduction of particulate emissions. The removal of heavy metals and Hg is a positive but minor side effect	Possible	Possible	High	None	Costs from EUR 13 – 60 per kW are reported. The figures do not include investment costs for the collected ash handling and transportation systems, which for high ash content lignite are significantly high	The ESP is the better economic solution, especially for larger size plants Particle–bound mercury is attached to solids, so it can be readily captured in an ESP. In the case of sub-bituminous coals and lignites, the removal of Hg is low due to the high alkalinity of the fly ash and low level of HCl in the flue-gases
Fabric Filter	Reduction of particulate emissions particularly fine dust (PM 2.5 and PM 10) The removal of heavy metals and Hg is a positive but minor side effect	Possible	Possible	High	The efficiency of the power plant will be reduced by 0.1 percentage points	Operating and maintanance costs are higher than by an ESP	In coal-fired combustion plant fabric filters are mainly used downstream of dry and semi-dry techniques to reduce SO_2 emissions Particle–bound mercury is attached to solids, so it can be readily captured in an FF. In the case of sub-bituminous coals and lignites, the removal of Hg is low due to the high alkalinity of the fly ash and low level of HCl in the flue-gases
Cyclones	Reduction of particulate emissions	Possible	Possible	High	Very limited reduction of fine particles	Low investment costs	Mechanical cyclones can only be taken as pre-deduster with other techniques such as ESP of FF
Addition of activated carbon in FGD	Reduction of Hg emissions	Possible	Possible	Limited		Addition of activated carbon in FGD has low investment and operation costs	Addition of activated carbon in FGD still has the uncertainty of raising the mercury content of the gypsum

Table 4.59: Techniques to consider for the prevention and control of dust and heavy metal emissions

4.4.5 Techniques for the prevention and control of SO_2 emissions

Technique	**Environmental benefit**	**Applicability**		**Operational experience**	**Cross-media effects**	**Economics**	**Remarks**
		New plants	**Retrofitable**				
Primary measures							
Use of low sulphur fuel	Reduction of SO_2 emissions at source	Possible	Possible	High	Possible increase in dust and NO_X emissions	Depends on the fuel	Possible increase in dust and NO_X emissions
FBC boiler	Reduction of SO_2 and NO_X emissions	Possible	Very limited	High	Higher emissions of N_2O	Plant specific	

Table 4.60: Techniques to consider for the prevention and control of SO_2 emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Secondary measures							
Wet lime/limestone scrubber with gypsum production	Reduction of SO_2, HF, HCl, dust, Hg and Se emissions Retrofitting of existing plants with FGD provides co-benefits in the control of fine dust and Hg	Possible but rarely applied in plants below 100 MW_{th}	Possible	High	Because of the used source of lime, the emissions of As, Cd, Pb and Zn might be slightly higher. Increases CO_2 emissions Waste water emissions	Plant specific	Because of the high costs of the wet scrubbing process, this technique is, for larger size plants, the more economic solution. The existing wet scrubber can be improved by optimising the flow pattern in the absorber. Gaseous Hg^{2+} compounds of coal flue-gas are weakly to strongly soluble, and the more-soluble species can generally be captured in wet FGD scrubbers
Seawater scrubber	Reduction of SO_2, HF, HCl, dust, and Hg emissions Retrofitting of existing plants with FGD provides co-benefits in the control of fine dust and Hg	Possible	Possible	High	Tendency of reduced pH-levels in the vicinity of the water discharge and emission of heavy metal and remaining ash to the marine environment	Plant specific	The use of a seawater scrubber is strongly dependent on the specific situation because of the pollution impact to the marine environment Gaseous Hg^{2+} compounds of coal flue-gas are weakly to strongly soluble, and the more-soluble species can generally be captured in wet FGD scrubbers
Other wet scrubber types	Reduction of SO_2	Possible, but rarely in new plants	Depends on the individual plant	Very limited	depends on the technique	Not available	The reduction of other pollutants depends on the specific technique
Spray dry scrubber	Reduction of SO_2, HF, HCl, dust, and Hg emissions The retrofitting of existing plants with FGD provides co-benefits in the control of fine dust and Hg	possible	Possible	High	Residues that need to be landfilled. Reduction in overall LCP efficiency	Plant specific	Gaseous Hg^{2+} compounds of coal flue-gas can generally also be captured in spray dry FGD scrubbers, in particular in combination with a FF
Sorbent injection	Reduction of SO_2, HF, HCl, dust	Possible	Possible	High	Residues that need to be landfilled	Not available	
Others	Reduction of SO_2, and in the combined technique also of NO_X	Possible, but rarely in new plants	Depends on the individual plant	Very limited			The reduction of other pollutants depends on the specific technique

Table 4.61: Techniques to consider for the prevention and control of SO_2 emissions

4.4.6 Techniques for the prevention and control of NO_X and N_2O emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Primary measures							
Low excess air	Reduction of NO_X, and N_2O emissions, increased efficiency	Possible	Possible	High	Trend to higher unburned carbon-in-ash Low excess air tends to give higher CO and HC levels	Plant specific	Risk of tube and wall corrosion
Air-staging (OFA, BBF and BOOS)		Possible	Possible	High	Tendency to lead to higher unburned carbon-in-ash	Plant specific	
Flue-gas recirculation		Possible	Possible	High		Plant specific	For existing plants, the applicability depends on the individual plant
Low NO_X burners	Reduction of NO_X	Possible	Possible	High	Tendency to lead to higher unburned carbon-in-ash		For existing plants, the applicability depends on the individual plant. Often includes flue-gas recirculation and air staging
Reburning	Reduction of NO_X	Possible	Posible	High		Plant specific	For existing plants, the applicability depends on the individual plant. Space restrictions make reburning less appropriate for retrofit situations than for new ones
Measures to reduce N_2O emissions in FBC boilers							
Low excess air	Reduction of N_2O emissions	Possible	Possible	High	Higher CO emissions	Plant specific	
Increased fluidised bed temperature	Reduction of N_2O emissions	Possible	Possible	Experimental stage	Increased NO_X and SO_2 emissions	Not available	Corrosion risk
Use of catalytic material such as MgO or CaO in the boiler	Reduction of N_2O emissions	Possible	Possible	Experimental stage		Not available	
Increased flue-gas temperature	Reduction of N_2O emissions	Possible	Possible	Pilot plant stage		Not available	

Table 4.62: Techniques to consider for the prevention and control of NO_X and N_2O emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Secondary measures							
Selective Non-Catalytic Reduction (SNCR)	Reduction of NO_X, although the reduction rate is much less than with SCR	Possible	Possible	High	Ammonia slip	Plant specific	Very small temperature window and sensitive to load variation. For these reasons, application is very limited at PF LCPs and limited at CFBC
Selective Catalytic Reduction (SCR)	Reduction of NO_X	Possible	Possible	High	Ammonia slip	Plant specific	Until now, the SCR technique has only been applied on hard coal-fired plants
Selective auto-catalytic reduction (SACR)							New technique for NO_X reduction, already under full-scale demonstration
Combined techniques	Reduction of NO_X and SO_2	Possible, but rarely applied in new plants	Possible, but rarely applied	Very limited	Depends on the individual process	Not available	The combined techniques covers only a small market share compared to SCR techniques

Table 4.63: Techniques to consider for the prevention and control of NO_X and N_2O emissions

4.4.7 Techniques for the prevention and control of water pollution

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Wet FGD							
Water treatment by flocculation, sedimentation, and neutralisation	Removal of fluoride, heavy metal, COD and particulates	Possible	Possible	High	Adding of sludge to coal to be redistributed to fly ash and FGD gypsum, or re-use as a filling material in the mining industry	Plant specific	Adding sludge to coal and internally re-used in the FGD has to be assessed on a case-by-case basis
Ammonia reduction by air stripping, precipitation or biodegradation	Reduced ammonia content	Only applicable if ammonia content in waste water is high because of the SCR/SNCR		High		Plant specific	
Closed loop operation	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Mixing of waste water with coal ash	Avoiding waste water discharge	Possible	Possible	High	Stabilised material can be used as filling material in open cast mines	Plant specific	
Slag flushing and transport							
Closed water circuit by filtration or sedimentation	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Regeneration of demineralisers and condensate polishers							
Neutralisation and sedimentation	Reduced waste water discharge	Possible	Possible	High	Sludge that needs to be dewatered to be disposed of	Plant specific	
Elutriation							
Neutralisation		Only in case of alkaline operation		High		Plant specific	
Washing of boilers, air preheater and precipitator							
Neutralisation and closed loop operation, or dry cleaning methods	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Surface run-off							
Sedimentations or chemical treatment and internal re-use	Reduced waste water discharge	Possible	Possible	High		Plant specific	

Table 4.64: Techniques to consider for the prevention and control of water pollution

4.5 Best available techniques (BAT) for the combustion of coal and lignite

4.5.1 Introduction

In understanding this section and its contents, the attention of the reader is drawn back to the preface of this document and in particular the fifth section of the preface: ‘How to understand and use this document’. The techniques and associated emission and/or consumption levels, or ranges of levels, presented in this section have been assessed through an iterative process involving the following steps:

- identification of the key environmental issues for the sector; which are emissions to air and water, thermal efficiency and combustion residues
- examination of the techniques most relevant to address those key issues
- identification of the best environmental performance levels, on the basis of the available data in the European Union and worldwide
- examination of the conditions under which these performance levels were achieved; such as costs, cross-media effects, main driving forces involved in the implementation of this techniques
- selection of the best available techniques (BAT) and the associated emission and/or consumption levels for this sector in a general sense all according to Article 2(11) and Annex IV of the Directive.

Expert judgement by the European IPPC Bureau and the relevant Technical Working Group (TWG) has played a key role in each of these steps and in the way in which the information is presented here.

On the basis of this assessment, techniques, and as far as possible emission and consumption levels associated with the use of BAT, are presented in this section that are considered to be appropriate to the sector as a whole and in many cases reflect current performance of some installations within the sector. Where emission or consumption levels ‘associated with best available techniques’ are presented, this is to be understood as meaning that those levels represent the environmental performance that could be anticipated as a result of the application, in this sector, of the techniques described, bearing in mind the balance of costs and advantages inherent within the definition of BAT. However, they are neither emission nor consumption limit values and should not be understood as such. In some cases, it may be technically possible to achieve better emission or consumption levels but due to the costs involved or cross-media considerations, they are not considered to be appropriate as BAT for the sector as a whole. However, such levels may be considered to be justified in more specific cases where there are special driving forces.

The emission and consumption levels associated with the use of BAT have to be seen together with any specified reference conditions (e.g. averaging periods).

The concept of ‘levels associated with BAT’ described above is to be distinguished from the term ‘achievable level’ used elsewhere in this document. Where a level is described as ‘achievable’ using a particular technique or combination of techniques, this should be understood to mean that the level may be expected to be achieved over a substantial period of time in a well maintained and operated installation or process using those techniques.

Where available, data concerning costs have been given together with the description of the techniques presented in the previous sections. These give a rough indication about the magnitude of costs involved. However, the actual cost of applying a technique will depend strongly on the specific situation regarding, for example, taxes, fees, and the technical characteristics of the installation concerned. It is not possible to evaluate such site-specific factors fully in this document. In the absence of data concerning costs, conclusions on economic viability of techniques are drawn from observations on existing installations.

It is intended that the general BAT in this section are a reference point against which to judge the current performance of an existing installation or to judge a proposal for a new installation. In this way they will assist in the determination of appropriate ‘BAT-based’ conditions for the installation or in the establishment of general binding rules under Article 9(8). It is foreseen that new installations can be designed to perform at, or even better than, the general BAT levels presented here. It is also considered that existing installations could move towards the general BAT levels or do better, subject to the technical and economic applicability of the techniques in each case.

While the BREFs do not set legally binding standards, they are meant to give information for the guidance of industry, Member States and the public on achievable emission and consumption levels when using specified techniques. The appropriate limit values for any specific case will need to be determined taking into account the objectives of the IPPC Directive and the local considerations.

To avoid duplication throughout this document, refer to BAT on Environmental Management System (EMS) in Section 3.15.1.

4.5.2 Unloading, storage and handling of fuel and additives

The BAT for preventing releases from the unloading, storage and handling of coal, and lignite, and also for additives such as lime, limestone, ammonia, etc. are summarised in Table 4.65.

Material	Pollutant	BAT
Coal and lignite	Dust	• the use of loading and unloading equipment that minimises the height of fuel drop to the stockpile, to reduce the generation of fugitive dust • in countries where freezing does not occur, using water spray systems to reduce the formation of fugitive dust from coal stockpiles • according to the generation of fugitive emissions, covering stockpiles of petroleum coke • grassing over long-term storage areas of coal to prevent fugitive emission of dust and fuel loss caused by oxidation in contact with the oxygen of air • applying the direct transfer of lignite via belt conveyors or trains from the mine to the on-site lignite storage area • placing transfer conveyors in safe, open areas aboveground so that damage from vehicles and other equipment can be prevented. • using cleaning devices for conveyor belts to minimise the generation of fugitive dust • using enclosed conveyors with well designed, robust extraction and filtration equipment on conveyor transfer points to prevent the emission of dust • rationalising transport systems to minimise the generation and transport of dust within the site • the use of good design and construction practices and adequate maintenance.
	Water contamination	• having storage on sealed surfaces with drainage, drain collection and water treatment for settling out • collecting surface run-off (rainwater) from coal and lignite storage areas that washes fuel particles away and treating this collected stream (settling out) before discharge.
	Fire prevention	• surveying storage areas for coal and lignite with automatic systems, to detect fires, caused by self-ignition and to identify risk points.
Lime and limestone	Dust	• having enclosed conveyors, pneumatic transfer systems and silos with well designed, robust extraction and filtration equipment on delivery and conveyor transfer points to prevent the emission of dust.
Pure liquified ammonia	Health and safety risk according to ammonia	• for handling and storage of pure liquified ammonia: pressure reservoirs for pure liquified ammonia >100 m^3 should be constructed as double wall and should be located subterraneously; reservoirs of 100 m^3 and smaller should be manufactured including annealling processes • from a safety point of view, the use of an ammonia-water solution is less risky than the storage and handling of pure liquefied ammonia.

Table 4.65: BAT for the unloading, storage, and handling of coal, lignite and additives

4.5.3 Fuel pretreatment

For the fuel pretreatment of coal and lignite, blending and mixing of fuel are considered to be part of BAT, in order to ensure stable combustion conditions and to thus reduce peak emissions. Switching fuel, for example from one coal to another coal with a better environmental profile, can also be regarded as BAT.

4.5.4 Combustion

For the combustion of coal and lignite, pulverised combustion (PC), fluidised bed combustion (CFBC and BFBC) as well as pressurised fluidised bed combustion (PFBC) and grate firing are all considered to be BAT for new and existing plants. Grate firing should preferably only be applied to new plants with a rated thermal input below 100 MW.

For the design of new boilers or retrofit projects for existing plants, those firing systems are BAT which assure a high boiler efficiency and which include primary measures to reduce the generation of NO_X emissions, such as air and fuel staging, advanced low-NO_X burners and/or reburning, etc. The use of advanced computerised control system in order to achieve a high boiler performance with increased combustion conditions that support the reduction of emissions are also considered as BAT.

4.5.5 Thermal efficiency

For the reduction of greenhouse gases, in particular releases of CO_2 from coal- and lignite-fired combustion plants, the best available options from today's point of view are techniques and operational measures to increase thermal efficiency. Secondary measures of CO_2 capture and disposal, as described in Annex 10.2 of this document, are at an early stage of development. These techniques might be available in the future, but they cannot yet be considered as BAT.

For power plants, energy efficiency is considered as the heat rate (fuel input energy/energy output at power plant border) and as the power plant efficiency, which is here considered as the inverse of heat rate, i.e. the percentage of energy produced/fuel input energy. The fuel energy is measured as the lower heating value. By applying ultra supercritical steam parameters to improve the efficiency, such as double reheat, and the most advanced high temperature materials, coal- and lignite-fired condensing power plants with a heat rate of 2.08 (48 %) have been built using direct water cooling.

Because extremely efficient condensing power plants tend to be so expensive to build they are considered to be economically not competitive. Therefore, the heat rate and the efficiency level associated with the use of BAT for new coal- or lignite-fired condensing power plants (pulverised coal or lignite combustion in DBB or WBB boilers) with direct water cooling (with a capacity of over 300 MW_{th}) is considered to be 2.3 – 2.2 (43 – 47 %), using supercritical steam parameters. Increasing steam parameters (supercritical steam) is another means to increase efficiency when CHP is not possible.

Highest efficiencies are only achieved with extremely high steam parameters used in base load plants.Peak load plants with frequent start-up cycles have to be designed with lower steam parameters resulting in lower efficiencies.

CHP plants need to be one of the technically and economically most efficient means to increase the energy efficiency (fuel utilisation) of an energy supply system. Co-generation is therefore considered as the most important BAT option in order to reduce the amount of CO_2 released to the air per unit of energy generated. CHP should be a task for any new build power plant whenever economically feasible, i.e. whenever the local heat demand is high enough to warrant the construction of the more expensive co-generation plant instead of the simpler heat or electricity only plant. Because the demand of heat varies throughout the year, CHP plants needs to be very flexible concerning the ratio of produced heat to electricity and they should also possess high efficiencies for part load operation. In this context, plants containing condensing turbines with steam withdrawal are also mentioned, where efficiency of plants with condensing turbines with steam withdrawal is between co-generation and condensing plants.

The exergetic efficiency (see also Section 2.7.5) associated with the operation of a CHP plant under BAT conditions is considered to be 45 - 55 %, which is equal to a heat rate in the range of 1.3 - 1.1, and an energy (fuel) efficiency of 75 - 90 %, depending on the specific plant application. Comparing this to the heat rate and the efficiency of new coal- and lignite-fired electricity only condensing plants with efficiencies of 42 – 47 % and heat rates of 2.3, the fuel savings, and thus the reduced amount of CO_2 generated, become apparent.

It should be kept in mind that these BAT levels are not achieved under all operating conditions. The energy efficiency is at its best at the design point of the plant. The actual energy efficiencies throughout the operational period of the plants may be lower due to changes in the load during the operation, quality of the fuel, etc. The energy efficiency also depends on the cooling system of the power plant, its geographical location (see Table 2.3), and on the energy consumption of the flue-gas cleaning system.

For existing coal- and lignite-fired plants, a number of retrofit and repowering techniques can be applied to improve the thermal efficiency. The technical measures described in Section 3.2.6.1 should be taken into account as part of the BAT options to improve the efficiency of existing plants. Significant results have been achieved by repowering old boilers, especially in transition phase countries.

In general, the following measures need to taken into consideration to increase efficiency:

- combustion: minimising the heat loss due to unburned gases and elements in solid wastes and residues from combustion
- the highest possible pressure and temperature of medium pressure steam. Repeated superheating of the steam to increase net electric efficiency
- the highest possible pressure drop in the low pressure end of the steam turbine through the lowest possible temperature of the cooling water (fresh water cooling)
- minimising the heat loss through the flue-gas (utilisation of residual heat or district heating)
- minimising the heat loss through the slag
- minimising the heat loss through conduction and radiation with isolation
- minimising the internal energy consumption by taking appropriate measures, e.g. scorification of the evaporator, greater efficiency of the feed-water pump, etc.
- preheating the boiler feed-water with steam
- improving blade geometry of the turbines.

The levels of the thermal efficiency associated with the application of the BAT measures that have been considered in Chapter 4.3 to improve efficiency are summarised in Table 4.66.

Fuel	**Comb. Tech.**	**Unit thermal efficiency (net) (%)**	
		New plants	**Existing plants**
Coal and lignite	Cogeneration (CHP)	75 – 90	75 – 90
Coal	PC (DBB and WBB)	43 – 47	The achievable improvement of thermal efficiency depends on the specific plant, but as an indication a level of 36[1] – 40 % or an incremental improvement of more than 3 % points can be seen as associated with the use of BAT for existing plants
	FBC	>41	
	PFBC	>42	
Lignite	PC (DBB)	42 – 45	
	FBC	>40	
	PFBC	>42	
1	Industry and one Member State claimed that for existing plants, the achieved net unit efficiencies following major upgrading projects are only in the range of 30 – 40 %. They claimed that this depends on the specific plant and the fuel characteristics as well as the climatic conditons, taking into account the efficiency drop due to the significant energy consumption of the (usually retrofitted) emissions control equipment.		

Table 4.66: Levels of thermal efficiency associated with the application of the BAT measures

4.5.6 Dust

For dedusting off-gases from coal- and lignite-fired new and existing combustion plants, BAT is considered to be the use of an electrostatic precipitator (ESP) or a fabric filter, where fabric filter archives normally emission levels well below 5 mg/Nm^3. Furthermore, the best levels of Hg control are generally achieved by emission control systems (e.g. FGD + particulate control device) that use fabric filters.

Cyclones and mechanical collectors alone are not BAT, but they can be used as a pre-cleaning stage in the flue-gas path.

The BAT conclusion for dedusting and the associated emission levels are summarised in Table 4.67. The associated dust levels take into account the need to reduce fine particulates (PM_{10} and $PM_{2.5}$) and to minimise the emission of heavy metals (particularly the emission of particulate-bound Hg), since they have the tendency to accumulate preferentially on the finer dust particulates. For combustion plants over 100 MW_{th}, especially over 300 MW_{th}, the dust levels are lower because the FGD techniques which are already a part of the BAT conclusion for desulphurisation also reduce particulate matter.

The BAT associated emission levels are based on a daily average, standard conditions and an O_2 level of 6 %, and represents a typical load situation. For peak load, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher have to be considered.

Capacity (MW$_{th}$)	**Dust-emission level (mg/Nm^3)**		**BAT to reach these levels**	**Monitoring**	**Applicability**	**Comments**
	New plants	**Existing plants**				
50 – 100	5 – 20(1)	5 – 30(2)	ESP or FF	Continuous	New and existing plants	• the reduction rate associated with the use of an ESP is considered to be 99.5 % or higher • the reduction rate associated with the use of a fabric filter is considered to be 99.95 % or higher.
100 – 300	5 – 20(3)	5 – 25(4)	ESP or FF in combination FGD (wet, sd or dsi) for PC ESP or FF for CFBC	Continuous	New and existing plants	
>300	5 – 10(5)	5 – 20(6)	ESP or FF in combination with FGD (wet) for PC	Continuous	New and existing plants	• the reduction rate associated with the use of an ESP is considered to be 99.5 % or higher • the reduction rate associated with the use of a fabric filter is considered to be 99.95 % or higher • a wet scrubber used for desulphurisation also reduces dust.
	5 – 20(5)	5 – 20(6)	ESP or FF for CFBC			

Notes:
ESP (Electrostatic precipitator) **FF** (Fabric filter) **FGD(wet)** (Wet flue-gas desulphurisation)
FGD(sds) (Flue-gas desulphurisation by using a spray dryer) **FGD(dsi)** (Flue-gas desulphurisation by dry sorbent injection)
For very high dust concentrations in the raw gas, which might be the case when low calorific lignite is used as a fuel, the reduction rate of 99.95 % for the ESP or 99.99 % for fabric filters is considered to be the BAT associated level, rather than the dust concentration levels mentioned in this table.

1	Industry and one MS proposed 10 – 50 mg/Nm^3
2	Industry and one MS proposed 20 – 100 mg/Nm^3
3	Industry and one MS proposed 10 – 30 mg/Nm^3
4	Industry and one MS proposed 10 – 100 mg/Nm^3 for ESP or FF, and 10 – 50 mg/Nm^3 in the case of combination with wet FGD
5	Industry and one MS proposed for 10 – 30 mg/Nm^3
6	Industry and one MS proposed for 10 – 100 mg/Nm^3 for ESP or FF, and 10 – 50 mg/Nm^3 in the case of combination with wet FGD The rationale given by Industry proposing for the values given above, is that issues such as fuel characteristics, ash resistivity, the flue-gas inlet SO$_2$ concentration which determines the necessity for an FGD, economics, as well as high net unit efficiency requirements have not been fully taken into account. One Member State supported the Industry view and maintained that even with high efficiency ESPs, the dust emission levels achieved, when using low quality lignite with high ash resistivity and high ash content, will never reach values lower than the proposed levels for existing plants that do not need wet FGD, due to natural desulphurisation.
1, 2	One Industry representative mentioned that for coal fired plants between 50 and 100 MW, dust emissions of less than 30 mg/Nm^3 are too optimistic and gives no margin for plant deterioration in service (especially FF) or collection variability (especially ESPs). A still very stringent, but more practically attainable dust emission limit is 50 mg/Nm^3.
5,6	One Member State proposed that the BAT level should be 10 – 50 mg/Nm^3, because these levels comply with the Member States emission limits. Their abatement systems have been installed to comply with these limits. As far as new power plants are concerned, the Member State in question has a programme on coal firing plants, where a dust emission level of 20 mg/Nm^3 is foreseen.

Table 4.67: BAT for dedusting off-gases from coal- and lignite-fired combustion plants

4.5.7 Heavy metals

The mineral content of the fuel includes different substances depending on its origin. All solid fuels such as coal and lignite have a certain concentration of trace elements, such as heavy metals. The behaviour of heavy metals in the combustion process involves complex physico-chemical processes. Basically most of the heavy metals evaporate in the combustion process and condensate later in the process onto the surfaces of the particulate matter (i.e. fly ash). Most metals have sufficiently low vapour pressures at the operating temperatures that exist at typical air pollution control devices that condensation onto particulate matter is possible. Therefore, BAT to reduce the emissions of heavy metals from flue-gases of coal- and lignite-fired combustion plants is to use a high performance ESP (reduction rate >99.5 %) or a fabric filter (reduction rate >99.95 %).

Mercury has a high vapour pressure at the typical control device operating temperatures, and its collection by particulate matter control devices is highly variable. Taking into account that spray dryer FGD scrubbers and wet lime/limestone scrubbers are regarded as BAT for the reduction of SO_2 for larger combustion plants, low Hg emission levels are achieved.

For the reduction and limitation of Hg emissions, it can be stated, that coals of good quality have comparably low Hg contents and that the best levels of control are generally obtained by emission control systems that use FFs and ESPs, where high efficiency ESPs show good removal of Hg (bituminous coal) at temperatures of less than 130 ºC. In addition, some combinations of flue-gas cleaning systems can remove oxidised and particle bound Hg to some extent. For FFs or ESPs operated in combination with FGD techniques, such as wet limestone scrubbers, spray dryer scrubbers or dry sorbent injection, an average removal rate of 75 % (50 % in ESP and 50 % in FGD) or 90 % in the additional presence of SCR can be obtained. The reduction rate when firing sub-bituminous coal or lignite is considerably lower and ranges from 30 – 70 %. The lower levels of Hg capture in plants firing sub-bituminous coal and lignite are attributed to the low fly ash carbon content and the higher relative amounts of gaseous Hg in the flue-gas from the combustion of these fuels.

Periodic monitoring of Hg is BAT. A frequency of every year up to every third year, depending on the coal used, is recommended. Total Hg emissions need to be monitored and not only Hg present as part of the particle matter.

4.5.8 SO_2 emissions

In general, for coal- and lignite-fired combustion plants desulphurisation (FGD) and the use of low sulphur fuel are considered to be BAT. However, the use of low sulphur fuel can be a supplementary technique (particularly for plants over 100 MW_{th}), but generally is not itself sufficient to reduce SO_2 emissions.

A distinction of BAT has been made according to the boiler technology: large pulverised coal- and lignite-fired plants are considered separately from fluidised bed boilers, because of the different technical options for desulphurisation.

Besides the use of low sulphur coal, the techniques that are considered to be BAT for pulverised coal- and lignite-fired combustion plants are: wet scrubbers, spray dry scrubbers, and for smaller applications below approximately 250 MW_{th} also dry sorbent injection (i.e. dry FGD with an adjacent fabric filter). These techniques have a market share of more than 90 % of the flue-gas desulphurisation techniques. The corresponding rate of desulphurisation is considered for wet scrubbers between 85 and 98 %, for spray dryer scrubbers between 80 and 92 % and for dry sorbent injection between 70 and 90 %. It is, however, not necessary to run the desulphurisation plants on these levels, if the SO_2 emission achievable in this way would be far below the emission levels associated with BAT.

The wet scrubber has also a high reduction rate for HF and HCl (98 – 99 %). The associated emission level for both pollutants by using a wet scrubber is 1 – 5 mg/Nm^3. FGDs equipped with rotating gas-gas heat exchangers show higher emissions. Especially for HF, the overall removal efficiency is lower than for SO_2 and HCl.

Another advantage of the wet scrubber is its contribution to the reduction of dust and heavy metal (such as Hg) emissions. Existing plants that have already applied a wet FGD system can reduce the SO_2 emissions by optimising the flow pattern in the absorber vessel. The wet scrubbing process is expensive for smaller plants and has therefore not been considered as BAT for plants with a capacity of less than 100 MW_{th}. However, on the contrary to other FGD systems, wet scrubbers produce gypsum which may be a saleable product used by the cement or construction industries.

The seawater scrubber has been considered to be part of the BAT conclusion because of its high reliability, and because it is a simple process which does not require slurry handling and does not generate by-products. However, local conditions such as seawater conditions, tidal flows, the marine (aquatic) environment close to the scrubber water outlet, etc. need to be carefully examined in order to avoid any negative environmental or ecological effects. Effects may arise from the reduction of the pH level in the general vicinity of the power plant as well as from the input of remaining metals (heavy metals in particular Hg) and fly ash. This is especially applicable for plants situated in an estuary.

Regarding Hg, care needs to be taken that Council Directive 84/156/EEC on mercury discharges is complied with. Under that Directive and in absence of Community limit values, the Member States will fix emission standards for mercury discharges autonomously in accordance with the previous Directive 76/464/EEC. Such standards must take into account the best technical means available and must not be less stringent than the most nearly comparable limit value in Annex I of Directive 84/156/EEC. Furthermore, this requires a monitoring procedure.

For combustion plants less than 100 $MW_{th,}$ the use of low sulphur coal or sorbent injection is considered to be BAT.

Other techniques for desulphurisation described in Section 3.5, such as combined techniques for the reduction of NO_X and $SO_{2,}$ like the activated carbon and the DESONOX process, may qualify as BAT in cases where site-specific conditions allow these technique to be used or justify the investment.

The effect of natural desulphurisation according to the use of low quality lignites with a low sulphur and a high alkaline ash content may also achieve SO_2 removal as high as 90 %, but will lead, because of the low quality of the fuel, to high dust emissions and higher amounts of residues.

The burning temperature in FBC is favourable for sulphur to react with the calcium or magnesium compounds added into the bed. The reaction products, gypsum and unreacted limestone are removed, partly from the bed together with bed ash, and partly from the electrostatic precipitator or baghouse together with the fly ash. Higher Ca/S ratios are needed in fluidised bed combustion (FBC) than in wet scrubbing or spray towers for a high reduction of sulphur. However, even with very high Ca/S ratios, FBC combustion cannot achieve such high reduction rates as from wet scrubbing.

Higher degrees of desulphurisation are achieved in circulating fluidised bed combustion (CFBC) boilers than in bubbling fluidised bed combustion (BFBC) boilers. For coal and lignite, removal efficiencies as high as 80 – 95 % are possible in CFBCs with moderate Ca/S ratios (i.e. between 2 – 4). When the fuel sulphur contents increase, Ca/S decreases slightly for a certain sulphur removal (e.g. 90 % removal). However, the actual mass flowrate of limestone needed increases as well as the amount of residues generated. Hence, the current trend for CFBCs firing high sulphur (4 – 6 % S) fuels is to combine: a) *in situ* sulphur capture by limestone in the furnace and b) cold-end sulphur capture. When all aspects are taken into consideration, sulphur capture in CFBCs with only limestone injection in the bed is considered as BAT for low or moderate sulphur (<1 – 3 % S) fuels.

In BFBCs, the corresponding removal efficiency is between 55 – 65 % with a similar quality of coal or lignite and with a similar quality and consumption of limestone. Because of the low desulphurisation in BFBCs, the injection of limestone or dolomite cannot be considered as BAT. In BFBC boilers burning only coal, end-of-pipe techniques already described as BAT for pulverised coal combustion are BAT with the associated emission levels of those techniques.

The BAT conclusion for desulphurisation and the associated emission levels are summarised in Table 4.68. The BAT associated emission levels are based on a daily average, standard conditions and an O_2 level of 6 %, and represents a typical load situation. For peak load, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher have to be regarded.

Capacity (MW_{th})	Combustion technique	SO_2 emission level associated with BAT (mg/Nm^3)		BAT options to reach these levels	Applicability	Monitoring
		New plants	Existing plants			
50 – 100	Grate-firing	200 – 400	200 – 400	Low sulphur fuel or FGD (sds)	New and existing plants	Continuous
	PC	200 – 400(1)	200 – 400(2)	Low sulphur fuel FGD (sds, dsi)	New and existing plants	Continuous
	CFBC and PFBC	150 – 400(3)	150 – 400(4)	Low sulphur fuel Limestone injection	New and existing plants	Continuous
	BFBC	150 – 400(5)	150 – 400(6)	Low sulphur fuel FGD (dsi) FGD (sds)	New and existing plants	Continuous
100 – 300	PC	100 – 200	100 – 250(7)	Low sulphur fuel FGD (wet, sds) FGD (dsi, up to about 200 MW_{th}) Seawater scrubbing Combined techniques for the reduction of NO_x and SO_2	New and existing plants	Continuous
	CFBC and PFBC	100 – 200	100 – 250(8)	Low sulphur fuel Limestone injection	New and existing plants	Continuous
	BFBC	100 – 200	100 – 250(9)	Low sulphur fuel FGD (wet, sds)	New and existing plants	Continuous
>300	PC	20 – 150(10)	20 – 200(11)	Low sulphur fuel FGD (wet) FGD (sds) Seawater scrubbing Combined techniques for the reduction of NO_x and SO_2	New and existing plants	Continuous
	CFBC and PFBC	100 – 200	100 – 200(12)	Low sulphur fuel Limestone injection	New and existing plants	Continuous
	BFBC	20 – 150	20 – 200(13)	Low sulphur fuel FGD (wet)	New and existing plants	Continuous

Notes:
PC (Pulverised combustion) **BFBC** (Bubbling fluidised bed combustion)
CFBC (Circulating fluidised bed combustion) **PFBC** (Pressurised fluidised bed combustion)
FGD(wet) (Wet flue-gas desulphurisation) **FGD(sds)** (Flue-gas desulphurisation by using a spray dryer)
FGD(dsi) (Flue-gas desulphurisation by dry sorbent injection)

	Industry declared that the levels should be as follows:
1-6, 8-9, 12,13	upper level 300 mg/Nm^3
7	upper level 600 mg/Nm^3
10	upper level 200 mg/Nm^3
11	upper level 400 mg/Nm^3
	These levels are proposed by Industry because they claim that better takes into account the fuel characteristics, the inlet flue-gas SO_2 concentration affects the BAT achievable levels considering the agreed wet scrubber SO_2 removal efficiencies of 85 – 98 %, the high energy consumption of such a wet scrubber system in relation with the net unit efficiency requirements, and because an optimisation is necessary between emission control technique performance (low emission levels) and related energy consumption (energy penalty). One Member State claimed mainly the same upper levels of the ranges except for (2) which should be 2000 mg/Nm^3 and for (7) which should be 1200 mg/Nm^3. Their rationale is, that for certain existing lignite-fired power plants, burning fuel with a high sulphur content produces raw flue-gas SO_2 concentrations in the range of 15000 – 20000 mg/Nm^3 (dry and 6 % O_2 conditions). Only a sophisticated and large wet FGD system with an SO_2 removal efficiency of 98 %, can reach SO_2 emission levels of 300 – 400 mg/Nm^3, dry, at 6 % O_2. One Member State proposed that the emission levels associated to the use of BAT should be:
7, 8, 9	upper level 600 mg/Nm^3
11, 12, 13	Modify the range to 200 – 400 mg/Nm^3
	Their rationale is because these levels comply with the Member States emission limits. As far as new power plants are concerned, the Member State in question has a programme on coal firing plants, where an emission level of 200 mg/Nm^3 is foreseen.
1-6	One Industry representative mentioned that operators of small coal-fired LCPs would welcome the opportunity to meet SO_2 emission levels by consuming low sulphur coal. However, this option is not without its commercial and operational problems and, for it to even be an option at all, the SO_2 emission limit needs to be set at a minimum of 1000 mg/Nm^3.

Table 4.68: BAT for the prevention and control of sulphur dioxides from coal- and lignite-fired combustion plants

4.5.9 NO_X emissions

In general, for coal- and lignite-fired combustion plants, the reduction of nitrogen oxides (NO_X) by using a combination of primary and/or secondary measures is considered to be BAT. The nitrogen compounds of interest are nitric oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as NO_X, and nitrous oxide (N_2O). A distinction of BAT has been made according to the boiler technology, i.e. pulverised or fluidised bed combustion, and whether coal or lignite is used as a fuel.

For pulverised coal combustion plants, the reduction of NO_X emissions, by the use of primary measures in combination with secondary measures such as SCR is BAT, where the separation efficiency of the SCR system ranges between 80 and 95 %. There are different processes available today for the regeneration of used catalysts, which increases the catalyst lifetime considerably and which, therefore, reduces the operating costs. The economic feasibility of applying an SCR system to an existing boiler is primarily a question of the expected remaining lifetime of the plant, which cannot necessarily be determined by the age of the plant. The use of SCR has the disadvantage of a ‘slide’ ammonia emission (i.e. ammonia slip). With respect to the ammonia concentration when using an SCR, a level of less than 5 mg/Nm^3 is the associated BAT level. This level also avoids problems in the future utilisation of fly ash and the smell of the flue-gas in the surrounding area.

Combined techniques for the reduction of NO_X and SO_2 described in Section 3.5, such as the activated carbon and the DESONOX process, are part of the BAT conclusion, but their advantages, disadvantages and applicability need to be verified on a local level.

For pulverised lignite-fired combustion plants, the combination of different primary measures is considered as BAT. This means, for instance, the use of advanced low NO_X burners in combination with other primary measures such as flue-gas recirculation, staged combustion (air staging), reburning, etc. The SCR technique is regarded as part of BAT for the reduction of NO_x emissions, but on account of the relatively low NO_X emissions of lignite-fired plants compared with hard coal-fired plants, SCR has not been considered as BAT in a general sense for the combustion of lignite.

For the application of advanced low NO_X burners to existing boilers, it should be noted, that in older installations, the furnaces will usually have been built as small as possible (designed for high combustion intensity). Therefore, the furnace temperature can only be reduced to a limited extent. In addition, the furnace depth can only accommodate slightly longer flames than it was originally designed for. For older furnaces, the application of modern swirl burners, which have flames not much longer than those in the original burners, are regarded as BAT.

The furnace height in old furnaces is usually small and may prevent the installation of overfire air (OFA) ports. Even if there is room for an OFA, the residence time of the combustion gases in the upper part of the furnace may not be long enough for complete combustion. In boilers that were built in later years when more was known about NO_X formation, the furnace would usually be larger and lower NO_X levels can thus be achieved. The best results are obtained when low NO_X combustion is integrated into the boiler design, i.e. in new installations.

For small plants without high load variations and with a stable fuel quality, the SNCR technique can be seen as an additional measure to further reduce NO_X emissions.

The use of primary measures, either for coal or lignite, tends to cause incomplete combustion resulting in a higher level of unburned carbon in the fly ash and some carbon monoxide emissions. With a good design and control of combustion, these negative impacts can mostly be avoided. The amount of unburned carbon-in-ash varies according to the fuel and is normally somewhat higher than without primary measures. For most of the utilisation options for the fly ash, the associated BAT level of unburned carbon-in-ash is below 5 %. Levels of unburned carbon below 5 % can normally be achieved but with some coals only at the cost of somewhat higher NO_X emissions. Primary NO_X reduction measures also have an impact on the total energy efficiency of the process. If the combustion remains incomplete, the energy efficiency remains lower. A normal rise in the amount of unburned carbon due to low NO_X combustion has a negative impact of approximately 0.1 – 0.3 % on the unit efficiency.

For the fluidised bed combustion (FBC) of coal and lignite, staged combustion (air-staging) is considered to be BAT. In this case, the combustion starts in under stoichiometric conditions by pyrolysis in the bubbling bed or in the bubbling bed type lower part of the circulating bed. The rest of the combustion air is added later in stages to finally achieve the over stoichiometric conditions and to complete combustion. In circulating fluidised beds, the circulating bed material ensures an even temperature distribution that typically keeps the furnace temperature below 900 °C, which prevents, to a large extent, the formation of thermal NO_X. On the other hand, low temperatures promote the generation of N_2O and increase the amount of unburned carbon. The fluidised bed combustion option is, therefore, a balancing act between the partially conflicting requirements of NO_X, N_2O, and SO_2 control, and the control of unburned hydrocarbons, CO, and char. In FBC boilers, N_2O emission levels of 30 – 150 mg/Nm^3 may occur depending on the fuel used (hard coal or lignite).

In the bubbling bed freeboard above the bed itself, the combustion of the pyrolysis gases can produce temperatures in excess of 1200 °C and promoting this, the formation of thermal NO_X. As a general rule, NO_X formation in a properly designed fluidised bed can be kept below the NO_x formation achieved by low NO_X burners.

The BAT conclusion for the prevention and control of NO_X emissions and the associated emission levels are summarised in Table 4.69. The BAT associated emission levels are based on a daily average, standard conditions and an O_2 level of 6 %, and represent a typical load situation. For peak load, start up and shut down periods, as well as for operational problems of the flue-gas cleaning systems, short-term peak values which could be higher have to be regarded.

Capacity (MW$_{th}$)	Combustion technique	NO$_x$ emission level associated with BAT (mg/Nm^3)		Fuel	BAT options to reach these levels	Applicability	Monitoring
		New plants	Existing plants				
50 – 100	Grate firing	200 – 300	200 – 300(1)	Coal and lignite	Pm and or SNCR	New and existing plants	Continuous
	PC	90 – 300(2)	90 – 300(3)	Coal	Combination of Pm (such as air and fuel staging, low NO$_x$ burner, etc.), SNCR or SCR as an additional measure	New and existing plants	Continuous
	BFBC, CFBC and PFBC	200 – 300	200 – 300	Coal and lignite	Combination of Pm (such as air and fuel-staging)	New and existing plants	Continuous
	PC	200 – 450	200 – 450(3)	Lignite	Combination of Pm (such as air and fuel-staging)	New and existing plants	Continuous
100 – 300	PC	90(4) – 200	90 – 200(5)	Coal	Combination of Pm (such as air and fuel-staging, low NO$_x$ burner, reburning, etc), in combination with SCR or combined techniques	New and existing plants	Continuous
	PC	100 – 200	100 – 200(6)	Lignite	Combination of Pm (such as air and fuel-staging, low NO$_x$ burner, reburning, etc.)	New and existing plants	Continuous
	BFBC, CFBC and PFBC	100 – 200	100 – 200(7)	Coal and lignite	Combination of Pm (such as air and fuel-staging), if necessary, together with SNCR	New and existing plants	Continuous
>300	PC	90 – 150	90 – 200(8)	Coal	Combination of Pm (such as air and fuel-staging, low NO$_x$ burner, reburning, etc.), in combination with SCR or combined techniques	New and existing plants	Continuous
	PC	50 – 200(9)	50 – 200(10)	Lignite	Combination of Pm (such as air and fuel-staging, low NO$_x$ burner, reburning, etc)	New and existing plants	Continuous
	BFBC, CFBC and PFBC	50 – 150	50 – 200(11)	Coal and lignite	Combination of Pm (such as air and fuel-staging)	New and existing plants	Continuous

Notes:
PC (Pulverised combustion) **BFBC** (Bubbling fluidised bed combustion) **CFBC** (Circulating fluidised bed combustion) **PFBC** (Pressurised fluidised bed combustion)
Pm (Primary measures to reduce NO$_x$ **SCR** (Selective catalytic reduction of NO$_{x)}$ **SNCR** (Selective non catalytic reduction of NO$_x$)
The use of anthracite hard coal may lead to higher emission levels of NO$_X$ because of the high combustion temperatures

	Industry and one Member State proposed that the levels should be as follows:
2, 6	upper level 450 mg/Nm^3
3	upper level 500 mg/Nm^3
4	lower level 100 mg/Nm^3
5, 7	upper level 300 mg/Nm^3
9	range 100 – 200 mg/Nm^3
10	range 100 – 450 mg/Nm^3
	Industry claimed that their proposed figures better consider the issue that the application of primary measures are restricted by boiler geometry and configuration (height restrictions may not allow retrofitting of air and fuel staging). One Member State added that for existing plants burning low quality lignite, the produced NO_X emission levels are quite low, due to the combustion technique inherent primary measures for NO_X reductions (flue-gas recirculation, fuel and air staging, etc.). Further modifications for improvement of already installed primary measures are restricted by boiler geometry and configuration and are not cost effective.
	Another Member State proposed that the BAT range for existing plants should be as follows:
5-7	range to be 100 – 300 mg/Nm^3
8,10,11	lower end of the range to be 100 mg/Nm^3
	The rationale is that these levels comply with the Member State's emission limits. As far as new power plants are concerned, the Member State in question has a programme on coal firing plants, where an emission level of 150 mg/Nm^3 is foreseen.
8,10,11	Another Member State claimed that they had explored the different instruments to meet a strict target of 150 mg/Nm^3. This is possible in a cost effective way by a system of NO_x emission trading. To have maximum flexibility in the system of NO_x emission trading, the Member State explained that for the oldest combustion plants, the highest level in the range (associated with the use of BAT) should be as practicable possible, and proposed a range of 100 – 650 mg/Nm^3 for existing plants over 300 MW.
1,3	Another Industry representative proposed that an upper emission level of 400mg/Nm^3 for plants in the 50 – 100 MW range.

Table 4.69: BAT for nitrogen oxide prevention and control in coal- and lignite-fired combustion plants

4.5.10 Carbon monoxide (CO)

BAT for the minimisation of CO emissions is complete combustion, which goes along with good furnace design, the use of high performance monitoring and process control techniques, and maintenance of the combustion system. Because of the negative effect of NO_X reduction on CO, a well-optimised system to reduce emissions of NO_X will also keep the CO levels down to (30 – 50 mg/Nm^3 for pulverised combustion, and below 100 mg/Nm^3 in the case of FBC). For lignite-fired combustion plants where mainly primary measures are regarded as BAT for the reduction of NO_X emissions, the CO levels can be higher (100 – 200 mg/Nm^3).

4.5.11 Hydrogen fluoride (HF) and hydrogen chloride (HCl)

For combustion plants, the wet scrubber process (especially for plants with a capacity of over 100 MW_{th}) and the spray dryer have been considered as BAT for the reduction of SO_2. These techniques also give a high reduction rate for HF and HCl (98 – 99 %). By using the wet scrubber or a spray dryer, the associated emission level for HCl is 1 – 10 mg/Nm^3 and for HF 1 – 5 mg/Nm^3. If an FGD is not applied, for example if dry lime is added to an FBC boiler, the emission level of both HCl and HF can be much higher.

In measuring elevated levels of HF or HCl in the stack, the problem might be related to an internal flue-gas leakage in the rotating gas-gas heat-exchanger. In this event, raw flue-gas will then go directly to the stack without reducing the SO_2, HF and HCl contents. Therefore, a modern type of gas-gas heat-exchanger has been considered as part of the BAT conclusion. However, because of operational and economic reasons, replacement only needs to be considered when the heat exchanger needs to be changed or replaced anyway. The new gas-gas heat-exchanger might be a combination of a heat extractor (multi-pipe heat extractor) and a reheater, or the use of heat pipes. The best option in this case is flue-gas discharge via the cooling tower, if possible. In this case, no flue-gas reheating is necessary and therefore no gas-gas heat-exchanger is needed. Another option is the use of a high-grade drop catcher and passing the flue-gas via an acid resistant stack pipe, where no flue-gas reheating is necessary and therefore no gas-gas heat-exchanger is needed.

Because the injection of limestone for CFBC has been regarded as BAT for the reduction of SO_2 instead of the wet scrubber of pulverised combustion, the BAT associated level of HCl is between 15 – 30 mg/Nm^3.

4.5.12 Ammonia (NH_3)

The disadvantage of SNCR and SCR systems is the emission of unreacted ammonia into the air (ammonia slip). The ammonium concentration associated with the use of BAT is considered to be below 5 mg/Nm^3 to avoid problems in the utilisation of fly ash and possibly the smell of the flue-gas in surrounding areas. The ammonium slip is often the limiting factor in the utilisation of the SNCR technique. To avoid ammonia slip with the SNCR technique, a low layer of SCR catalyst can be installed in the economiser area of the boiler. As this catalyst reduces the ammonia slip, it also reduces the corresponding amount of NO_X.

4.5.13 Water pollution

Different waste water streams (see Chapter 1) are generated by operating coal- and lignite-fired combustion plants. To reduce emissions to water and to avoid water contamination all measures that have been presented in Section 3.10 are considered to be BAT and summarised in the following table:

Technique	Main environmental benefit	Applicability	
		New plants	Existing plants
Wet FGD			
Water treatment by flocculation, sedimentation, filtration, ion-exchange and neutralisation	Removal of fluoride, heavy metals, COD and particulates	BAT	BAT
Ammonia reduction by air stripping, precipitation or biodegradation	Reduced ammonia content	BAT only if the ammonia content in waste water is high because of a SCR/SNCR used upstream of a FGD	
Closed loop operation	Reduced waste water discharge	BAT	BAT
Mixing of waste water with coal ash	An avoided waste water discharge	BAT	BAT
Slag flushing and transport			
Closed water circuit by filtration or sedimentation	Reduced waste water discharge	BAT	BAT
Regeneration of demineralisers and condensate polishers			
Neutralisation and sedimentation	Reduced waste water discharge	BAT	BAT
Elutriation			
Neutralisation		BAT only with alkaline operation	
Washing of boilers, air preheaters and precipitators			
Neutralisation and closed loop operation, or replacement by dry cleaning methods	Reduced waste water discharge	BAT	BAT
Surface run-off			
Sedimentations or chemical treatment and internal re-use	Reduced waste water discharge	BAT	BAT

Table 4.70: BAT for waste water treatment

As mentioned in Section 4.5.2, the storage of coal and lignite on sealed surfaces with drainage and drain collection has been considered as BAT. Any surface run-off (rainwater) of the storage areas that washes fuel particles away should be collected and treated (settling out) before being discharged. The associated BAT emission level in the discharged water is considered to be less than 30 mg/l.

Small amounts of oil contaminated (washing) water cannot be prevented from occurring occasionally at a power plant. Oil separation wells are, in general, sufficient to avoid any environmental damage.

The BAT conclusion for the wet scrubbing desulphurisation is related to the application of a waste water treatment plant. The waste water treatment plant consists of different chemical treatments to remove heavy metals and to decrease the amount of solid matter from entering the water. The treatment plant includes an adjustment of the pH, the precipitation of heavy metals and removal of the solid matter and the precipitate from the waste water. With modern technology the following parameters are monitored (where not all of these components are required to be monitored on a continuous basis): pH, conductivity, temperature, solid content, chlorine content, heavy metal concentrations (such as As, Cd, Cr, Cu, Hg, Ni, Pb, V, Zn,), fluorine concentration and chemical oxygen demand (COD). The waste water from a wet FGD treated by filtration and neutralisation still has a content of COD that needs further treatment. The quality of the waste water after the waste water treatment plant varies greatly depending on the fuel quality, desulphurisation process used and to the discharge of the waste water. Nevertheless, emission levels associated with the use of a BAT waste water treatment plant are summarised in Table 4.71

Emissions to water from a wet FGD waste water treatment plant (mg/l)	
Solids	5 – 30
COD	<150
Nitrogen compounds	<50
Sulphate	1000 – 2000
Sulphite	0.5 – 20
Sulphide	<0.2
Fluoride	1 – 30
Cd	<0.05
Cr	<0.5
Cu	<0.5
Hg	0.01 – 0.02
Ni	<0.5
Pb	<0.1
Zn	<1

Table 4.71: Emission levels associated with the use of a BAT- FGD waste water treatment plant given as a representative 24 hour composite sample

The other techniques described for waste water treatment in Chapter 3 can, in general, also be considered as BAT for this sector.

4.5.14 Combustion residues

As mentioned in Section 4.3.6, a lot of attention has already been paid by industry to the utilisation of combustion residues and by-products, instead of just depositing them in landfills. Utilisation and re-use is, therefore, the best available option and is a priority. A large number of different options to re-use residues and by-products from coal and lignite-fired combustion plants are presented in Table 4.2.

There are tens of different utilisation possibilities for different by-products. Each different utilisation option has different specific criteria for the quality of ash it needs. It is impossible to cover all of these criteria in this BAT reference document. The quality criteria are usually connected to the structural properties of the ash and the content of any harmful substances, such as the amount of unburned coal in the ash, the solubility of heavy metals, etc.

The carbon rich ash can be recovered from ash streams. This produces a carbon rich ash that can be recycled to the boiler to recover the energy in the carbon and a lower carbon ash stream that is less restricted in terms of options for beneficial re-use.

The end-product of the wet scrubbing technique is gypsum, which is a commercial product for the plant. It can be sold and used instead of natural gypsum. FGD sludges can be integrated in an FGD process by-product (gypsum) in the limits allowed. The sludges can be re-injected into the furnace when FGD and SCR techniques are applied. Practically most of the gypsum produced in power plants is utilised in the plasterboard industry. The purity of gypsum limits the amount of limestone that can be fed into the process.

The end-product of semi-dry desulphurisation processes is used in different construction purposes instead of natural minerals, such as in road construction, for earthworks of composting and storage fields, for the filling of mine pits, and for excavation dams in watertight construction.

4.6 Emerging techniques for the combustion of coal and lignite

4.6.1 Pilot plant for a pre-dryer of lignite with low temperature heat

The technology of pre-drying lignite is expected to lead to an increase in the efficiency of lignite plants of about 4 to 5 percentage points, in theory. The aim of the technique is to dry the lignite, which arrives wet directly from the open cast mine, with low temperature heat of about 120 to 150 °C instead of hot flue-gas at 1000 °C. Furthermore, the aim is that the energy required to evaporate the water content of the lignite will be regained by condensing the vapour. Two different processes for this are available:

One, mechanical-thermal dewatering is currently under development. The pilot plant for this process produces 12 t/h of dry lignite at a water content of approximately 22 %. The lignite is heated up and squeezed at 60 bar and 200 °C in order to separate the water. At the end, the hackled lignite is reheated again.

The second process for drying the lignite is already in a later stage of development. It involves drying the lignite in a fluidised bed apparatus with internal utilisation of the waste heat. The steam dissipating from the dryer is separated from its contents of lignite particles by an electrostatic precipitator. Afterwards, it is compacted again by a compressor which works in an open heat pump process, and is finally condensed inside the pipe coils, which are used as heating surfaces in the dryer. The condensation heat is thereby transmitted into the fluidised bed to dry the lignite. Part of the dedusted steam is used to fluidise the lignite, and is fed into the apparatus by a ventilator. A pilot plant of this technology produces 90 t/h of dry lignite at a water content of 12 %. Both processes are shown in the following figure.

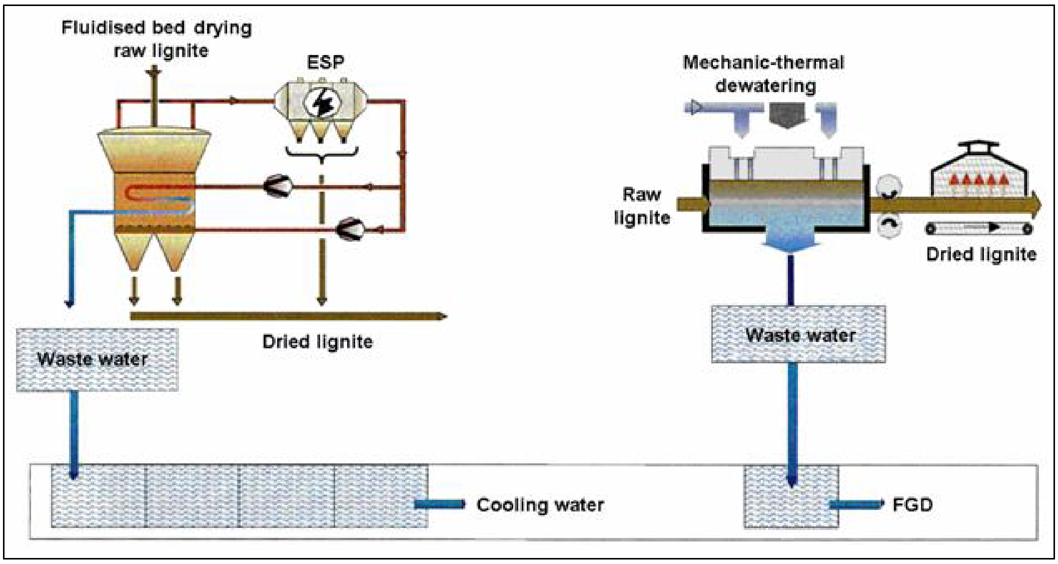


Figure 4.50: Pilot plant for lignite dying
[137, Elsen, et al., 2001]

4.6.2 Simultaneous control of SO_X, NO_X and mercury

The flue-gas treatment system simultaneously captures sulphur and nitrogen oxides, heavy metals, such as mercury, from the burning of fossil fuels. This system is a post-combustion emission control system with higher capture rates of more pollutants while producing saleable co-products. It is under demonstration in the US [189, Caldwell, 2001].

Description of the process

The system is a gas-phase oxidation process to simultaneously capture up to 99 % of the nitrogen and sulphur oxides as well as basic vapours and heavy metals (100 % of mercury). Capture rates of up 99 % SO_x and 98 % NO_X were demonstrated at laboratory level over a wide range of temperatures found in flue-gases. Engineering cost estimates for the construction of a full scale 500 MW power plant installation is 30 – 50 % lower in capital costs and with 1/6th operating costs compared to limestone/SCR. The main applications are where fossil fuels, such as coal and natural gas, are burned for the generation of electrical power. Other applications are found with smelters, municipal incinerators, industrial boilers.

Advantages of the system

- high simultaneous SO_x and NO_X capture rates to 99 %
- heavy metals such as mercury and other metallic species will be captured
- produces saleable co-products
- does not use limestone/lime
- does not contribute to CO_2 emissions
- does not use catalysts to produce hazardous waste
- the reagent is recycled
- uses proven co-product technologies
- it can be retrofitted on most plants
- projected lower capital costs and lower operating costs than conventional technologies.

5 COMBUSTION TECHNIQUES FOR BIOMASS AND PEAT

5.1 Applied processes and techniques

5.1.1 Unloading, storage and handling of biomass and peat

The approach to fuel transportation, unloading, storing, and the handling of biomass and peat is different from that of coal for several reasons. Peat in particular is reactive and can self-ignite or decompose if kept in storage for a long time. Typically only a few days consumption of peat is actually stored at the power plant site. Peat is usually stored, even for periods of years, in stockpiles in the production area.

5.1.1.1 Transport and handling of biomass and peat

Peat and wood fuel is transported by articulated lorries, trailers, rail or, for even shorter distances, by tractor-trailers. Peat has many characteristics which put special demands on the handling and transporting equipment. These include:

- relatively low calorific value
- low density
- tendency to freeze (due to the high moisture content)
- risk of spontaneous combustion
- bridging
- dust-raising propensity
- often considerable contamination with wood and stones.

The impact of peat transportation depends on the method of transport and the distance. The environmental impact from rail transportation is of minor importance, as only some noise will be generated. Road transportation causes noise and results in vehicle emissions. Life cycle analyses carried out, however, show that the emissions from peat production and transportation are of minor importance compared to the emissions from combustion.

At the fuel receiving station of the power plant, peat is usually unloaded to the screens, where it is either mixed with other fuels such as biomass or fed directly to the boiler house. Any large stones or pieces of wood must be screened out from the peat. After unloading at the power plant, peat and wood pass through screens and shredders to the storage. The screened wood can be added back to the fuel after it has been crushed. A typical fuel handling system (co-combustion of peat, wood and coal) is presented in Figure 5.1.

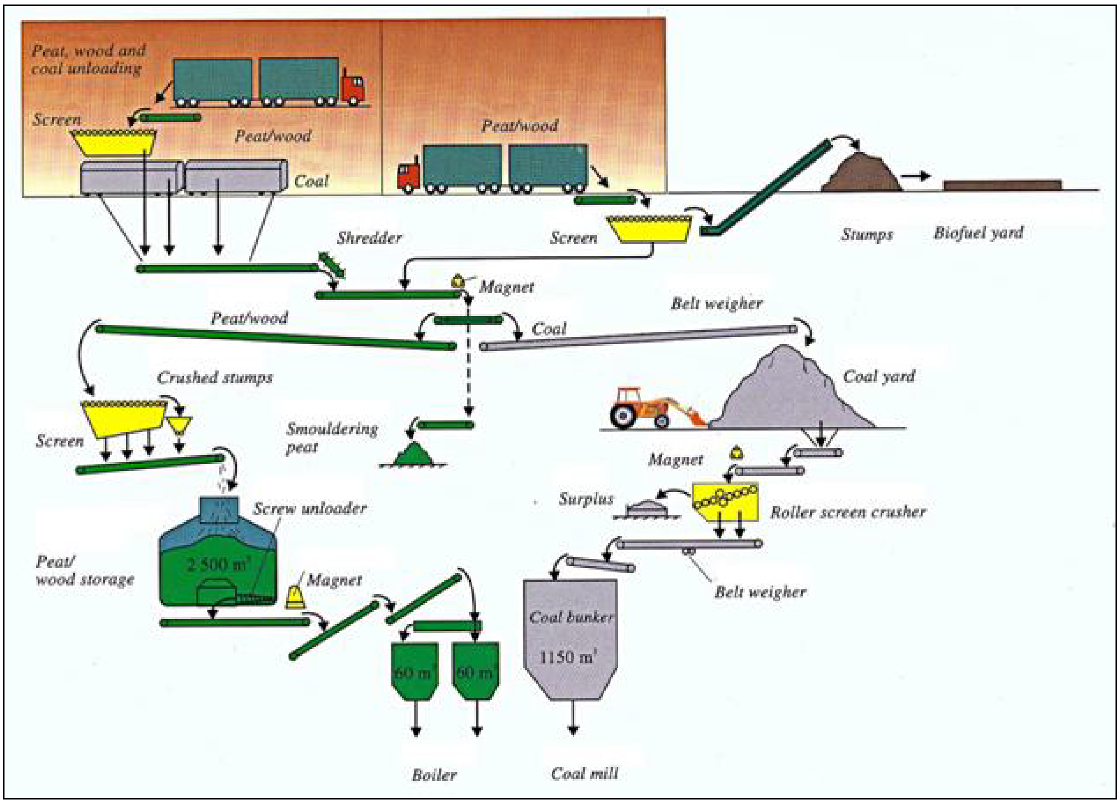


Figure 5.1: Peat, wood and coal handling system
[58, Eurelectric, 2001]

Closed silos and storage areas with dedusting devices are necessary when storing fine dusty biomass. Chips and bark are stored for longer periods in open stockpiles, with covered storage reserved for the screened and crushed fuel that is to be used for daily use.

Fuel is normally transferred from the stockpile/silos to the boiler using belt conveyors. Dust generated during peat unloading and handling can cause local harm in the plant area. Closed conveyors can be used to reduce the impact of any dusty material.

A major hazard of peat-fired power plants is the risk of fire and explosion. Dry peat ignites very easily even before it reaches the boiler; either on the peat conveyors, or even in the articulated lorry transporting the peat. It is, therefore, a general safety rule that the moisture content of peat must be at least 40 % during transport to the plant. This eliminates the raising of fugitive dust out of the fuel and reduces the speeding of fire in cases of self-ignition.

5.1.1.2 Transport and handling of straw

The approach to the transportation, unloading and storing of straw is different from that of coal, biomass and peat. The handling of straw for large CHP plants is almost solely based on bales, each weighing approximately 400 – 700 kg. Trucks carrying 20 or 24 bales transport the bales from the fields or farmers' storage area to the plant. The trucks are unloaded by a specialised overhead crane, whilst simultaneously performing a quality check (weight and moisture) of the straw. The data from the quality checks are stored on a central logistics computer. The straw batches (10 or 12 bales per batch) are either transferred to a vacant position in the straw storage area or they are transferred directly to the processing equipment. The storage is mostly fully automated and designed to hold about 2 – 3 days full load capacity of the boiler.

5.1.2 Pretreatment of biomass and peat

The moisture content of peat and wood fuel is high. The drying of biomass and peat can be done safely with regard to the fuel feeding system so no storage of dried fuel is needed. Steam dryers are safe and have low environmental impacts. They offer advantages when connected to the steam cycle, particularly in CHP production, where the drying energy can be fully regenerated to heating. However, despite the efficiency benefits, regenerative fuel drying systems have seldom proved economically attractive.

Another method used to be based on drying with flue-gas, which was subsequently fed to the stack. One problem, however, was the possible generation of organic emissions, such as wax and aromatic compounds. These can create problems, as wax sticks to the flue-gas channels and creates a potential fire risk in the electrostatic precipitator, and aromatic compounds smell and can lead to an odour nuisance to neighbours.

In several cases, presses are used to remove the moisture from bark fuels to reach a higher efficiency of the plant. However, unless the press is maintained and operated properly to reduce moisture levels to below 50 % or so, then the detriment of these pretreatment techniques (high BOD releases to water and high energy use and maintenance) offset the gains in combustion efficiency that can be expected from the pretreatment.

The straw bales are transported from the storage area by a crane and tier conveyors, and are shredded before being fed into the boiler furnace.

It is beneficial to keep straw on the fields about a month or so after harvesting, because rainfall decreases the amount of water-soluble alkalis in the straw ash. These alkalis are harmful to the combustion conditions as they lower the ash-melting temperature, which then increases the sintering risk of the fluidised bed and fouls the boiler. The amount of water-soluble alkalis present greatly influences the corrosion rate of the superheaters. Rain also recycles water-soluble alkalis back to the soil for the growth of the new crops. Apart from the natural drying of straw on the fields, no other drying of straw is relevant.

5.1.3 Special aspects in combustion and gasification of biomass and peat

5.1.3.1 Grate firing

Grate firing is the oldest firing principle used in boilers. It was the most popular firing system in small boilers until the beginning of the 1980s, when fluidised bed combustion started to become more popular, largely replacing grate firing. Today, most new solid fuel-fired boilers with a fuel input of over 5 MW are fluidised bed boilers. However, grate firing in this size range is somewhat more popular in some countries (e.g. Sweden, Denmark) and with some special fuels (e.g. wood pellets, straw, plywood and chipboard waste, and domestic waste). Today, grates and stokers are used only infrequently at large combustion plants with a fuel input in excess of 50 MW.

The combustion process in grate firing is not as well controlled as it is in pulverised fuel burners or in fluidised beds. The combustion chemistry and the temperature can vary even for the same kind of fuel particles, depending on their location on the grate. On a grate, all fuels will first be dried then pyrolysed and, finally, the char is burned on the grate. The pyrolysing share of fuel energy can be about 80 % with biofuels. Modern grate firing control guarantees an optimal burning air supply and, therefore, a low content of unburned components in the exhaust gases.

The typical operating principle in the grate firing of coal differs from biofuels. Sloped grates are typically used for biofuels. They can be static or mechanically activated. If travelling grates are used, a homogeneous layer is fed on to it. As an alternative, the fuel can also be fed onto the grate by a so-called spreader located on the furnace wall (**spreader-stoker system**). The spreader throws the fuel on the grate against the direction of the grate movement. Thus the longest burning time can be achieved for the largest particles, because they are thrown over a longer distance close to the entry of the travelling grate.

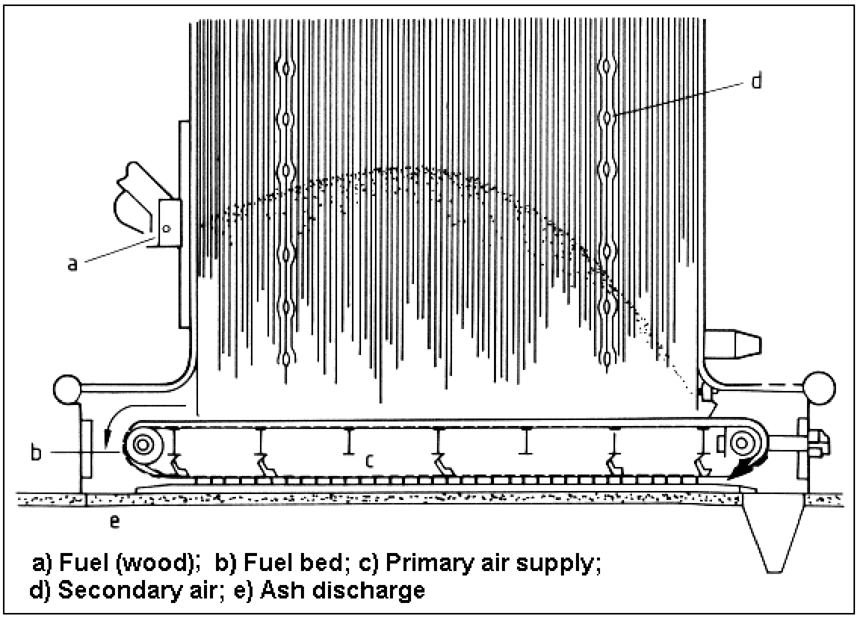


Figure 5.2: Spreader-stoker grate firing for solid fuels
[79, Bell and Chiu, 2000]

5.1.3.2 Combustion for straw

For the co-firing of straw with coal, a number of conversion technologies are possible, but if straw is utilised as the only fuel, the grate firing technology is the most commonly used solution. This is mainly due to the slagging/sintering tendency of straw. By taking some special precautions, such as the use of special bed material or additives, FBC plants have also been used for straw firing.

Normally a vibrating water-cooled grate is used, and the steam temperatures have to be kept below approximately 500 °C to keep corrosion within acceptable limits. The superheaters need to be designed with very large spacing, due to the formation of deposits. The hottest superheaters are not cleaned with sootblowers, as the deposits on the surface create a protective layer against corrosion.

5.1.3.3 Pulverised peat firing

In the late 1970s, pulverised firing proved to be the most mature of all combustion technologies, because it was standard technology with coal. Most large peat-fired power plants in the 1970s and in the first half of the 1980s, were based on boilers with pulverised firing. Pulverised firing of reactive fuels such as peat, however, proved to be problematic because of difficulties in the drying systems. One disadvantage was also the need for support fuel, due to the changes in fuel quality. Late in the 1980s, the need for emission control made the situation even worse.

Pulverised combustion is rarely used for wood residues. The plants are almost always too small for pulverised combustion to be feasible [60, Alakangas, 1998]. However, a few plants still grind wood pellets and use pulverised firing.

Sulphur reduction in the furnace can be implemented by limestone or dolomite injection, but the method is very inefficient and uneconomical. It is even possible that chlorine corrosion is increased by these adsorbents. The principle is the same as the method used in fluidised bed combustion, but the limiting factors are the lower suspension density and sintering effects caused by the higher furnace temperature than that in fluidised bed combustion.

5.1.3.4 Fluidised bed combustion

Two main types of fluidised bed combustion (FBC) boilers exist – bubbling (BFBC) and circulating (CFBC). Fluidised bed combustion is mainly used for industrial applications where different solid fuels such as coal, lignite, peat and particularly biomass are burned. In Finland, BFBC boilers are more popular for the combustion of biomass and peat, especially in small sized boilers and in industry where good availability is important. CFBC boilers are more common in larger plants where coal firing ability is important. In Sweden, CFBC boilers are the most poular boilers today.

Bubbling fluidised bed combustion (BFBC) is a modern combustion technology especially suited for burning inhomogeneous biofuels. BFBC consists of a 0.5 – 1.5 m high bed on a fluidising air distribution plate. The fluidising velocity is about 1 m/s. The density of the bubbling bed is about 1000 kg/m^3. Typical bed materials used are sand, ash, fuel, dolomite, limestone, etc. The particle size distribution in the fluidising bed material is typically within 0.5 – 1.5 mm, as smaller particles are carried out with the fluidising gas flow, and larger particles sink onto the distribution plate.

Circulating fluidised bed combustion (CFBC) differs from BFBC in two ways. The bed material particle size is smaller, i.e. 0.1 – 0.6 mm, and the fluidising velocity is faster, i.e. 4 – 6 m/s. These changes affect the fluidising conditions so that part of the bed material is carried out from the bed, transiting through the furnace to the second pass of the boiler. These particles exiting the furnace are separated from the flue-gas flow by a cyclone or by other separation methods, such as U beams, and recirculated back to the fluidised bed. The separation can be carried out in the middle of the second pass and, in part, also at the outlet of the boiler pass, where electrostatic precipitators and fabric filters can also be used.

In the 1980s, FBC technology took over the peat- and wood-firing market from pulverised- and grate-firing, so that now FBC is mainly used in new plants. These boilers typically have a fuel input of less than 200 MW, and they produce both electricity and heat to local industry or to the district heating system. The peat-fired boilers are usually also designed to combust other low calorific fuels, and sometimes coal. Heavy oil is commonly used as an auxiliary start-up fuel.

In addition, many of the older steam generators with pulverised peat burners with associated peat dryers have been rebuilt to use FBC.

FBC is tolerant for fuel quality changes and there is no need for fuel drying and pulverising.

SO_2 and NO_X control in fluidised bed combustion

When a fuel containing sulphur is combusted, sulphur dioxide and sulphur trioxide are generated. In a circulating fluidised bed, sulphur oxides can be captured by using dolomite or limestone as bed material. Dolomite, or limestone, is calcined in the bed by the influence of heat, and the calcined lime then reacts with sulphur oxides to form calcium sulphate. A 90 % reduction is only possible with sulphur-rich fuels. The bed temperature in CFB (850 ºC) is optimal for calcium-based sulphur recovery.

In a bubbling bed, the combustion mainly occurs in the freeboard zone, and the dense suspension only exists in the bubbling bed. Therefore, the efficiency of sulphur recovery is much lower in the BFBC than in the CFBC. The reduction efficiency in the BFBC is typically 30 - 40 %. A higher efficiency requires high Ca/S mole ratios of up to 10.

The formation of thermal NO_X is avoided in fluidised bed combustion because of the low combustion temperature. Low NO_X combustion is also enhanced in fluidised bed boilers by staging the combustion air. The staging in the CFBC is always quite strong because of the poor horizontal mixing of gases over a dense suspension area. The dense suspension suppresses the turbulence, and the combustion zone of volatile fuel components spreads upwards from the feeding point.

Fuel nitrogen can also form nitrous oxide (N_2O). The share of fuel nitrogen that forms nitrous oxide decreases to an insignificant value if the bed temperature is increased to over 950 ºC. On the other hand, a high combustion temperature can cause an increase in the emissions of nitrogen oxides (NO and NO_2). In the BFBC, the risk of nitrous oxide emissions can be more easily avoided, as the temperature in the freeboard can be kept much higher than 950 ºC.

Strong staging of combustion air can also be implemented in the BFBC. The low NO_X technology of the BFBC is still developing, and different boiler companies have different reduction rates.

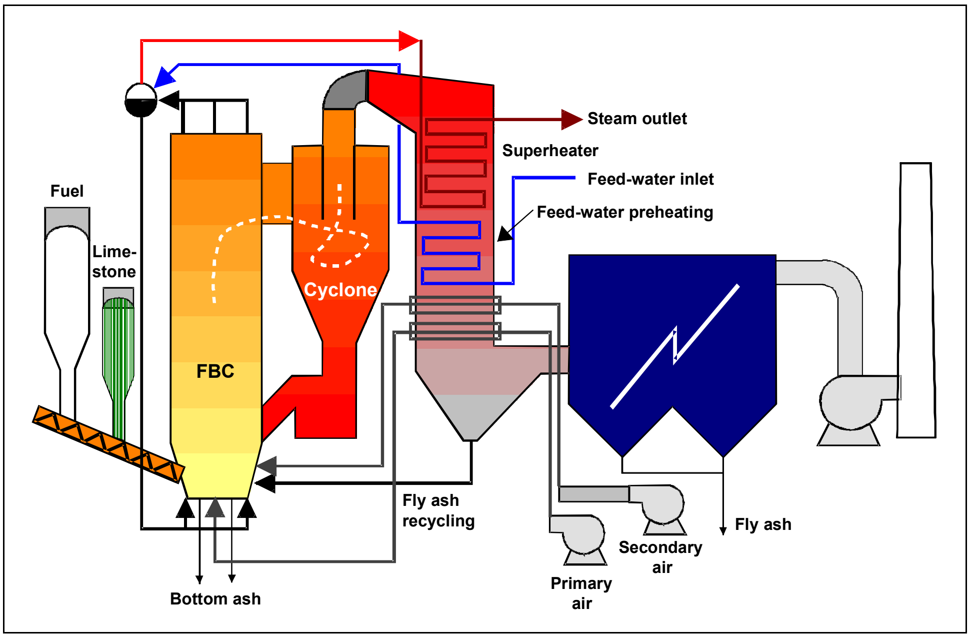


Figure 5.3: Circulating fluidised bed boiler
[59, Finnish LCP WG, 2000]

5.1.3.5 Gasification of biomass

Atmospheric CFB gasification (ACFBG) is a process where solid fuel is converted to combustible gas by partial oxidation. Air is used to fluidise the bed in the CFB reactor, and simultaneously, to oxidise part of the fuel to gas at an elevated temperature.

The atmospheric CFB gasifier (Figure 5.4) consists of a reactor where the gasification process takes place, a cyclone to separate the circulating bed material from the gas, and a return pipe for returning the circulating material to the bottom part of the reactor. After the cyclone, hot product gas flows into the air preheater which is located below the cyclone. The gasification air, blown with the high pressure air fan, is fed to the bottom of the reactor via an air distribution grid. The fuel is fed into the lower part of the gasifier at a certain height above the air distribution grid.

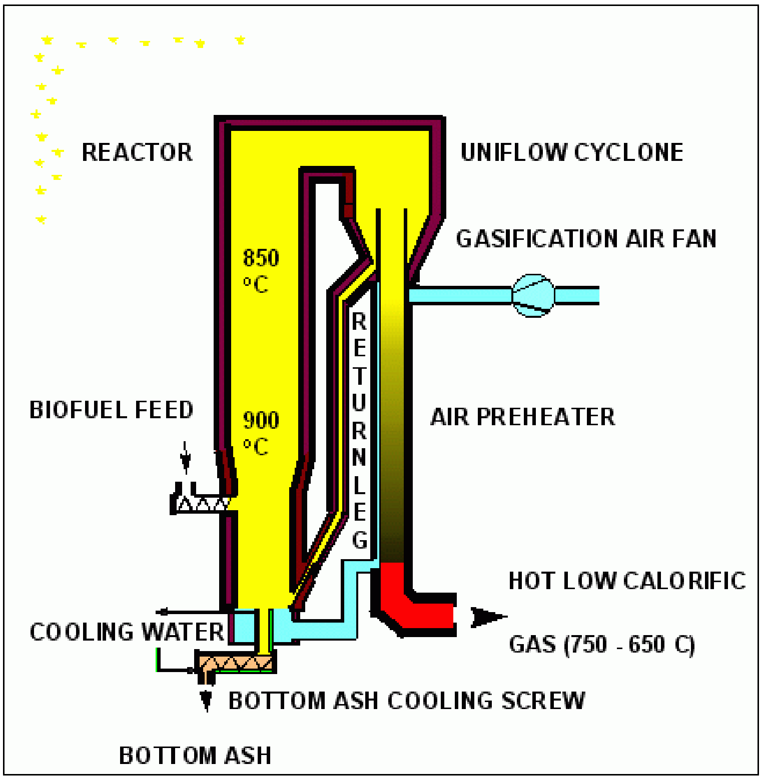


Figure 5.4:Foster and Wheeler gasifier
[192, TWG, 2003]

The operating temperature in the reactor is typically 800 – 1000 °C depending on the fuel and the application. When entering the reactor, the fuel particles dry rapidly and the first primary stage of the reaction, pyrolysis, occurs. During these reactions, fuel converts to gases, charcoal, and tars. Part of the charcoal flows to the bottom of the bed and is oxidised to CO and CO_2, generating heat. After this, as these aforementioned products flow upwards in the reactor, a secondary stage of reactions take place. From these reactions, a combustible gas is produced, which then enters the cyclone and escapes the system together with some fine dust. Most of the solids in the system are separated in the cyclone and returned to the lower part of the gasifier reactor. These solids contain char, which is combusted with the fluidising air that is introduced through the grid nozzles to fluidise the bed. This combustion process generates the heat required for the pyrolysis process and subsequently, mostly endothermic reactions. The circulating bed material serves as a heat carrier and stabilises the temperatures in the process. The coarse ash accumulates in the gasifier and is removed from the bottom of the gasifier

Fluidised beds are, however, quite sensitive to the low softening temperature of biofuel ash. The reducing atmosphere inside the gasifier further decreases the softening temperature of ash. This limits the gasification temperature from above. From below, the gasification temperature is limited because of incomplete gasification, i.e. the increase in tar compounds in the product gas. Tar is harmful to scrubbers when it condenses there. Tar can generate coke in the filters if high temperature dust removal is adopted. Therefore, the technical operating temperature window of biofuel gasification is quite limited, and it can be a big economic drawback in new power plant investments, compared to the conventional power plant technology.

5.1.3.6 Co-generation (CHP)

Co-generation power plants are economically feasible for much smaller plant sizes than condensing power plants. They are also particularly suitable for peat and biomass combustion. With a smaller plant, the peat and biomass fuel can be collected over a smaller area, which helps to keep down the costs and the environmental impact of fuel transport, usually a major cost item in peat and biomass.

Peat and biomass are nowadays mainly used in combined heat and power production due to the fact that the fuel utilisation is high. This is likely to continue. In 1998, about 75 % of the peat fuel in large combustion plants in Finland, for instance, was used in CHP production; the corresponding figure for biomass was 85 %. In Ireland peat is, however, used only for electricity production.

5.1.3.7 Co-firing of biomass and fossil fuels

One of the primary goals and achievements of the co-firing of biomass, for instance together with peat or coal, was the reduction of SO_2 and CO_2 emissions. Due to the replacement of primary fossil fuel, the emission of 'fossil CO_2' decreases, because combustion of biomass is considered to be CO_2 neutral (CO_2 emission from combustion of biomass is fixed again when new biomass grows). CO_2 reduction generally is the argument in favour of the co-combustion of biomass, even though emissions into the air of other components might increase somewhat.

In many cases, the amounts of biomass available at a reasonable cost in any one location is too small to make a power plant based only on biomass economically feasible. The economics of using these locally available fuels may improve considerably if they can be co-fired with a commercial fuel at an existing power plant. However, there are considerable technical and environmental restrictions on fuels that can be co-fired. The co-firing of biomass has been successfully applied at many Finnish FBC power plants, where the main fuel is peat, coal, or wood residue from the pulp and paper industry.

The use of peat also promotes the use of wood and enables the use of more expensive fuels. Due to its characteristics, peat is applicable for co-firing with wood. Technically, it would be more difficult to use only wood fuel in existing plants because of corrosion and fouling problems. The ability to burn peat also assures continuous fuel supply in areas where the availability of wood fuel is insufficient for the fuel demand.

Another approach has to be taken when the local fuel cannot, for technical reasons, be burned together with the commercial main fuel. In this case, a dedicated combustion facility is constructed for the local fuel in connection with the larger power plant. In Denmark, several separate combustion facilities for straw combustion have been constructed in connection with coal- or gas-fired large combustion plants. The gasification of biomass and waste fuels has been demonstrated at a Finnish and an Austrian power plant.

The fluidised bed combustion (FBC) process provides excellent conditions for burning a wide variety of different fuels efficiently with low emissions. The co-combustion of biomass with coal is also an effective way to reduce specific SO_2 emissions.

The CFBC boiler process can be designed to be a multi-fuel boiler, i.e. full capacity can be reached with coal fuels alone, with combined firing or with biomass alone. In the co-combustion of coal and biomass there are separate, independent fuel feeding systems due to the different kinds of fuel handling. These are also needed to ensure flexible and smooth operation in all possible fuel combinations.

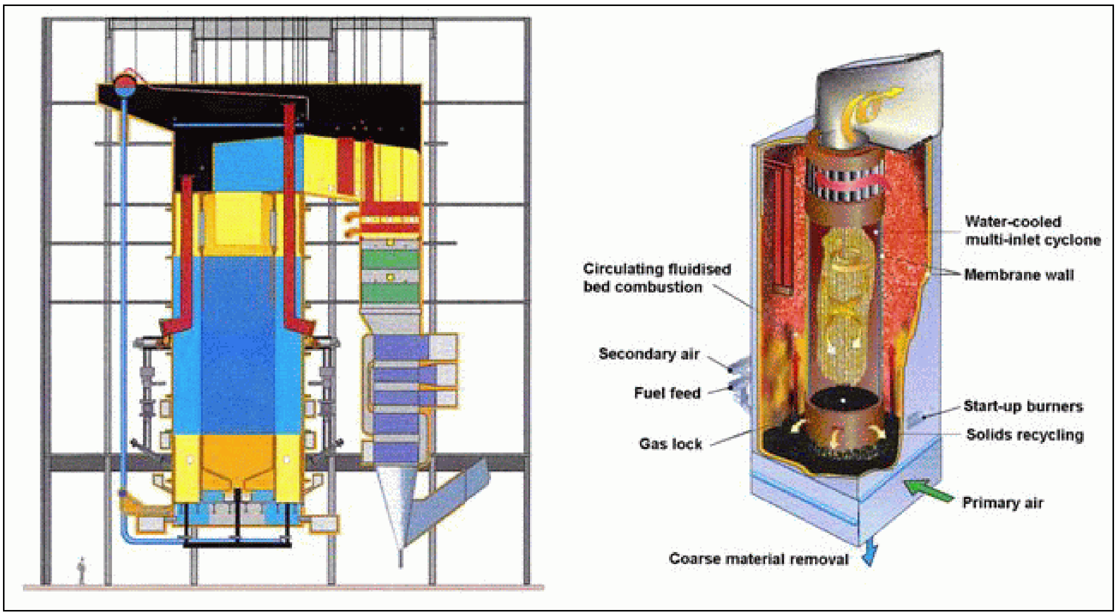


Figure 5.5: Industrial CFB boiler with multi inlet cyclone applied for co-firing [103, Kvaerner Pulping Oy, 2001]

In the bubbling fluidised bed (BFB) process, the fluidising velocity is reduced and there is no return of fines by means of a cyclone system. The BFB process is a highly feasible application for biomass firing.

Low NO_X emissions in the fluidised bed process result from low furnace temperatures added by staged air feeding (typically below 200 mg/Nm^3). For further NO_X reduction, an ammonia injection (SNCR) system can be easily installed (which can achieve emission levels down to, or below, 100 mg/Nm^3, at dry 6 % O_2). SO_x emissions are controlled by limestone injection into the furnace where the conditions for desulphurisation are favourable. The co-combustion of biofuel with coal will further reduce SO_2 emissions and limestone consumption. In coal-biomass co-combustion, all primary emissions are low and specific CO_2 emissions are reduced in proportion to the biomass fuel input.

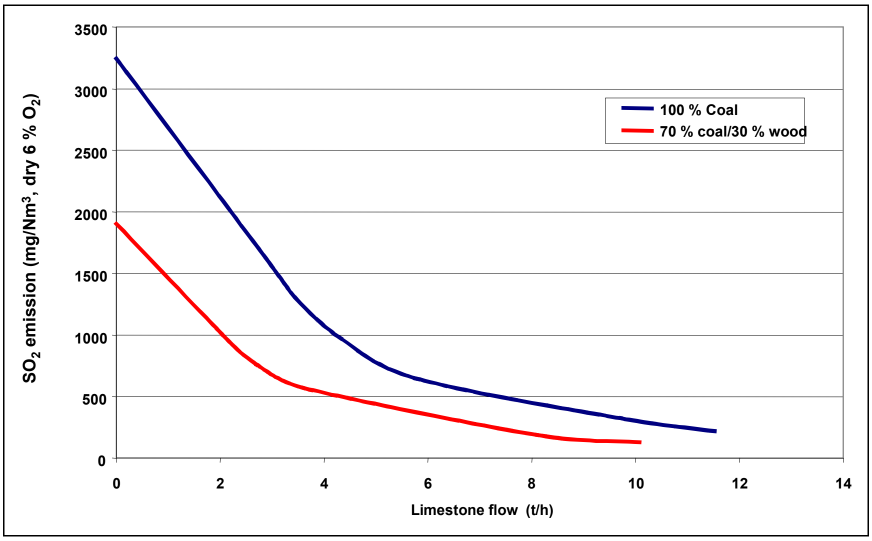


Figure 5.6: The effect of biomass co-combustion on SO_2 emissions (500 MW_{th}, 1.2 % S in coal) [103, Kvaerner Pulping Oy, 2001]

Some experiences with the co-combustion of biomass and other fuels, mainly coal and lignite are presented below:

1. Up to 20 % wood has been co-fired in a power plant in Denmark. This is a front-fired boiler with natural circulation and a capacity of 125 MW_e. Pulverised wood was burned in two specially adapted burners. No negative effects were noticed and it was expected that higher co-firing percentages should be possible. The NO_X emission dropped by 35 %. Straw and to a lesser extent, wood from energy crops (willow) are the most important biomass fuels in Denmark. The high potassium chloride content of straw is a well-known cause of severe slagging and corrosion problems.
2. Tests have been performed with straw in a Danish power plant (150 MW_e). Up to 25 % co-firing was tested in campaigns varying from four weeks to four months. The main conclusions were:

   - NO_X and SO_2 emissions decreased, HCl- and dust-emissions increased
   - a small increase in corrosion rate of the superheater was noticed. The total duration of the tests was too short to quantify this (it was estimated that there would have been a 50 % increase with a 10 % co-firing proportion)
   - when more than 10 % straw is co-fired, the alkali content of the fly ash exceeds the limit for application in cement. For application in concrete, this value is above 20 % co-firing
   - $deNO_X$ catalyst samples exposed to the flue-gas show a quick decrease in activity.

3. Biomass briquettes are co-fired in a lignite-fired power plant in Germany (280 MW_e). There are no problems when firing amounts of up to 10 % (mass based).
4. Up to 7 % (mass based) pressed olive stones (wood from pressed olive stones) was co-combusted in a power plant (Greece), consisting of three lignite-fired units with a total installed capacity of 550 MW for a period of about six months. Special characteristics of the pressed olive stone compared to the raw lignite were: its much higher calorific value, the remarkable lower moisture and ash content and its higher content of volatile matter. As far as the ash composition is concerned, much higher alkali metal oxide concentration and lower percentages of silica and alumina compounds have been featured, resulting in the lowering of melting temperatures. The experiments showed no changes in steam operating parameters (mass flow, temperature and pressure), slagging, and the content of unburned fuel in the ash. Due to the significantly lower sulphur content of the pressed olive-stone, SO_2 emissions were reduced.
5. Co-combustion of biomass in pulverised coal-fired boilers in the Netherlands is performed at 3 % on a thermal basis. In some plants, the biomass is pulverised together with the coal. References with separate milling and with gasification of waste wood are described in parts of the Section 8.1.3. Initiatives to work at higher amounts are under development.
6. Wood has been co-fired in a US power plant. The wood is ground in separate mills and fed to the lowest row of burners. Up to 10 % co-firing gave hardly any problems apart from a high unburned carbon content in the bottom ash (smouldering heaps of wood were visible in the bottom ash discharge).
7. In another US power plant, up to 5 % wood was co-fired. The wood was ground together with the coal. This was the limiting factor due to a lack of spare milling capacity. The influences on boiler operation and efficiency were reported to be negligible.
8. A one-off amount of 124 tonnes of wood was co-fired in a 100 MW_e power plant in Georgia (US). This consisted of a mixture of sawdust and tree lopping. The co-firing percentage varied between 9.7 – 13.5 % of the normally fired coal. In order to maintain boiler efficiency good burn-out was achieved by operating a sufficiently high excess air level (4.2 % O_2 at the economiser). As the heat distribution in the boiler changed, the superheater temperature decreased.

9. In a 54 MW_e power plant (Georgia, US), a short test was performed with up to 40 % (energy basis) wood co-firing. The boiler was only slightly modified. Natural gas was also co-fired at full loads to obtain a stable flame (36 % wood, 17 % gas, and 47 % coal). The boiler efficiency decreased due to the moisture content of the wood and due to the unburned carbon in the ash.

5.1.4 Flue-gas cleaning

5.1.4.1 Control of emissions from grate firing

When burning biomass (e.g. wood, straw, etc.) or peat in grate combustion systems, most of the ash is left on the grate and collected as bottom ash. Only a small quantity of ash leaves the furnace as fly ash and must be collected in the dust reduction devices.

5.1.4.1.1 Dust abatement

For dust abatement from grate-fired combustion plants, both ESPs and fabric filters are currently applied, with the fabric filter being more commonly applied.

5.1.4.1.2 Abatement of SO_2 emissions

Sulphur removal on the grate is not possible because of the minimal contact time between the sulphur oxides and the reactive alkali fed onto the grate. Limestone injection into the furnace is possible, but it is not efficient. At smaller grate-fired power plants using biomass and peat the sulphur content of the fuel is low or often moderate. Therefore, emissions are frequently so low that no desulphurisation is needed.

With higher sulphur content peat, dry injection processes are usually applied. The injection of calcium hydroxide in a dry form before the baghouse can achieve a high enough reduction. In the furnace, limestone injection together with a calcium oxide activation scrubber, is also quite effective in some cases. These measures also remove other harmful emissions, such as HCl.

5.1.4.1.3 Unburned carbon in ash

Regarding the content of unburned carbon in ash for grate firing, the target is to achieve the best burnout possible in order to attain the optimum efficiency or fuel utilisation. However, according to technical and fuel chracteristics, a higher content of unburned carbon in ash may happen in the grate firing of biomass.

5.1.4.1.4 Abatement of NO_X emissions

The low combustion temperatures of grate systems are advantageous for the suppression of NO_X emissions. However, a SCR catalyst will quickly, typically after approximately only 100 hours of operation, become deactivated, which will then lead to a significant decrease in the reduction rate of NO_X. Overfire air is sometimes used to reduce the generation of NO_X emissions.

NO_X reduction mechanisms are the same as with bubbling fluidised bed combustion. Efficient low NO_X combustion requires a sophisticated secondary air system and a special furnace design enabling two combustion zones.

The high-dust SCR is not a viable solution for plants fired with straw or wood, as it leads to the SCR being poisoned by the formation of potassium salts. Furthermore, regeneration of a poisoned SCR is very expensive.

5.1.4.2 Control of emissions to air from pulverised peat combustion

5.1.4.2.1 Dust abatement

In pulverised peat combustion, the bulk of the ash is carried with the flue-gas out of the combustion chamber. Only a small quantity is collected as bottom ash.

Among dust removal technologies, the ESP is (by far) the most commonly used equipment in power plants in Europe. ESPs collect fly ash, generally in a dry form, that can then be landfilled or recycled for use in road building or for manufacturing products such as cement and concrete. Fabric filters may also be used in pulverised peat combustion plants.

5.1.4.2.2 Abatement of SO_2 emissions

At power plants using peat, the sulphur content of the fuel is low or often moderate. Therefore, emissions are frequently so low that no desulphurisation is currently applied.

Dry injection processes are usually applied for higher sulphur content peats. Calcium hydroxide injection in a dry form before the baghouse, can achieve a high enough reduction rate. In the furnace, limestone injection, together with a calcium oxide activation scrubber, can also be quite effective in some cases. These measures also remove other harmful emissions, such as HCl.

5.1.4.2.3 Abatement of NO_X emissions

Since the combustion temperatures in burning peat are lower than the temperatures of, for instance, hard coal combustion, nitrogen oxide emissions are reduced by combustion technology (staged air supply system) and/or use of SNCR.

5.1.4.3 Control of emissions from the fluidised bed combustion of biomass and peat

For fluidised bed systems, fuel is used in a coarsely ground form and for this reason most ash is extracted as bottom ash. In Circulation Fluidised Bed Combustion systems (CFBC) the bed zone is expanded by higher airflow velocities and ash (necessary for this type of combustion) has to be recirculated from flue-gas side measures. Centrifugal precipitation is an integral component of CFBC to recover coarse ash particles, as shown in Figure 5.7.

Figure 5.7: Fuel and bed material flow in a biomass fired CFBC boiler
[91, Kokk, et al., 2000]

5.1.4.3.1 Dust abatement

For dust abatement in biomass and peat-fired fluidised bed combustion (FBC) boilers, both ESPs and fabric filters are currently applied, where the fabric filter is often the preferred technique.

5.1.4.3.2 Abatement of SO_2 emissions

The degree of desulphurisation in peat-fired FBC boilers is significantly lower than in coal-fired FBC boilers. According to the knowledge gained with peat in a Finnish FBC, the degree of desulphurisation with moderate Ca/S ratios (3 – 5) for both peat-fired CFBC and BFBC is around 30 – 40 %. The desulphurisation does not increase over about 45 % in the BFB boiler, even with much higher Ca/S ratios. In CFBC, the highest achievable degree of desulphurisation was around 80 %, but that could only be reached with a very high Ca/S ratio. A high Ca/S ratio jeopardises the re-use of precipitated fly ash, which means that lower reduction rates (and sorbent amounts) are recommended.

Sorbent use increases the amount of ash produced by the power plant. There is a possibility of reduced efficiency in electrostatic precipitation, due to the sorbent properties. This causes more particulate emissions, especially when using larger amounts of sorbent to reduce the sulphur oxide emissions.

5.1.4.3.3 Abatement of NO_X emissions

NO_X emissions in fluidised bed combustion (FBC) are usually noticeably lower than in conventional pulverised fuel combustion. The combustion temperature in FBC is typically low, which guarantees a low level of thermal NO_X formation. Basically under these conditions, all NO_X emissions are caused by fuel-bound nitrogen.
The NO_X formation in FBC can be further limited by minimising the excess-air ratio and by staging the combustion air. In modern fluidised bed boilers, secondary air ports are installed in addition to the fluidising air inlets. Some combustion air is injected through these separate ports, which are located in the upper part of the furnace on levels 1 to 3. Thus, the lower part of the furnace can be operated with a low air ratio, which inhibits NO_X formation. Secondary/tertiary air injected through the upper air ports ensures a complete burn-out. The production of nitrous oxide (N_2O) appears to be greater in FBC (especially in circulating fluidised beds) than in conventional pulverised fuel combustion, due to the slower degradation of the compound at the lower combustion temperatures.

Secondary measures such as selective or non-selective catalytic reduction processes (SCR or SNCR) are also possible and have been applied to biomass-fired FBC boilers in Sweden and Finland. SNCR has been used widely in these countries for many years and is considered to be well established technology for biomass firing. (Typically, NO_X emissions: 40 – 70 mg/MJ; and NH_3 emissions: 3 – 10 ppm). SCR was introduced in the mid 90s. There are now six boilers operating with SCR within the energy sector. Five of these are fluidised beds (CFBC/BFBC) for co-generation and one is a small (40 MW – mixture biomass/peat) grate for co-generation. For all FBC boilers, it has been considered favourable to apply a combination of SNCR and SCR (high dust). The grate has a (low dust) SCR alone. Typically NO_X emissions after SCR are below 30 mg/MJ (<90 mg/m^3).

One problem with the SCR is the deactivation of the catalyst, which is faster when firing biomass compared to coal. Results from wood fired FBC boilers show that the catalyst loses 20 – 25 % (average) of its relative activity during a normal heat production season.

The relatively high deactivation rate is mainly due to the high alkali (mainly potassium) content in the flue-gases. This means there is a need to regenerate the catalysts. This can be achieved (e.g. every second year) by washing the catalyst with water (and/or sulphuric acid), after taking the catalyst out of the system. However, there are also promising results from tests aiming for an *in situ* washing by water followed by sulphation (treatment with SO_2 gas). For improving the technical and economic feasibility of SCR for biofuels, more research is needed.

5.1.5 Water and waste water treatment

Pollutant emissions to water or soil are not a major problem for large peat or biomass combustion plants.

5.1.6 Handling of combustion residues and by-products

A peat-fired power plant produces ash and products from limestone injection. Most of the ash is fly ash from the flue-gas cleaning system (electrostatic precipitators or fabric filters). Some 10 – 20 % of the total ash amount is bottom ash on the bottom of the boiler. These materials can be used or disposed of.

Nowadays peat is seldom fired alone, but is usually fired together with other fuels, such as wood. Therefore, in most cases mixed ash is produced. The properties of such mixed ash are different from those of peat ash and, therefore, the utilisation opportunities are slightly different.

Peat ash can be used as a raw material and an additive in the construction and building material industry and, e.g. as a road construction material. It may also be used in sewage treatment. The geotechnical properties and mineral constituent of ash have to be investigated on a case-by-case basis before commercial use.

The co-combustion of wood and peat results in a slightly different composition of ash, which makes it more difficult to use it as construction material.
In the stabilisation of mineral aggregate and in concrete, peat fly ash can be utilised to replace either the finest aggregate material or part of the cement.

Ash from a peat-fired power plant can be transported, e.g. to bog areas. Disposal of ash on cut-away bogs is environmentally acceptable and also economically sensible. In some countries, such as Ireland, ash must be disposed of to controlled landfills, but even then the quality of the ash must have first been tested (e.g. solubility testing) and later, environmental monitoring of the landfill site must be carried out.

Environmental and health aspects are taken into account in site planning. As far as landfilling is concerned, peat ash and coal ash are quite similar. Some temporary nuisance, due to dust or noise caused by traffic and working machines, might occur. Landscaping of the site will adapt cut-away bogs to the surrounding landscape.

Peat fly ash may be used as fertiliser on the forest and fields. Peat ash contains some plant nutrients and lime necessary for plants. However, both environmental and health aspects and regulations have to be taken into account before there is any commercial use of peat ash as a fertiliser.

The fly ash from straw combustion units is disposed of primarily due to its high content of cadmium. The bottom ash is normally taken back to the fields or used as a road construction material.

5.2 Examples of applied processes and techniques

This part of Chapter 5 provides a number of examples of techniques and processes currently applied in different biomass combustion installations. The aim of the examples is to demonstrate how specific techniques have been applied to new or retrofitted plants in order to ensure a high level of protection for the environment as a whole, taking into account, in each case, the particular site-specific conditions and environmental requirements. However, from the information collected, it is not always clear, if or how each technique described in the examples has been assessed against the definition of BAT given in article 2 (11) of the Directive, as well as against the list of ‘considerations to be taken into account generally or in specific cases when determining the best available techniques bearing in mind the likely costs and benefits of a measure and the principles of precaution and prevention’ and, consequently, how the technique has been selected and applied. Furthermore, it cannot be assured that the environmental performance presented is constant and continual under all operational conditions, over which time period, whether any problems have been encountered, and what the cross-media effects are. Also, it is not always clear what the driving force is for applying the technique and how the costs and environmental benefits are related in each case. Therefore, the information provided in the following examples is meant only to provide general indications of reported current practice and cannot be considered as appropriate reference points. The techniques that are given as examples arise from information provided and assessed by members of the Technical Working Group as part of the information exchange of LCPs.

5.2.1 Individual techniques to reduce emissions from biomass- and peat-fired large combustion plants

EXAMPLE 5.2.1.1 DESULPHURISATION WITH LIMESTONE INJECTION TO PEAT-FIRED CFBC AND BFBC BOILERS (CASE STUDY)

Description: The maximum SO_2 removal efficiencies of limestone injection were tested and the costs of desulphurisation analysed at an existing peat-fired CFBC plant and at an existing peat-fired BFB plant. The aim of the study was to determine the highest achievable level of desulphurisation possible in existing peat-fired FBC plants with an *in situ* injection of limestone in the bed and also to evaluate the costs of the desulphurisation.

Achieved environmental benefits: In the CFB boiler, the lowest achievable emission level of 200 mg/Nm^3 (O_2 = 6 %) was reached with a Ca/S ratio of 10, when the sulphur content of the fuel was 0.17 %. The CFB plant operates normally at an emission level of 360 mg/Nm^3 (O_2 = 6 %) with Ca/S ratio 2 – 4 (depending on the limestone). In the BFB boiler, the highest achievable degree of desulphurisation was around 45 % with a Ca/S ratio of 7, when the sulphur content of the peat was 0.25 %. The SO_2 emission was 280 mg/Nm^3 (O_2 = 6 %). Further limestone addition did not result in a higher degree of desulphurisation. The normal operation of that BFB plant at 360 mg/Nm^3 (O_2 = 6 %) level resulted from a Ca/S ratio of between 2 and 4.

Boiler	CFB	BFB
S content in the fuel (%)	0.17	0.25
NORMAL OPERATIONAL LEVEL		
SO_2 emission (mg/Nm^3 (O_2 = 6 %))	360	360
Ca/S ratio	2 – 4	2 – 4
Cost of desulphurisation (EUR/t SO_2 removed)	1300	1400
MINIMUM ACHIEVABLE EMISSION		
SO_2 emission (mg/Nm^3 (O_2 = 6 %))	200	280
Ca/S ratio	10	7
Cost of desulphurisation (EUR/t SO_2 removed)	1800	1950
Marginal cost for desulphurisation between normal emission level and achievable level (EUR/t SO_2 removed)	2100	2700
Cost of desulphurisation with semi-dry spray tower technology (EUR/t SO_2 removed)	6800	3200

Table 5.1: Summary of the results of the case study

An evaluation was also made of what the desulphurisation would have cost if the semi-dry spray tower technology had been applied. As can be seen from Table 5.1, these costs were far higher than those of the *in situ* addition of limestone in the bed.

Economics: It can be seen that the total cost of desulphurisation at normal operational level (SO_2 emission 360 mg/Nm^3 (O_2 = 6 %) in both plants) was around EUR 1300/t SO_2 removed in the CFBC boiler and EUR 1400/t SO_2 removed in the BFB boiler, both of which are considerably higher than the cost per reduced tonne of SO_2 in pulverised coal combustion with wet scrubbing. When increasing the degree of desulphurisation to the lowest achievable levels, 200 mg/Nm^3 (O_2 = 6 %) for CFBC and 280 mg/Nm^3 (O_2 = 6 %) for BFB, the marginal costs for this extra desulphurisation were around EUR 2100/t SO_2 removed and EUR 2700/t SO_2 removed, respectively.

Driving force for implementation: Reduction of SO_2 emissions.

Reference literature: [59, Finnish LCP WG, 2000], [100, Kouvo and Salmenoja, 1997].

5.2.2 Improving the environmental performance of existing biomass- and peat-fired large combustion plants

EXAMPLE 5.2.2.1 CONVERSION OF AN OLD PULVERISED PEAT BOILER TO A MODERN FLUIDISED BED BOILER

Description: In 1996, the combustion technology of an example plant operated in Finland was converted from a 20-year old pulverised peat boiler into a bubbling fluidised bed boiler. To convert the old plant, the complete front of the original boiler was replaced in order to install the new combustion arrangement. With the new technology, the boiler became a multi-fuel boiler. At the same time, the boiler's capacity was increased by 20 %.

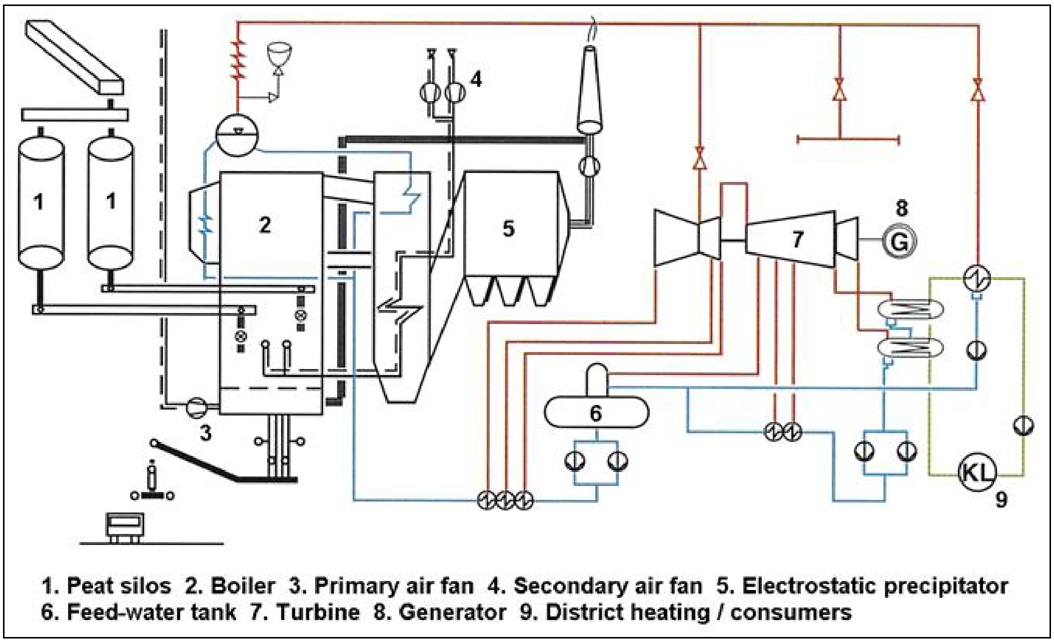


Figure 5.8: BFBC boiler converted from a pulverised peat boiler
[99, Oulun Energia, 1997]

Achieved environmental benefits: The fluidised bed combustion technology has reduced the amount of nitrogen emissions in the flue-gas to about half of the previous amounts. Dust emissions were also reduced because of the fully renovated ESP.

Applicability: The concept of converting an existing pulverised peat boiler into a modern fluidised bed boiler is in principle transferable but has to be validated on a case-by-case basis.

Cross-media effects: Higher efficiency.

Operational data: The plant is operated as a co-generation (CHP) plant:

steam power	242 MW
steam temperature	540 °C
fuel efficiency	90 %.

Economics: Mot available.

Driving force for implementation: Low emission levels of NO_X and dust, achieving higher efficiency and prolonging the lifetime of the plant.

Reference literature: [99, Oulun Energia, 1997].

EXAMPLE 5.2.2.2 CO-COMBUSTION OF BIOMASS IN A POWER PLANT FIRED WITH PULVERISED BLACK LIGNITE

Description:. In 1996, the co-combustion of mouldings made from different biomass sources was tested in several experiments in different units (A and B) of the example power plant. The results of the co-combustion experiments are presented here.

Co-combustion of mouldings in unit A

Unit A has a rated thermal input of 280 MW and gross power output of 108 MW_e. Black lignite is fired and thus a DeNOX plant, with an SCR technique in high-dust configuration, was necessary in addition to the primary measures. Furthermore, an ESP and a wet FGD were installed. For co-combustion, no additional installations were required. The mouldings were mixed with the lignite at the storage area, which produced fairly high emissions of dust. The mouldings were cylindrically-shaped, had a diameter of about 25 mm and were made from three different biomass sources:

- straw
- cereal plants
- pasture from landscape cultivation.

Four experiments were carried out on weekends, each for a 24 hour time period, with mouldings of each type. Additionally, co-combustion of mouldings from straw was tested over a three week period. The share of biomass in the total thermal input ranged from 4.6 to 13.3 %.

Co-combustion of waste wood chips in unit B

Unit B has a rated thermal input of 803 MW and a gross power output of 316 MW_e. The configuration of the emission control is identical to the one of unit A. The wood chips were fed into the coal bunkers where they mix with the lignite. As the wood chips are virtually unground in the coal mills, they fall down onto the afterglow grate where they partly burn in a floating bed. The big, unburned particles of the boiler ash are fed back to the coal bunker. The concentration of impurities in the wood chips must not exceed certain values (see Table 5.2). Waste wood treated with halogenated finish or with wood preservatives containing heavy metals must not be fired. Since June 1999, about 300 – 350 tonnes of waste wood chips have been fired every day, representing about 12 % of the mass input and 8 % of the thermal input.

Achieved environmental benefits: The co-combustion of biomass saves fossil resources and reduces emissions of CO_2. The co-combustion of wood chips in unit B reduced the consumption of black lignite by approximately 80000 tonnes per year.

Applicability: The possibility for co-combusting biomass is plant specific.

Operational data:

Co-combustion of mouldings in unit A

The mean qualities of lignite and three biomass fuels used for the co-combustion experiments are displayed in Table 5.2:

	Black lignite	Mouldings made from		
		Straw	Cereal plants	Pasture from landscape cultivation
Calorific value (MJ/kg)	17.08	15.51	15.05	15.44
Water content (%)	29.2	10.45	10.7	7.0
Ash content (%)	10.25	6.89	4.34	6.79
Chlorine	0.003	0.366	0.034	0.216
Sulphur	1.03	0.079	0.08	0.077
Potassium	0.07	1.26	0.47	1.55

Table 5.2: Mean qualities of the fuels used for the co-combustion experiments

The operation of the coal mills were tested with biomass proportions ranging from 10 to 40 %. More than 40 % biomass could not be handled by the mills. Table 5.3 shows the resulting size-distribution of the fuel after grinding in the coal mills. It can be seen that for a 10 % proportion of biomass, the distribution changes only slightly, whereas for higher proportions, the share of the very fine particles (<0.09 mm) strongly decreases. This means, that it is not only the biomass, that is badly ground, but the grinding of the coal is also affected by the presence of high proportions of biomass.

	Share of size dependent groups in total fuel mass after grinding in coal mill (%)			
Fuel characteristics	**>1.0 mm**	**>0.2 mm**	**0.09 – 0.2 mm**	**<0.09 mm**
coal only	7	24	19	50
10 % straw	7	27	16	48
27.5 % straw	19	36	14	31
19.2 % cereal plants	23	35	16	26
20.0 % pasture from landscape cultivation	22	43	15	20

Table 5.3: Quality of milled fuels for different proportions of biomass

Increased slagging occurred only during the three weeks co-combustion of straw mouldings. The SCR and the ESP were not influenced. The emissions to the air from the different tests are shown in Table 5.4.

	Units	Coal only	Co-combustion of mouldings from				
			Straw	Straw	Cereal plants	Pasture from landscape cultivation	Straw (three weeks-testing)
Share in thermal input	%	-	4.6	13.3	8.43	9.7	11
Nitrogen content in fuel-mix	mg/kg	9400	9200	8370	8640	8490	8900
NO_2 in raw gas	mg/Nm^3	442	411	400	387	398	419
NO_2 after SCR	mg/Nm^3	132	132	131	127	130	135
Dust after ESP	mg/Nm^3	17.7	19.6	36.5	26.9	43	85
Dust after FGD	mg/Nm^3	2.8	3.2	2.5	2.7	2.9	5.9
SO_2 in raw gas	mg/Nm^3	2870	2800	2600	2733	3111	2842
SO_2 after FGD	mg/Nm^3	125	125	119	110	138	116

Table 5.4: Atmospheric emissions: comparing the five different co-combustion tests and singular coal firing

The following conclusions can be drawn from the measurements of the atmospheric emissions:

- NO_2 concentrations in the raw gas decrease slightly due to co-combustion
- the concentration of dust in the flue-gas after the ESP increases, probably due to the higher concentration of fine particles; the separation of dust in the FGD ensures low concentrations in the clean gas
- the sulphur contents of the biomass fuels are, in general, about ten times smaller than those of the coal. Thus a reduction of SO_2 concentrations can be observed. The emissions of HCl are about three times higher for co-combustion due to the high content of chlorine, but the emissions are still only 1 % of the ELV. The increase of halogens might, in the long run, also corrode parts of the FGD
- PCDD/PCDF could not be measured for singular coal combustion. For co-combustion, measured values ranged slightly above the detection limit (0.001 – 0.002 ng TEQ/Nm^3).

The quality of residues (fly ash, boiler ash, gypsum sludge) is only slightly influenced. The disposal of these residues together in the opencast mine as stabilised material is also possible for co-combustion.

Furthermore, the temperature of the flue-gas rises under co-combustion conditions by 5 to 10 °C and the share of combustible matter in the ash nearly doubles to 8 %. These effects lead to a reduction of the boiler efficiency.

Co-combustion of waste wood chips in unit B

Here, the results of the test which took place in 1998, are presented. During 370 hours of operation, about 5400 tonnes of waste wood chips were fired. The share of the wood chips in the total fuel mass input amounted to 11.4 %. The characteristics of the coal and the wood chips and the maximum concentrations of impurities in the wood chips are shown in Table 5.5.

	Units	**Coal**	**Wood chips**
Calorific value	MJ/kg	16.4	13.3
Bulk density	t/m^3	0.95	0.24
Energy density	GJ/m^3	15.6	3.2
Chip size	mm	-	1 – 60: 96 % 60 – 100: 3 % >100: <1 %
Maximum concentrations of impurities			
B	mg/kg	-	30
Cl	mg/kg	-	300
F	mg/kg	-	30
As	mg/kg	-	2
Cu	mg/kg	-	20
Hg	mg/kg	-	0.4
PCP	mg/kg	-	2
Benzo(a)pyrene	mg/kg	-	0.1

Table 5.5: Characteristics of the coal and the wood chips and the maximum allowed concentrations of impurities in the wood chips

The atmospheric emissions during co-combustion in 1999 are shown together Table 5.6.

	Unit	**Mean value from three singular measurements in 1999 at 7 % O_2**
Dust	mg/Nm^3	8
CO	mg/Nm^3	35
NO_2	mg/Nm^3	117
SO_2	mg/Nm^3	103
Total carbon	mg/Nm^3	2.3
HCl	mg/Nm^3	1.1
HF	mg/Nm^3	<0.1
Cd, Tl	mg/Nm^3	0.001
Hg	mg/Nm^3	0.002
PCDD/PCDF	ng TE/Nm^3	0.0025

Table 5.6: Measured emission values for the co-combustion of waste wood chips

The emissions of metals and dioxins/furans did not change due to co-combustion.

Economics: The specific costs (EUR/MJ) for biomass mouldings are about four times higher than for coal. The investment for the upgrading for the co-combustion of wood chips amounted to EUR 0.7 million. The costs for the handling of the wood chips and the logistics inside the power plant amount to approximately EUR 8 – 10/t.

Driving force for implementation: The co-combustion of biomass mouldings was only tested but is not carried out on a regular basis. However, the co-combustion of waste wood chips does occur, as the additional payment for the co-combustion and the savings in coal allow it to operate economically.

Reference literature: [142, Schmidt and Dietl, 1999], [143, Kindler, et al., 2000].

5.2.3 Environmental performance of new biomass- and peat-fired large combustion plants

EXAMPLE 5.2.3.1 CIRCULATING ATMOSPHERIC FLUIDISED BED COMBUSTION BOILER FOR BIOMASS- (WOOD) FIRING

Description: The plant consists of two identical units with a rated thermal input of 2 x 45 MW, a gross electrical power of 19.8 MW_e and a net electrical power of 13 MW_e. The units were erected in 1992 and 1996 respectively, and are used in a chipboard factory to produce electricity and process heat from wood residuals. The flue-gas cleaning system consists of a pulse-jet fabric filter for dust removal. The NO_X emission levels can be achieved by the relatively low combustion temperature, by air staging (three stages for the combustion air inlet) and by flue-gas recirculation. Because of the low sulphur content of wood, no lime needs to be added. Thermal oil is used in the process for heat transfer.

Achieved environmental benefits: The firing of wood can be assumed to be nearly CO_2 free (assuming sustainable forestry). The fuel is a by-product of the chipboard production and, therefore, does not need to be transported any further. Only wood free from contamination by wood preservatives is burned. The production of electricity and process heat allows for an overall energy (fuel) efficiency of 85 %. Waste water occurs only in small amounts (0.3 m^3/h; 2592 m^3/yr in 1999) and is fed into the municipal sewerage system.

Applicability: Fluidised bed combustion is well known for the wide range of fuels which can be burned. Therefore, there should be no limitations due to the fuel fired. Due to the compact design of these plants, the space demand is quite small.

Cross-media effects: The operation of the boiler and the removal of produce a certain amount of ash.

Operational data: In 1999, 102589 MWh_e of net electricity and 634223 MWh of process heat (= 74456 tonnes of steam) were produced. In that year, a net electric efficiency of 15.8 % and a net thermal efficiency of 68 % were achieved. The overall energy efficiency was 85 %. The two units were in operation for 8021 and 6031 hours respectively mainly in part load.

	Monitoring	Measured emissions at 7 % O_2	
		Unit 1	Unit 2
O_2-content (%)		5 – 5.5	6.5 – 7.5
Flue-gas volume (m^3/h)		33153	86453
Dust (mg/Nm^3)	Continuous	$4^{1)*}$	$2.2^{1)*}$
SO_2 (mg/Nm^3)	Continuous	$2.9^{1)*}$	$2.3^{1)*}$
NO_X (mg/Nm^3)	Continuous	$164^{1)*}$	$339^{1)*}$
CO (mg/Nm^3)	Continuous	$147^{1)}$	$178^{1)}$
HCl (mg/Nm^3)	Continuous	$7.3^{1)*}$	$8.8^{1)*}$
HF (mg/Nm^3)	Individual	0.04	0.1
Dioxins/Furans (ng TEQ/m^3)	Virtually continuous	0.013	0.006
Σ Cd,Ti (mg/Nm^3)	Individual	0.004	0.003
Hg (mg/Nm^3)	Individual	0.001	0.001
Σ Heavy Metals (mg/Nm^3)	Individual	0.015	0.006
Total organic C (mg/Nm^3)	Individual	2.0	2.0
Notes: 1) Annual mean value * Equivalent to daily mean values			

Table 5.7: Emission to the air in 1999

The two units consumed 360916 t/yr (25.8 t/h) wood, 170000 Nm^3/yr natural gas, and 3943 t/yr of light fuel oil. The wood is fed into the combustion chamber from two bunkers with wood chips and from two bunkers with wood dust. The average wood properties are given in Table 5.8.

Property	Value
Lower calorific value (MJ/kg)	14.7
Sulphur content (wt-%)	<0.1
Water content (wt-%)	18
Ash content (wt-%)	4

Table 5.8: Characteristics of the wood burned

Water discharges (0.3 m^3/h) result from the ash cooling and from the feed-water treatment. After neutralisation, the waste water is discharged to the sewer. The only residues from the process are ashes.

	Bottom ash	Fly ash
Quantity (t/yr)	1314	7726
Specific Quantity (g/kWh_e)	13	75
Utilisation/Disposal	Dump cover (market price: EUR 25/t)	Filling material for mining (market price: EUR 50/t)

Table 5.9: Quantities of ashes generated in 1999

Economics: The investment for the whole plant amounted to EUR 51.3 million. The full cost for the production of steam amounted to EUR 8.46/t and to EUR 0.077/kWh_{el}.

Driving force for implementation: The motivation for building the plant was to enable the use of production residues for energy generation.

Reference literature: [98, DFIU, 2001].

EXAMPLE 5.2.3.2 CHP PLANT WITH A SHREDDER STOKER BOILER AND A FABRIC FILTER FOR STRAW FIRING

Description: A plant located in Denmark (plant A), is steam driven, with a stoker screw grate-fired wet bottom boiler, with air staging applied. The grate is both sloped and vibrated. The plant is a further development of the technology of another straw firing plant in Denmark (plant B). The difference between the plants is that the steam temperature is raised from 520 °C to 540 °C in the boiler. The district heating temperature applied in plant A is 85 °C, resulting in a lower pressure, compared to plant B where the district heating temperature is 95 °C, thus leading to a higher electrical efficiency. The turbine is more efficient. The result is a 10 % rise in the electrical efficiency. The total capacity of the plant is 10 MW_e and 20 MJ/s heat. The total heat generation is estimated to be approximately 400 TJ yearly. Through co-generation, the fuel energy utilisation is up to 30 per cent better than when the electricity and heat are generated separately. The district heat production covers 90 per cent of the heat demand. The annual straw consumption is approximately 40000 tonnes. At full production in the winter period about 200 tonnes of straw is burned every day.

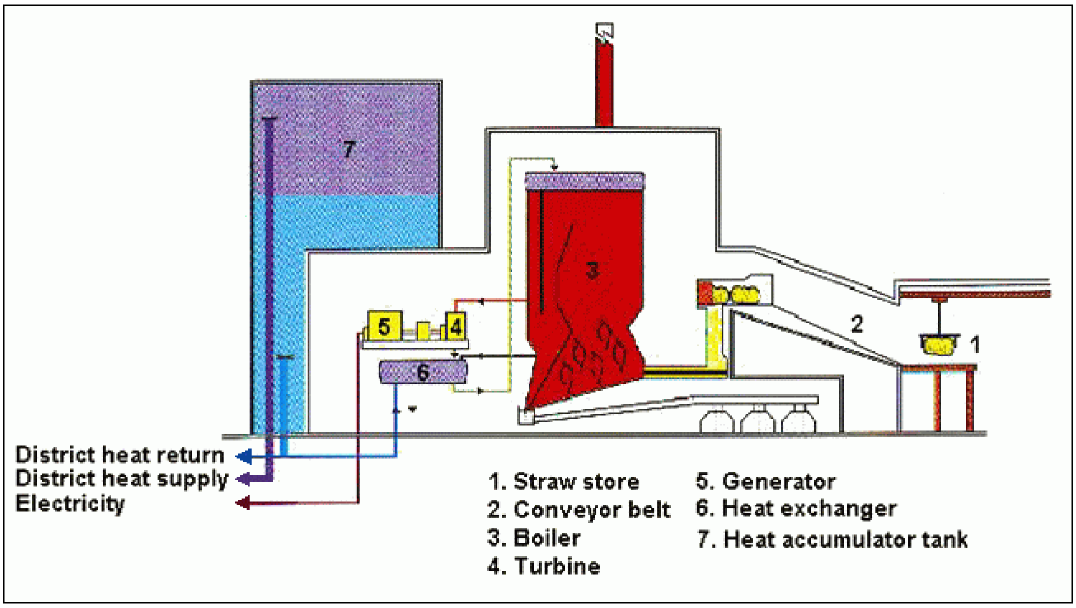


Figure 5.9: Straw firing combustion plant

Achieved environmental benefits: The advantage of a CHP plant is that the energy in the fuel is better used. The plant uses 92 % of the energy, of which 32 % is based solely on the production of electricity. The firing of straw is considered CO_2 neutral. Danish farmers supply the straw and the ash is returned to the fields as fertiliser. The plant is equipped with dust abatement: this involves a bag filter using pulse jet cleaning, and a bag material of Nomex filter lined with Teflon fibres. It is possible to remove 99.9 % of the dust. Part of the dust/fly ash is then mixed with bottom ash and used as fertiliser, and the remaining part of the fly ash is disposed of because of the presence of cadmium. The plant is not equipped with NO_X or SO_2 abatement equipment.

Generally, it should be noticed that the variation of the SO_2 in emissions from straw-fired combustion plants is from 50 to 300 mg/Nm^3 (daily mean value), with a typical yearly mean value of 150 mg/Nm^3. The variation in the HCl emissions is from 50 to 300 mg/Nm^3 (daily mean value) with a typical yearly mean value of 100 mg/Nm^3. The emission of dioxin/furan (PCDD/DF) is less than 0.1 ng I-TEQ/Nm^3. The NO_X emissions are around 300 – 400 mg/Nm^3 (dry, 6 % O_2, hourly mean values) for straw-fired CHP plants. Because of the aggressive environment, it is considered economically feasible to apply an SCR installation and because of the type of firing, i.e. grate-fired, low NO_X burners are not feasible.

Operational data: In 2000, 27258 MWh$_e$ and 267732 GJ were produced and 433350 GJ straw was consumed. In Table 5.10, the data is listed together with data from two other straw-fired plants. It should however be noted that part of the production at the plant in Masnedø (Denmark), is based on wood chips. The emissions are not measured on a continuous basis, therefore the emission levels referred to in Table 5.10 are based on test samples.

	Units	**Plant A**	**Plant B**	**Plant C**
Started up	year	1989	1996	2000
Electrical power (net)	MW	5.0	8.3	10.6
Heat output	MJ/s	13.0	20.8	20.3
Steam				
Pressure	bar	67	92	93
Temperature	°C	450	522	542
Max. flow	tonnes/h	26.0	43.2	43.2
District heating water				
Storage tank	m^3	3200	5000	5600
Flue-gas				
Flow, max	kg/s	9.9	14.0	14.0
Temperature	°C	120	120	130
Straw				
Storage	tonnes	350	1000	1000
Consumption	tonnes/year	25000	40000	40000
Water content	%	10 - 25	max 25	Max 25
Installations				
Filter type		Bag filter	Elec. Filter	Bag filter
Firing system		Cigar burner	Shredded/ Stoker	Shredded/stoker
Emissions at 6 % O_2				
CO	mg/Nm^3	190 - 314	72 - 238	50 - 214
Dust	mg/Nm^3	14	21 - 28	0.7 - 2
NO_X	mg/Nm^3	530 - 644	327 - 443	248 - 319
SO_2	mg/Nm^3	155 - 168	131 - 166	160 - 190
Efficiency				
Efficiency$_{el}$	%	25	28	32
Efficiency total	%	86	91	92

Table 5.10: Data for three Danish straw-fired plants

Economics:

Data	**Unit**	**Plant A**	**Plant B**	**Plant C**
Boiler plant costs	DKK	100 million	240 million	240 million
Specific 1995- price	DKK/MW_e	23 million	28 million	23 million

Table 5.11: Costs of the three Danish straw-fired plants

Reference literature: [144, CBT, 1998], [145, Sander, 2000].

EXAMPLE 5.2.3.3 INDUSTRIAL SPREADER-STOKER CHP PLANT WITH SNCR AND FABRIC FILTER

Description: The spreader-stoker technique described here will be illustrated with three examples of almost identical chip board plants operated in France and Germany. In Table 5.12 all substantial parameters for the three plants are summarised. These plants are mainly used for the valorisation of wood residues and wood dust and provide the heat demand for chip board production. Therefore, a high and constant energy demand is ensured.

	Plant A	**Plant B**	**Plant C**
Year of implementation	1994	1997	2000
Rated thermal input (MW)	50	73.5	57.7 (grate firing, maximal 28 MW of it delivered by wood dust burners) + 6.7 (Thermo oil boilers: wood dust + extra light fuel oil)
Gross electric power (MW)		16.6 (maximal) 11 (annual mean)	13.3
Availability	Operational life cycle times >5000 h, availability 99.8 %	Operational life cycle times >5000 h	Operational life cycle times >5000 h
Maximal rated thermal input (MW)		63	35 + 6.7
Overall gross energy efficiency (%)		96.6 max.	c. 85 %
Main steam parameters		450 °C, 67 bar	455 °C, 70 bar
Main fuels	Production residues, waste wood, railway sleepers, etc.		

Table 5.12: Technical data for the three example plants

The following description of the technique refers to all three example plants, unless otherwise specified. The spreader-stoker technique is a combustion on an air-cooled travelling-grate stoker, the fuel being evenly spread on the grate by an injection-stoker, which throws the particles in. While the bigger pieces are evenly burned in a fixed bed combustion on the grate, the smaller particles are ignited in a fluidised bed separately above the combustion chamber (this applies to about 50 % of the fuel). This provides good conditions for a high combustion efficiency and residence times of four to five seconds result. Therefore, the air rate can be minimised (O_2 content in the raw gas of less than 3 %), which also reduces NO_X emissions.

The formation of a fluidised bed is possible because the velocity of the flue-gas is similar to the velocity occurring in fluidised bed combustions. The formation of a fluidised bed also means a staging of the fuel, supporting low NO_X combustion. Also the low maximal temperature of 1250 °C supports this effect.

Half of the air is injected by a jet tray, the other half is blown in at a high pressure through nozzles on the walls. Thus, it is a staged combustion with under stoichiometric conditions at the bottom and high turbulence at the same time.

The spreader-stoker plant realises an intensive combustion at high temperatures with a broad spectrum of fuels. The optimised temperature can be sustained by controlled injection of recirculated flue-gas. The ideal adiabatic temperature of the combustion chamber for simultaneous minimisation of CO and NO_X is 1300 to 1400 °C.

The temperature achieved in reality is about 150 °C below this. The lining of the walls with masonry for thermal isolation is not necessary, which also prevents the formation of boiler slag and, therefore, results in high operational life cycle times (>5000 h).

For the combustion of abrasive dust, there are four pulverised-fuel burners installed in plant C. The maximal rated thermal input is 28 MW and contains plug nozzle burners. These can also be driven by extra light fuel oil.

The heat is used mainly for the drying of splints. In plant B, up to 26 t/h are dried in rotary dryers, which means that the moistness is reduced from 60 to 100 % to about 2 %. The drying is realised indirectly by heated tube bundles of 180 °C. Further on, the heat is conducted by thermo oil at 240 °C to a heated end-squeezer in order to dry and consolidate the chip boards. In this process, a mix of air, water and products of degasification occurs, which is returned as combustion air and thus delivers 30 % of the air needed in the boiler. This design provides high energy efficiency and after-burning of the emissions arising from the drying. The exhaust air from the drying of chipping particles is also applied partly to the boiler. All plants are equipped with bag filters to meet the required limit values for particle emissions.

Plant C is fitted with a supplementary SNCR installation. Ammonium hydroxide with 25 mass- % of NH_3 is used as the reducing agent. This is stored aboveground in a tank of stainless steel. Furthermore, plant C is equipped with an adsorption process as a separator. This combined duct sorbent injection (dry adsorption) requires the injection of a ground mix of active carbon/coke and hydrated lime (= adsorbent) in the flue-gas flow which is then separated from it by a fabric filter. During this time, dust, HCl, HF, SO_x, heavy metals, and PCDD/F are adsorbed and thus separated from the flue-gas. Therefore, all types of wood waste can be fired in this plant.

Achieved environmental benefit: By using wood as a biomass fuel, one can achieve an almost neutral CO_2 balance. With the simultaneous utilisation of power and heat, the overall energy efficiency can achieve about 85 to 96.6 %. Only small amounts of waste water arise, coming from the waste water treatment of the water-steam circuit.

At the same time, combustion technology allows low emissions of NO_X and CO to be achieved in the raw gas. Combined with reduction measures like bag filters, SNCR and duct sorption plants, very low concentrations can be achieved for all types of pollutants.

Applicability: The spreader-stoker technique is suitable for a wide range of fuels, exceeds the performance of fluidised bed technology, and is especially used with fuels with highly heterogeneous particle sizes and contaminants (such as metal pieces).

The plants described here are especially designed for applications in the chip board and MDF board industry and are economically viable because of the energetic valorisation of the wood residues and because of the continuous demand for heat. For locations with similar characteristics, the application of this technology is also reasonable.

Cross-media aspects: High amounts of ash result from these plants. Furthermore, water treatment produces waste water. Also, the adsorbent used in the flue-gas cleaning plants has to be deposited.

Operational data: Atmospheric emissions accruing from plant B are shown in Table 5.13.

	Monitoring	**Statistics**	**Measured value (at 11 % O_2)**
Dust (mg/Nm^3)	Continuous	Daily mean value	3.4 – 4.3**
CO (mg/Nm^3)	Continuous	Daily mean value	46.7 – 58.3**
NO_X (mg/Nm^3)	Continuous	Daily mean value	183.9 – 190.7**
C total (mg/Nm^3)	Continuous	Daily mean value	1.1 – 1.2**
HCl (mg/Nm^3)	Continuous	Daily mean value	8**
Hg (gas) (mg/Nm^3)	Continuous	Daily mean value out of 2 hour mean values	0.001**
Dioxins/furans (ng TEQ/Nm^3)	Continuous sampling, single values	Mean of 20 days	0.0019
PAH (mg/Nm^3)	Continuous sampling, single values	Mean of 4 days	0.0003
Cd (mg/Nm^3)	Continuous sampling, single values	Mean of 4 days	0.0005
As/Pb/Cu/Ni/Sn (in the particles) (mg/Nm^3)	Continuous sampling, single values	Mean of 4 days	0.053
As (mg/Nm^3)	Continuous sampling, single values	Mean of 4 days	0.0005
Notes: *value for precaution **intervals based on three daily mean values in January 2001			

Table 5.13: Measured atmospheric emissions in 2000/2001

For plant C, a consumption of 120000 t/yr wood is estimated. For plant B, the different types of fuels are used in the amounts listed in Table 5.14.

Fuel	**Wood dust**	**Cardboard pieces**	**Wood residues out of packaging/loading**	**Special fuels (railway sleepers)**	**Timber**	**Biomass pellets**
Contribution to the total fuel consumption	30 %	10 %	10 %	Max. 20 %	Varying	Varying, approx. 15000 t/yr

Table 5.14: Contribution of the different fuel types to the total fuel consumption in plant B

The size of the pieces should be below 100 mm. However, a few pieces can be up to 250 mm. This limit is set by the transport devices, e.g. screw conveyors. For the preparation of all fuels by a hacker, costs of EUR 0.5/t were given for a plant of 60 MW. The accruing boiler ash and fly ash are used in the construction industry.

Economics: The investment for plant B amounted to EUR 36 million.

Driving force for the implementation: The possibility to re-use the by-products and the need to deposit the wood residues in an economically reasonable way.

Reference literature: [98, DFIU, 2001], [101, Vaget, 2001], [102, Fischer, 2000], [78, Finkeldei, 2000].

5.3 Current consumption and emission levels

5.3.1 Mass stream overview

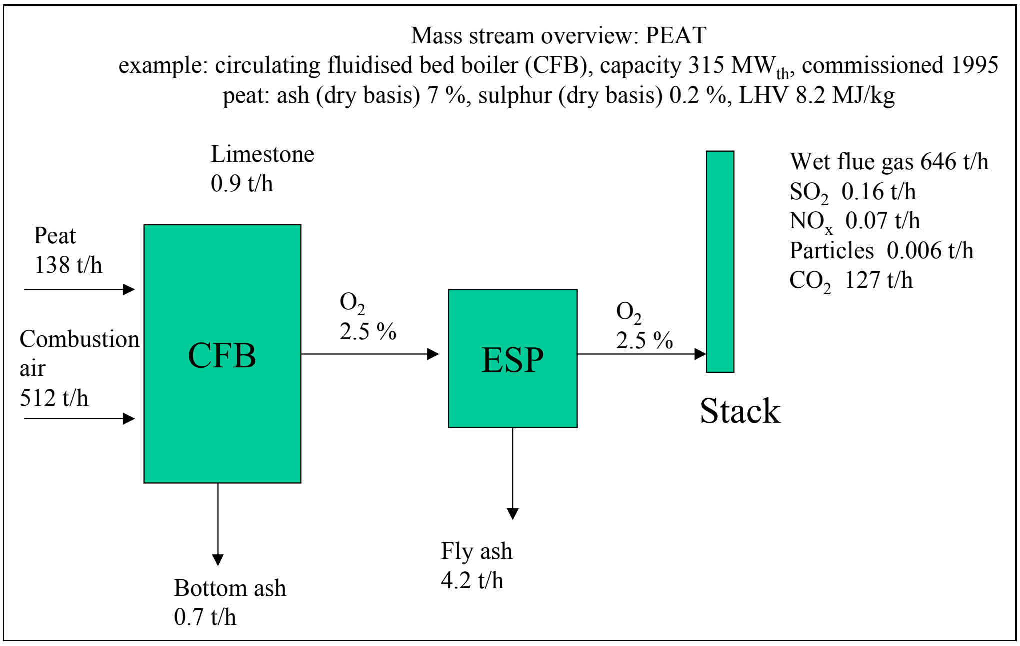


Figure 5.10: Example of the mass stream of a peat-fired CFBC boiler [58, Eurelectric, 2001]

5.3.2 Overview of biomass and peat used in large combustion plants

5.3.2.1 Biomass

Biomass is defined in the LCP Directive as products consisting of the whole or part of any vegetable matter from agriculture or forestry which can be used as a fuel for the purpose of recovering its energy content and the following biomass is used as a fuel:

- vegetable residues from agriculture and forestry
- vegetable residues from the food processing industry
- vegetable residues from virgin pulp production and from the production of paper from pulp
- cork waste
- wood with the exception of wood waste which may contain halogenated organic compounds or heavy metals as a result of treatment with preservatives or coating, and which includes in particular such wood waste originating from construction and demolition waste.

The above listed fuels are often also classified as ‘wastes’ and the implications of the Waste Incineration Directive (WID) need to be taken into account. This is particularly important for certain wastes which are only excluded from the WID by certain criteria. Of greatest importance are the exceptions for vegetable residues from non virgin pulp production and the use of contaminated wood wastes from construction/demolition. The WID applies to the co-combustion of such wastes and operators/regulators must ensure that such consideration are fully recognised in any permit. For the co-combustion of waste, reference is given to Chapter 8 of this document.

Biomass such as bark, wood chips, cardboard, fibre board or other residues from pulp or sawmills contains high amounts of water and is burned on specially designed sloping grates (an older technique), boilers equipped with a spreader-stoker system or in fluidised beds. Although the chemical compositions of the bark and wood of different species are slightly different, and the amount of dirt and soil affects the ash content and composition, the biomass derived from forestry and forest industries has, in broad terms, certain common qualities as a fuel.

The sulphur content is small and the ash content moderate (Table 5.15). Burned together with peat for instance, wood ash can react with sulphur from the peat and act as a desulphurising agent. On closer examination, the differences in fuel moisture and consistency are considerable, and these affect the fuel handling and combustion properties. All these details need to be taken into account when determining techniques for their storage, transportation, combustion and possible flue-gas treatment.

	Logging residue chips	Whole tree chips	Log chips	Stump chips	Softwood bark	Birch bark	Wood residue chips	Saw residue chips	Sawdust	Cutter chips	Grinding dust	Pellets
Moisture content, wt-% (fresh chips)	50 – 60	45 – 55	40 – 55	30 – 50	50 – 65	45 – 55	10 - 50	45 – 60	45 – 60	5 – 15	5 – 15	10
Net calorific value in dry matter MJ/kg	18.5 – 20	18.5 – 20	18.5 – 20	18.5 – 20	18.5 – 20	21 – 23	18.5 – 20	18.5 – 20	19 – 19.2	19 – 19.2	19 – 19.2	19.2
Net calorific value as received MJ/kg	6 – 9	6 – 9	6 – 10	6 – 11	6 – 9	7 – 11	6 – 15	6 – 10	6 – 10	13 – 16	15 – 17	16.8
Bulk density as received, kg/loose m^3	150 – 300	250 – 350	250 – 350	200 – 300	250 – 350	300 – 400	150 – 300	250 – 350	250 – 350	80 – 120	100 – 150	500 – 750
Energy density, MWh/m^3 of bulk volume	0.7 – 0.9	0.7 – 0.9	0.7 – 0.9	0.8 – 1.0	0.5 – 0.7	0.6 – 0.8	0.7 – 0.9	0.5 – 0.8	0.45 – 0.7	0.45 – 0.55	0.5 – 0.65	2.3
Ash content in dry matter, wt-%	1 – 3	1 – 2	0.5 – 2	1 – 3	1 – 3	1 – 3	0.4 – 1	0.5 – 2	0.4 – 0.5	0.4 – 0.5	0.4 – 0.8	6.2 – 6.4
Hydrogen content in dry matter, wt-%	6 – 6.2	5.4 – 6	5.4 – 6	5.4 – 6	5.7 – 5.9	6.2 – 6.8	5.4 – 6.4	5.4 – 6.4	6.2 – 6.4	6.2 – 6.4	6.2 – 6.4	6.2 – 6.4
Sulphur content in dry matter (S), wt-%	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
Nitrogen content in dry matter (N), wt-%	0.3 – 0.5	0.3 – 0.5	0.3 – 0.5	0.3 – 0.5	0.3 – 0.5	0.5 – 0.8	0.1 – 0.5	0.1 – 0.5	0.1 – 0.5	0.1 – 0.5	0.1 – 0.5	0.1 – 0.5

Table 5.15: Average properties of different types of solid wood fuels
[60, Alakangas, 1998]

An emerging class of biomass fuel used by pulp and paper mills and at heating plants is forestry residue, i.e. small trees, treetops and branches of trees, which are collected specifically for fuel in connection with other forestry operations. Experimentation has also been going on for over two decades with the growing of various Salix species specifically for fuel. The economics of these fuels are not very good, mostly due to the costs of collection and transport, and consequently only insignificant amounts are currently used in LCPs so far.

The small amounts of forestry residue actually used are usually co-fired with other fuels at existing installations, particularly at peat or bark residue-fired FBC plants. However, not all forestry biomass is automatically suitable for burning, even at FBCs designed for peat or bark.

Straw is a residue from the agricultural production of grain, and indeed most of the annual straw production is consumed within the agricultural sector. Surplus straw is utilised for energy production in either small district heat producing boilers or larger CHP plants of up to 40 MW_e. Straw is converted to power and heat in conventional power plants, but many technical issues have to be considered due to the special characteristics of straw. A particular concern is that the relatively high chlorine content of straw may cause serious corrosion on the superheater surface.

Other biomass fuels used are, e.g. olive stones, aspen bark, rubber trees and reed canary grass. All these fuels have a relatively high alkali (Na, K) content.

5.3.2.2 Peat

Peat is significant as a fuel for LCPs in Ireland and Finland. Peat, as a fuel in Finland, was quite insignificant at the beginning of the 1970s, with a 0.1 % share of the primary energy input, but with rising import fuel prices, peat has gained a strong position, with a 6 % share of the primary energy input and a 16 % share of LCP fuels in 1998. In Finland, peat consumption at large combustion plants was 1.81 Mt, i.e. 16 % of the total LCP fuel used. In Ireland, 2.9 Mt of peat accounted for about 11 % of fuel used in a thermal power plant in 2001.

Peat bogs deep and large enough for economic peat production occur in all parts of Finland, and only a small fraction of them are being exploited, because no demand for peat can be found at an economical distance. Peat is a relatively clean fuel characterised by low ash and sulphur contents, typically around 5 % and 0.5 % respectively of dry substances. Peat has a high volatile content and is very reactive if its moisture content falls below 40 % (see Table 5.16). For large-scale use, it is typically used as milled peat, produced during May to August and dried to 45 to 60 % moisture by the sun and wind on the production site and subsequently stored next to the production site. With respect to the high moisture content, peat is comparable to lignite, while, in terms of dry substance, it is closer to biomass than to lignite.

	Steam coal 1)	**Milled peat**	**Bark**	**Wood** 2)	**Heavy fuel oil**	**Natural gas**
Moisture %	10	50	55	40	0.5	<0.1
Ash % of dry matter	14	3 – 6	2 – 3	0.4	<1	0.0
Volatile matter in dry fuel %	25 – 35		70 – 80	80 – 90		
Sulphur of dry substance %	<1	0.5	<0.2	0.05	<1	0.0
Fuel nitrogen compounds %	1	1.7	0.5	0.5	0.3	0.05
Cl (mg/MJ fuel LHV) 3)	<0.1		<0.03	<0.01		
As (mg/MJ fuel LHV) 3)	0.14	0.1	0.01	0.01	0.04	
Cd (mg/MJ fuel LHV) 3)	0.15	0.004	0.015	0.01 – 1.1	-	-
Hg (mg/MJ fuel LHV) 3)	0.003	0.003	0.1	0.001 – 0.009	<0.0001	-
Ni (mg/MJ fuel LHV) 3)	0.4	0.3	0.04	0.03	0.9	-
Pb (mg/MJ fuel LHV) 3)	0.5	0.3	0.15	0.1 - 0.7	0.06	-
Fuel bulk density (kg/Nm^3)	1350	350	350	200	987	
Fuel bulk LHV (GJ/Nm^3)	34.3	2.9	2.5	2.1	40	
LHV of dry substance (MJ/kg)	28.7	20	19	19	40.2	48
Lower heating value (LHV) (MJ/kg)	25.5	8.4	7.2	10.4	40.1	48
Stoichiometric flue-gas (Nm^3/MJ)	0.278	0.383	0.435	0.357	0.277	0.297
Stoichiometric dry flue-gas (Nm^3/MJ)	0.253	0.281	0.291	0.259	0.246	0.239
CO_2 (gCO_2/kWh)	476.1	658.8			402.5	172.8
CO_2 (gCO_2/MJ) (LHV)	90	106 – 118	113	100	76	54
Power genererated. heat rate (kWh/kWh) (LHV)	2.3	2.3 – 2.7			2.3	1.8
Emitted CO_2 per electric kWh (g/kWh)	207	244			175	96

LHV – lower heating value
Notes:
1) Polish export coal
2) wood chips
3) order of magnitude figures only.

Table 5.16: Comparison of milled peat to other fossil fuels normally used in LCPs [59, Finnish LCP WG, 2000]

Peat is a voluminous fuel with a low calorific value. It can, therefore, rarely be economically transported over distances of more than c. 100 km. As a result, the number of plants burning peat mainly consists of small-scale local co-generation or heat only plants for small to medium district heating systems. A great number of those plants in Finland are below 50 MW fuel input and, as such, do not qualify as large combustion plants. However, in energy terms, the largest consumer of peat fuel consists of the LCP co-generation and heating plants in the district heating systems of the (mostly inland) cities with populations of 50000 to 200000. Overall, the district heating sector consumed 0.86 Mt of peat in 1998, industrial co-generation and heating plants consumed 0.58 Mt, and the two peat-fired condensing power plants with 155 and 120 MW$_e$ outputs consumed 0.40 Mt.

5.3.3 The efficiency of biomass and peat fired combustion plants

As mentioned earlier, many peat and biomass fired power plants are CHP plants. The co-generation of electricity and heat enables the energy contained in the fuel to be used to its full advantage, and the plant efficiency is thus high (85 – 90 %). The energy efficiency (fuel efficiency) level for co-generation plants is difficult to determine on a general basis. The efficiency is highly site-specific important issues being the heat load and changes in the heat load, price level and the need for electricity in the market, applied technology, etc. The co-generation of heat and power should be considered as a technical option whenever economically feasible, i.e. whenever the local heat demand is high enough to warrant the construction of the more expensive co-generation plant instead of the simpler heat only plant.

The biomass or peat fired condensing power plants based on fluidised bed combustion are usually smaller in size than the coal-fired plants and the steam pressure and temperature are much lower than with the advanced coal-fired power plants. The heat rate levels for biomass and peat fired FBC power plants are around 3.3 – 3.6 (power plant efficiency 28 – 30 %). But only a few plants operate with these fuels for power generation only. Concerning pulverised peat firing, efficiency levels at 38 – 39 % have been reached in a pulverised peat boiler in Finland.

5.3.4 Emissions to air

5.3.4.1 Emissions to air from biomass fired combustion plants

The emissions of biomass plants depend mainly on the composition of the fuel and the flue-gas treatment but (NO_X excluded) not on the size or combustion technology. NO_X emissions also depend on the combustion characteristics and the presence of a DENOX system. Eurelectric has reported NO_X emissions of between 300 – 400 mg/Nm^3, dust levels of between 10 – 50 mg/Nm^3 and, in addition for peat firing, an SO_2 level of 200 – 400 mg/Nm^3 for new peat and biomass fired plants.

Capacity (MW_{th})	Comb. Tech.	Emission reduction measures	Emissions to air (mg/Nm³)							Remarks
			SO_2	NO_X	Dust	CO	HF	HCl	NH_3	
50 – 100	GF (spreader-stoker)	SNCR/ FGD(ds)/FF		179 – 191	0.7 – 4.6	39 – 75		7.7 – 9.4		Dioxins 0.0014 ngTE/Nm³ PAH 0.003 mg/Nm³ Cd 0.005 mg/Nm³ As/PB/Cu/Ni/Zn 0.053 mg/Nm³ Total Carbon 1.1 – 1.4 mg/Nm³
	AFBC	FF	2.3 – 2.9	164 – 339	2.2 – 4	147 – 178	0.04 – 0.1	7.3 – 8.8		Dioxin 0.006 – 0.013 ngTE/Nm³ Cd+Tl 0.003 – 0.004 mg/Nm³ Hg 0.001 mg/Nm³
100 – 300	AFBC	FF	10	90	10	150		5		Dioxin 0.008 ngTE/Nm³ PAH 0.1 mg/Nm³ PCB 11mg/Nm³

Notes:
GF (Grate firing) **PC (**Pulverised coal combustion) **AFBC** (Atmospheric fluidised bed combustion) **PFBC** (Pressurised fluidised bed combustion)
FGD(w) (Wet flue-gas desulphurisation) **FGD(sd)** (Flue-gas desulphurisation by using a spray dryer)**FGD(ds)** (Flue-gas desulphurisation by dry sorbent injection)
ESP (Electrostatic precipitator) **FF** (Fabric filter) **Pm(..)** (Primary measures to reduce $NO_{X)}$
SCR (Selective catalytic reduction of NO_X) **SNCR** (Selective non-catalytic reduction of NO_X)

Table 5.17: Emissions to air from biomass-fired combustion plants (data represents specific biomass fuel and may not necessarily be representative)

Capacity (MW_{th})	Comb Tech.	Emission reduction measures	Electrical efficiency (%)	Fuel efficiency (%)	Specific emissions to air (mg/MJ)					
					SO_2	NO_X	Dust	CO	HF	HCl
50 – 100	GF									
	AFBC									
100 – 300	AFBC	Pm (staged air)/ESP			6	57	9			
>300										

Notes:
GF (Grate firing) **PC (**Pulverised coal combustion) **AFBC** (Atmospheric fluidised bed combustion) **PFBC** (Pressurised fluidised bed combustion)
FGD(w) (Wet flue-gas desulphurisation) **FGD(sd)** (Flue-gas desulphurisation by using a spray dryer) **FGD(ds)** (Flue-gas desulphurisation by dry sorbent injection) **ESP (**Electrostatic precipitator) **FF** (Fabric filter) **Pm(..)** (Primary measures to reduce $NO_{X)}$
SCR (Selective catalytic reduction of NO_X) **SNCR** (Selective non-catalytic reduction of NO_X)

Table 5.18: Specific missions to air from biomass-fired combustion plants

5.3.4.2 Emissions to air from peat-fired combustion plants

Capacity (MW_{th})	Comb. Tech.	Emission reduction measures	Emissions to air (mg/Nm^3)							Remarks
			SO_2	NO_X	Dust	CO	HF	HCl	NH_3	
50 – 100	GF									
	PC									
	AFBC									
100 – 300	PC									
	AFBC	FF	10	90	10	150		5		Fuel (50 % peat and 50 % bark) Dioxin 0.008 $ngTE/Nm^3$ PAH 0.1 mg/Nm^3
	AFBC	ESP	330 – 450	300 – 350						
>300	PC									
	AFBC		540 – 620	900 – 1000						

Notes:
GF (Grate firing) **PC** (Pulverised coal combustion) **AFBC** (Atmospheric fluidised bed combustion) **PFBC** (Pressurised fluidised bed combustion)
FGD(w) (Wet flue-gas desulphurisation) **FGD(sd)** (Flue-gas desulphurisation by using a spray dryer) **FGD(ds)** (Flue-gas desulphurisation by dry sorbent injection) **ESP** (Electrostatic precipitator) **FF** (Fabric filter) **Pm(..)** (Primary measures to reduce NO_X)
SCR (Selective catalytic reduction of NO_X) **SNCR** (Selective non-catalytic reduction of NO_X)

Table 5.19: Emissions to air from peat-fired combustion plants

Capacity (MW_{th})	Comb Tech.	Emission reduction measures	Electrical efficiency (%)	Fuel efficiency (%)	Specific emissions to air (mg/MJ)					
					SO_2	NO_X	Dust	CO	HF	HCl
50 – 100	GF									
	PP									
	AFBC									
100 – 300	PP									
	AFBC	Pm (staged air) /limestone/ESP			136	99	2			
>300	PP									
	AFBC									

Notes:
GF (Grate firing) PC (Pulverised coal combustion) AFBC (Atmospheric fluidised bed combustion) PFBC (Pressurised fluidised bed combustion)
FGD(w) (Wet flue-gas desulphurisation) FGD(sd) (Flue-gas desulphurisation by using a spray dryer) FGD(ds) (Flue-gas desulphurisation by dry sorbent injection) ESP (Electrostatic precipitator) FF (Fabric filter) Pm(..) (Primary measures to reduce NOX)
SCR (Selective catalytic reduction of NOX) SNCR (Selective non-catalytic reduction of NOX)

Table 5.20: Specific emissions to air from peat-fired combustion plants

5.3.5 Combustion and other plant residues

Properties of biomass and peat ashes

The mineral content of peat ash is very similar to the constituents of sandy soil. Due to the limestone base on which the bogs were formed, peat ash in Ireland typically contains 25 – 55 % CaO when used as a fuel. The combustion technique applied has an effect on the character of ash produced, although the quality of peat is the determining factor.

Peat ash is formed from mineral matter in peat. The bottom ash from fluidised bed combustion also contains bed sand from the combustion chamber.

Peat fly ash is a fine powder consisting mainly of particles of variable silica, alumina and iron oxide (65 – 75 %). Other major species are compounds of the alkali and earth alkali metals (10 – 55 %) and unburned peat particles (0 – 5 %). Due to the limestone base underlying the peat bogs, peat ash in Ireland typically contains 25 – 55 % CaO. The fly ash also contains trace elements, i.e. metals.

Ash from combustion with limestone injection

The ash from fluidised bed combustion with limestone injection contains the end-product of the desulphurisation reaction, unreacted calcium oxide and limestone (about 15 wt-%).

Solubility of ash

The solubility of trace elements in fly ash is an important factor when assessing the potential environmental impacts. The alkali and earth alkali metals (e.g. sodium, potassium) and other mineral elements like boron and chlorides are the most soluble compounds. Trace metals in ash are poorly soluble in water.

5.3.6 Potential sources of noise emission

Noise during operation is typically industrial steady noise. Major noise sources at the peat/biomass fired power plant are turbines, generators, boilers, pumps, fans and boosters and peat/biomass handling operations. Most of these are located inside the buildings, so noise is attenuated by wall structures. Operational noise can be restricted by structural means, for instance by encasing or by using silencers.

Special care has to be taken when cutting straw needed for co-firing with coal in pulverised fuel boilers. A good way of cutting straw are using hammer-mills (which have a high noise level). Special attention has also to be paid to subsequent pneumatic transport to the burner.

5.4 Techniques to consider in the determination of BAT for the combustion of biomass and peat

This section presents techniques that have been considered in the determination of BAT for the preventing or reducing emissions and for increasing the thermal efficiency. They are all currently commercially available. In this section, techniques to be considered have only been described in a general way, but for most of the techniques, more detailed descriptions are presented in Chapter 3 and for some techniques examples are given in Section 5.2 to demonstrate in detail the environmental performance of these techniques when applied in a real situation. In principle, the general techniques described in Chapter 3 also apply to a large extent to the combustion of biomass and peat and should in general also be seen as techniques to consider in the determination of BAT. For more detailed descriptions, refer to Chapter 3.

To avoid duplication throughout this document, refer to Environmental Management Systems (EMS) in Section 3.15.

5.4.1 Techniques for the unloading, storage and handling of fuel

Technique	Environmental benefit	Applicability		Operational experience	Cross- media effects	Economics	Remarks
		New plants	Retrofitable				
Transport and handling of biomass and peat							
Closed transfer systems with fabric filters	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	
Open conveyors with wind shields	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	Open conveyor belts can only be considered for lumpy material (wood pieces)
Unloading of biomass and peat in enclosed buildings equipped with a bag filter for dust abatement	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	
Cleaning devices for conveyor belts	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	
Storage of biomass, peat and additives							
Storage of fine dusty fuel material in enclosed areas or silos	Reduction of fine particulates	Possible	Possible	High	None	Not available	
Separate storage of biomass fuels of different qualities	Stable combustion conditions	Possible	Possible	High	None	Not available	
Enclosed storage of lime/limestone in silos with dust abatement	Reduction of fine particulates	Possible	Possible	High	None	Not available	
Sealed surfaces with drainage systems	Prevention of soil and groundwater contamination	Possible	Possible	High	None	Extra cost for waste water treatment	Collected drainage water needs to be treated in a settling pond
Wind shields for open storage of lumpy wood, etc.	Reduction of fugitive dust emissions	Possible	Possible	High	No	Not available	
Storage of ammonia as ammonia-water solution	Higher safety	Possible	Possible	High	Less risk than storage of pressurised liquid ammonia	Not available	

Table 5.21: Techniques for the unloading, storage and handling of fuel

5.4.2 Techniques for fuel pretreatment

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Fuel drying	Increased efficiency	Possible	Possible	Limited experience	Increased efficiency	Additional cost of dryers	Low value heat can be generated from power processes to increase the fuel energy. Steam dryers are most efficient
Biomass gasification	Increased plant efficiency and lower emission levels Gas can be used as reburning fuel to reduce emissions of NO_X	Possible but until now only applied in demonstration and pilot plants	Possible but until now only applied in demonstration and pilot plants	Limited experience		Expensive in small scale	In the medium term, gasification has the potential to constitute a viable alternative to normal combustion, particularly in view of the expected electrical efficiencies of 51 – 55 %
Bark pressing	Increased combustion efficiency	Possible	Possible	High	High BOD releases to water and high energy use and maintenance		

Table 5.22: Techniques for fuel pretreatment

5.4.3 Combustion techniques

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Co-generation of heat and power (CHP)	Increased fuel efficiency, less fuel consumption	Possible	Possible	High		Not available	Peat and biomass are nowadays mainly used in combined heat and power production, due to the high fuel efficiency (75 – 90 %)
Grate-firing	Variable for different bio-fuels such as straw	Possible	Possible	High	None	Not available	
Spreader-stoker travelling grate	High fuel burn-out with low emission levels (i.e. of NO_X)	Possible	Possible	Practised in new plants	None	Not available	
Fluidised bed combustion (BFBC and CFBC)	High fuel burn-out with low emission levels (i.e. of NO_X)	Possible	Possible	Practised in new plants	None	Not available	Main combustion technique for biomass and peat today
Pulverised peat combustion	good exergetic efficiency	Possible	Possible	High		Not available	

Table 5.23: Combustion techniques

5.4.4 Techniques to increase the efficiency

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Co-generation of heat and power (CHP)	Increased efficiency	Possible	Possible	High		Not available	Peat and biomass are nowadays mainly used in combined heat and power production due to the high fuel efficiency (75 – 90 %) compared to the electric efficiency, which is normally only around 25 %.
Change of turbine blades	Increased efficiency	Possible	Possible	High	None	Not available	Steam turbine blades can be changed to three-dimensional blades during regular maintenance intervals.
Regenerative feed-water heating	Increased efficiency	Possible	very limited	Practised in new plants and some existing ones	None	Not available	Regenerative feed-water heating retrofit is also possible in special cases
Bark pressing	Increased combustion efficiency	Possible	Possible	High	High BOD releases to water and high energy use and maintenance		
Fuel drying	Increased efficiency, expansion for potential biomass fuels, safer use	Possible	Possible	Limited			New technical alternatives are under development. The implementation of drying systems can save 10 % of fuel consumption with wet fuels like peat or energy wood. Many alternative technologies are commercially available. Wet biomasses are safe to harvest, store and transport. So many benefits are achieved if fuel can be dried just before combustion.

Table 5.24: Techniques to increase the efficiency

5.4.5 Techniques for the prevention and control of dust and heavy metal emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Fabric Filter	Reduction of particulate emissions particularly fine dust (PM 2.5 and PM 10)	Possible	Possible	High	None	The investment cost for a new fabric filter is less than that for an ESP, but operating costs are higher.	
ESP	Reduction of particulate emissions	Possible	Possible	High	None	Not available	

Table 5.25: Techniques for the prevention and control of dust and heavy metal emissions

5.4.6 Techniques for the prevention and control of SO_2 emissions from peat-fired combustion plants

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Primary measures							
Co-combustion of biomass and peat	Reduction of SO_2 and CO_2 emissions at the source	Possible	Possible	High		Depends on type fuel	
Injection of limestone in peat-fired FBC-boilers (BFBC and CFBC)	Reduction of SO_2 and NO_X emissions	Possible	Possible	High	Higher emissions of N_2O	Cost figures are presented in example 5.2.1.1.	
Secondary measures							
Spray dry scrubber	Reduction of SO_2, HF, HCl, dust,	Possible	Possible	High	Residues that needs to be landfilled	Cost figures are presented in example 5.2.1.1.	
Calcium hydroxide injection in dry form before the baghouse or ESP	Reduction of SO_2, HF, HCl, dust and Hg emissions (if combined with activated carbon)	Possible	Possible	High	The low levels of SO_2 means that the utilisation opportunities for the ash will be lower. High Ca/S ratios result in a large addition to the amount of by-product collected by ESPs and that the quality of the by-product is dramatically changed.	Not available	Furnace injection only for BFBC and CFBC plants. Significant fouling was reported in the BFB plant

Table 5.26: Techniques for the prevention and control of SO_2 emissions from peat-fired combustion plants

5.4.7 Techniques for the prevention and control of NO_X and N_2O emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Primary measures							
Low excess air	Reduction of NO_X, CO, and N_2O emissions, also an increased efficiency.	Possible	Possible	High	Reduction of NO_X emissions leads to higher unburned carbon-in-ash	Plant specific	
Staged combustion	Reduction of NO_X	Possible	Possible	High		Plant specific	
Air staging (OFA)	Reduction of NO_X	Possible	Possible	High	Leads to higher unburned carbon-in-ash	Plant specific	
Flue-gas recirculation	Reduction of NO_X	Possible	Possible	High		Plant specific	
Low NO_X burners	Reduction of NO_X	Possible	Possible	High	Leads to higher unburned carbon-in-ash	Not available	Standard low NO_x burners are not available for peat
Secondary measures							
Selective Non Catalytic Reduction (SNCR) with ammonia or urea	Reduction of NO_X	Possible	Possible	High	Ammonia slip	Plant specific	
Selective Catalytic Reduction (SCR)	Reduction of NO_X	Possible	Possible	High	Ammonia slip	Plant specific	

Table 5.27: Techniques for the prevention and control of NO_X and N_2O emissions

5.4.8 Techniques for the prevention and control of water pollution

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Slag flushing and transport							
Closed water circuit with filtration or sedimentation units	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Regeneration of demineralisers and condensate polishers							
Inverse osmosis	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Ion-exchange	Reduced waste water discharge to about 15 to 50 % of the demineralised water	Possible	Possible	High	Sludge needs to be dewatered to be disposed of	Plant specific	
Elutriation							
Neutralisation		Only in case of alkaline operation		High		Plant specific	
Washing of boilers, air preheater and precipitator							
Neutralisation and closed loop operation, or replacement by dry cleaning methods	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Surface run-off							
Sedimentations or chemical treatment and internal re-use	Reduced waste water discharge	Possible	Possible	High		Plant specific	

Table 5.28: Techniques for the prevention and control of water pollution

5.4.9 Techniques for the handling, reduction and re-use of combustion residues

Technique	**Environmental benefit**	**Applicability**		**Operational experience**	**Cross-media effects**	**Economics**	**Remarks**
		New plants	**Retrofitable**				
Storage, transport and handling of ash							
Separate storage of bottom ash and fly ash	More flexibility to re-use different ash fractions	Possible	Possible	High	None	Not available	
Storage in closed silos	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	
Transport in big bags or silo-trucks	Reduction of fugitive dust emissions	Possible	Possible	High	None	Not available	
Utilisation of biomass ash							
Utilisation of biomass ash with low amounts of heavy metals as fertilisers	Re-use of combustion residues	Possible	Possible	High	None	Not available	It is common practise to separate the fine fraction of biomass ash which contains very high amounts of heavy metals from coarse ash. Only coarse ash can be used as fertiliser (depending on the content of nutrients and soil parameters)

Table 5.29: Techniques for handling, reduction and re-use of combustion residues

5.5 Best available techniques (BAT) for the combustion of biomass and peat

In understanding this section and its contents, the attention of the reader is drawn back to the preface of this document and in particular to the fifth section of the preface: 'How to understand and use this document'. The techniques and associated emission and/or consumption levels, or ranges of levels, presented in this section have been assessed through an iterative process involving the following steps:

- identification of the key environmental issues for the sector; which are emissions to air and water, thermal efficiency and combustion residues
- examination of the techniques most relevant to address those key issues
- identification of the best environmental performance levels, on the basis of the available data in the European Union and worldwide
- examination of the conditions under which these performance levels were achieved; such as costs, cross-media effects, main driving forces involved in the implementation of these techniques
- selection of the best available techniques (BAT) and the associated emission and/or consumption levels for this sector in a general sense all according to Article 2(11) and Annex IV of the Directive.

Expert judgement by the European IPPC Bureau and the relevant Technical Working Group (TWG) has played a key role in each of these steps and in the way in which the information is presented here.

On the basis of this assessment, techniques, and as far as possible emission and consumption levels associated with the use of BAT, are presented in this section that are considered to be appropriate to the sector as a whole and in many cases reflect current performance of some installations within the sector. Where emission or consumption levels 'associated with best available techniques' are presented, this is to be understood as meaning that these levels represent the environmental performance that could be anticipated as a result of the application, in this sector, of the techniques described, bearing in mind the balance of costs and advantages inherent within the definition of BAT. However, they are neither emission nor consumption limit values and should not be understood as such. In some cases it may be technically possible to achieve better emission or consumption levels but due to the costs involved or cross-media considerations, they are not considered to be appropriate as BAT for the sector as a whole. However, such levels may be considered to be justified in more specific cases where there are special driving forces.

The emission and consumption levels associated with the use of BAT have to be seen together with any specified reference conditions (e.g. averaging periods).

The concept of 'levels associated with BAT' described above is to be distinguished from the term 'achievable level' used elsewhere in this document. Where a level is described as 'achievable' using a particular technique or combination of techniques, this should be understood to mean that the level may be expected to be achieved over a substantial period of time in a well maintained and operated installation or process using those techniques.

Where available, data concerning costs have been given together with the description of the techniques presented in the previous chapter. These give a rough indication about the magnitude of costs involved. However, the actual cost of applying a technique will depend strongly on the specific situation regarding, for example, taxes, fees, and the technical characteristics of the installation concerned. It is not possible to evaluate such site-specific factors fully in this document. In the absence of data concerning costs, conclusions on economic viability of techniques are drawn from observations on existing installations.

It is intended that the general BAT in this section are a reference point against which to judge the current performance of an existing installation or to judge a proposal for a new installation. In this way they will assist in the determination of appropriate ‘BAT-based’ conditions for the installation or in the establishment of general binding rules under Article 9(8). It is foreseen that new installations can be designed to perform at, or even better than, the general BAT levels presented here. It is also considered that existing installations could move towards the general BAT levels or do better, subject to the technical and economic applicability of the techniques in each case.

While the BREFs do not set legally binding standards, they are meant to give information for the guidance of industry, Member States and the public on achievable emission and consumption levels when using specified techniques. The appropriate limit values for any specific case will need to be determined taking into account the objectives of the IPPC Directive and the local considerations.

To avoid duplication throughout this document, refer to BAT on Environmental Management System (EMS) in Section 3.15.1.

5.5.1 The unloading, storage and handling of biomass, peat and additives

BAT in preventing releases from the unloading, storage and handling of biomass and peat, and also for additives such as lime, limestone, ammonia, etc. are summarised in Table 5.30.

Material	Pollutants or other effects	BAT
Biomass and peat	Dust	• the use of loading and unloading equipment that minimises the height of the fuel drop to the stockpile, to reduce the generation of fugitive dust, especially when storing fine wood material and dry peat • water spray systems to reduce the formation of fugitive dust from storage areas • the moisture content of peat must be at least 40 % during transport to the plant. This eliminates fugitive dust arising from the fuel and reduces the speeding of fire, in the event of self-ignition • placing transfer conveyors in safe, open areas above ground so that damage from vehicles and other equipment can be prevented • using cleaning devices for conveyor belts to minimise the generation of fugitive dust • for dry peat and dusty biomass, enclosing conveyors with well designed, robust extraction and filtration equipment on conveyor transfer points, to prevent dust emissions • rationalising transport systems to minimise the generation and transport of dust within the site • using good design and construction practices and adequate maintenance.
	Water contamination	• having storage on sealed surfaces with drainage and drain collection, and water treatment by settling-out • collecting the surface run-off (rainwater) from biomass and peat storage areas that washes fuel particles away, and treating this collected stream (i.e. the settling-out portion) before discharge.
	Stable combustion	• carrying out quality checks of the delivered straw and subsequently storing the data on a central logistics computer • ensuring that, in the co-firing of several types of biomass, there are two or more storage systems so that the mixture of fed fuel can be controlled according to the quality of the fuels.
	Fire prevention	• surveying the biomass and peat storage areas, to detect fires, caused by self-ignition, and to identify risk points.
Lime and limestone	Dust	• having enclosed conveyors, pneumatic transfer systems and silos with well designed, robust extraction and filtration equipment on delivery and conveyor transfer points to prevent the emission of dust.
Pure liquified ammonia	Health and safety risk according to ammonia	• for handling and storage of pure liquified ammonia: pressure reservoirs for pure liquified ammonia >100 m^3 should be constructed as double wall and should be located subterraneously; reservoirs of 100 m^3 and smaller should be manufactured including annealling process • from a safety point of view, the use of an ammonia-water solution is less risky than the storage and handling of pure liquefied ammonia.

Table 5.30: BAT for the unloading, storage and handling of coal, lignite and additives

5.5.2 Fuel pretreatment

For the pretreatment of biomass, in particular for wood, classification based on the size and the contamination of the wood are considered to be BAT, in order to ensure stable combustion conditions, to reduce the amount of unburned fuel in the ash, and to thus reduce peak emissions. In case the wood used is contaminated, it is BAT to know the type of contamination of the wood and an analytical knowledge of the contaminants for each load that arrives to the power plant. To increase the thermal efficiency of peat-fired power plants, the drying system is considered to be BAT. To reduce the amount of water and to thus increase the thermal efficiency of peat-fired boilers, the drying of peat by an intermediate storage on the harvesting peat field is also considered to be part of BAT.

5.5.3 Combustion

For the combustion of biomass and peat, pulverised combustion, fluidised bed combustion, (BFBC and CFBC) as well as the spreader stoker grate-firing technique for wood and the vibrating, water-cooled grate for straw-firing are considered to be. BAT.

The use of advanced computerised control system in order to achieve a high boiler performance with increased combustion conditions that support the reduction of emissions are also considered as BAT.

With regard to grate-firing systems for biomass, spreader-stoker travelling grates are part of the BAT conclusion, because the resulting nitrogen oxide (NO_X >200 mg/Nm^3) and carbon monoxide emissions are usually low. For straw firing using the vibrating water-cooled grates, steam temperatures have to be kept below approximately 500 °C to control corrosion. Pulverised peat combustion plants have not been considered as BAT for new plants, because of their low thermal efficiency.

5.5.4 Thermal efficiency

For the reduction of greenhouse gases in particular releases of CO_2 from peat-fired combustion plants, but also for the reduction of the amount of fuel (in this sense also biomass) that is required to produce one unit of thermal energy, the best available options from today's point of view are techniques and operational measures to increase the thermal efficiency.

For peat- and biomass-fired power plants, energy efficiency has been considered as heat rate (fuel input energy/energy output at power plant border) and as power plant efficiency which is here the inverse of heat rate, i.e. percentage of produced energy/fuel input energy. The fuel energy is measured as the lower heating value.

For biomass- and peat-fired plants, co-generation of heat and power (CHP) is by far the most important technical and economical way to increase the energy (fuel) efficiency, because the electrical efficiency for a biomass- or peat-fired power plant is normally low (20 – 30 %). Co-generation in this sense is, therefore, the most important BAT measure whenever economically feasible, i.e. whenever the local heat demand is high enough to warrant the construction of the co-generation plant which is most often the case in industrial applications.

The exergetic efficiency (see also Section 2.7.5) associated with the operation of the plant under BAT conditions is considered to be 40 – 42 %. The fuel efficiency of a BAT co-generation (CHP) plant is considered to be between 75 and 90 % which corresponds to a heat rate in the range of 1.3 – 1.1. It should be borne in mind that these BAT levels are not reached under all operating conditions. The energy efficiency is as its best at the design point of the plant. The actual energy efficiencies throughout the operational period of the plants may be lower due to changes in the load during the operation, quality of the fuel, etc. The energy efficiency also depends on the cooling system of the power plant, and on the energy consumption of the flue-gas cleaning system.

For existing plants, a number of retrofit techniques can be applied to improve the thermal efficiency. Combustion efficiency, for instance, can be enhanced by the pretreatment of biofuels to reduce moisture levels. A reduction in the moisture content from 60 to 40 % could increase thermal efficiency by over 10 %. Co-combustion of biomass in coal fired power plants also results in a significantly higher electric efficiency.

In general, the following measures also need to be taken into consideration to increase the efficiency:

- combustion: minimising the heat loss due to unburned gases and elements in solid wastes and residues from combustion
- the highest possible pressure and temperature of the working medium steam
- the highest possible pressure drop in the low pressure end of the steam turbine through the lowest possible temperature of the cooling water (fresh water cooling)
- minimising the heat loss through the flue-gas (utilisation of residual heat or district heating)
- minimising the heat loss through the slag
- minimising the heat loss through conduction and radiation with isolation
- minimising the internal energy consumption by taking appropriate measures, e.g. scorification of the evaporator, greater efficiency of the feed water pump, etc.)
- preheating the boiler feed water with steam
- improved blade geometry of the turbines.

The levels of the energy (fuel) efficiency associated with the application of the BAT measures are summarised in Table 5.31.

Fuel	**Comb. Tech.**	**Unit thermal efficiency (net) (%)**	
		Electric efficiency	**Fuel efficiency (co-generation, CHP)**
Biomass	Grate-firing	Around 20	75 – 90 Depending on the specific plant application and the heat and electricity demand. Co-generation (CHP) is the most important BAT measure to achieve a high fuel efficiency and should be considered whenever the heat demand is high enough.
	Spreader-stoker	>23	
	FBC (CFBC)	>28 – 30	
Peat	FBC (BFBC and CFBC)	>28 – 30	

Table 5.31: Thermal efficiency levels associated with the application of the BAT measures

5.5.5 Dust

For dedusting off-gases from biomass- and peat-fired new and existing combustion plants, BAT is considered to be the use of bag-houses with fabric filters or an electrostatic precipitator (ESP). In this sense, it needs to be noted that when using low sulphur fuels such as biomass, the potential for reduction performance of ESPs is reduced with low flue-gas sulphur dioxide concentrations. In this context, the FF, which leads to dust emission around 5 mg/Nm^3, is the preferred technical option to reduce dust emissions.

Cyclones and mechanical collectors alone are not BAT, but they can be used as a pre-cleaning stage in the flue-gas path. The BAT conclusion for dedusting and the associated emission levels are summarised in Table 5.32. The associated dust levels take into account the need to reduce fine particulates (PM_{10} and $PM_{2.5}$) and to minimise the emission of heavy metals, since they have the tendency to accumulate preferentially on the finer dust particulates.

The BAT associated emission levels are based on a daily average, standard conditions and an O_2 level of 6 %, and represents a typical load situation. For peak load, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher, have to be regarded.

Capacity (MW_{th})	**Dust-emission level (mg/Nm^3)**		**BAT to reach these levels**	**Monitoring**	**Applicability**	**Comments**
	New plants	Existing plants				
50 – 100	5 – 20	5 – 30	FF/ESP	Continuous	New and existing plants	The reduction rate associated with the use of a fabric filter is considered to be 99.95 % or higher and is, therefore, considered as the first BAT choice for dedusting biomass- and peat-fired plants. The reduction rate associated with the use of an ESP is considered to be 99.5 % or higher.
100 – 300	5 – 20	5 – 20	FF/ESP	Continuous	New and existing plants	
>300	5 – 20	5 – 20	FF/ESP	Continuous	New and existing plants	

Notes:
ESP (Electrostatic precipitator) **FF** (Fabric filter))

Table 5.32: BAT for dedusting off-gases from biomass and peat fired combustion plants

5.5.6 Heavy metals

The mineral content of the fuel includes different substances depending on its origin. Biomass and peat have certain concentrations of trace elements, such as heavy metals. The behaviour of heavy metals in the combustion process involves complex process chemistry and physics. Basically most of the heavy metals evaporate in the combustion process and condense later in the process on the surfaces of the particulate matter (fly ash). Therefore, BAT to reduce the emissions of heavy metals from flue-gases of biomass- and peat-fired combustion plants is the use of a fabric filter (reduction rate > 99.95 %) or a high performance ESP (reduction rate > 99.5 %), where the fabric filter should be seen as the first choice in the hierarchy of BAT for dedusting.

5.5.7 SO_2 emissions

The sulphur content of peat is often low, and wood biomass contains practically no sulphur. Wood-based biomass can, therefore, be combusted in FBC without desulphurisation. The SO_2 emission level depends thus only on the sulphur content in the fuel and is typically below 50 mg/Nm^3 (O_2 = 6 %).

In the combustion of peat with a higher sulphur content or with the co-firing of biomass/peat with other fuels, e.g. coal, the reduction of SO_2, by primary and/or secondary measures (depending on the fuel mixture) are considered to be BAT.

Today, in the new smaller LCP boilers (i.e. <100 MW_{th}), fluidised bed combustion is usually applied. In these boilers, wet desulphurisation techniques are too expensive to be considered as BAT and the dry injection processes (*in situ* desulphurisation by adding limestone or dolomite to the bed) can be effective enough to reach the same emission levels. Calcium hydroxide injection in the dry form before the fabric filter or ESP can also achieve a high reduction rate. In the furnace, limestone injection together with a calcium oxide activation scrubber, is also quite effective in some cases. These measures also remove other harmful emissions, such as HCl. The HC level associated with the use of BAT is considered to be less than 25 mg/Nm^3.

The degree of desulphurisation in peat-fired FBC boilers is significantly lower than that in coal-fired FBC boilers. The degree of desulphurisation with moderate Ca/S ratios (i.e. 3 – 5) for both peat-fired CFBCs and BFBCs is around 30 – 40 %. The desulphurisation does not increase over about 45 % in BFBC boilers, even for very high Ca/S ratios. In CFBC, the highest achievable degree of desulphurisation was around 80 %, but that cannot be considered as BAT due to the very high use of limestone, which resulted in problems with the end-product and involved high costs. In CFBC with high desulphurisation (e.g. >80 %), BAT is a combination of sorbent injection into the furnace including the use of a secondary measure.

In many FBC boilers, peat and different types of wood biomass (sawdust, wood chips, bark, etc.) are co-combusted, therefore the co-combustion of peat and biomass can also be seen as one BAT option to reduce SO_2, and at the same time to also reduce CO_2 emissions from peat-fired combustion plants. It is also the case that when co-firing wood and peat, some of the sulphur in the peat reacts with the wood ash, and this acts as an additional desulphurisation agent in FBC boilers. By co-combustion of coal with biomass, the achieveble SO_2 levels depend to some extent on the sulphur content of the coal and level of co-combustion.

The BAT conclusion for desulphurisation and the associated emission levels for the combustion of peat are summarised in Table 5.33. The BAT associated emission levels are based on a daily average, standard conditions and an O_2 level of 6 %, and represents a typical load situation. For peak load, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher have to be regarded.

Capacity (MW_{th})	Combustion technique	SO_2 emission level associated with BAT (mg/Nm^3)		BAT options to reach these levels (non- exhaustive list)	Applicability	Monitoring
		New plants	Existing plants			
50 – 100	PC	200 – 300	200 – 300	Limestone injection Calcium hydroxide injection in dry form before the baghouse or ESP FGD(sds)	New and existing plants	Continuous
	FBC (BFBC and CFBC)	200 – 300	200 – 300	Co-combustion of biomass and peat, Limestone injection, Calcium hydroxide injection in dry form before the baghouse or ESP, FGD(sds)	New and existing plants	Continuous
100 – 300	PC	200 – 300	200 – 300	Limestone injection Calcium hydroxide injection in dry form before the baghouse or ESP FGD(sds)	New and existing plants	Continuous
	FBC (BFBC and CFBC)	150 – 250	150 – 300	Co-combustion of biomass and peat, Limestone injection, Calcium hydroxide injection in dry form before the baghouse or ESP, FGD(sds)	New and existing plants	Continuous
>300	PC	50 – 150	50 – 200	FGD(wet) FGD(sds) Seawater scrubbing Combined techniques for the reduction of NO_X and SO_2	New and existing plants	Continuous
	FBC (BFBC and CFBC)	50 – 200	50 – 200	Co-combustion of biomass and peat, Limestone injection, Calcium hydroxide injection in dry form before the baghouse or ESP, FGD(sds) or FGD(wet)	New and existing plants	Continuous

Notes:

PC (Pulverised combustion)
BFBC (Bubbling fluidised bed combustion)
CFBC (Circulating fluidised bed combustion)
PFBC (Pressurised fluidised bed combustion)
FGD(wet) (Wet flue-gas desulphurisation)
FGD(sds) (Flue-gas desulphurisation by using a spray dryer)

Table 5.33: BAT for the prevention and control of sulphur dioxides from peat-fired combustion plants

5.5.8 NO_X emissions

In general, for biomass- and peat-fired combustion plants, the reduction of nitrogen oxides (NO_X) using a combination of primary and/or secondary measures (e.g. SNCR and SCR) is considered to be BAT. The nitrogen compounds of interest are nitrogen oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as NO_X, and especially for FBC boilers the emission of nitrous oxide (N_2O).

For the grate-firing of biomass, in particular wood-based biomass, the spreader-stoker technique (i.e. combustion on an air-cooled travelling grate stoker) has been considered as BAT in order to reduce NO_X emissions.

For pulverised peat-fired combustion plants, the combination of different primary measures is considered to be BAT. This means, for instance, the use of advanced low NO_X burners in combination with other primary measures such as flue-gas recirculation, staged combustion (air staging), and reburning, etc.

In FBC boilers burning biomass or peat, BAT is the reduction of NO_X emissions achieved by air distribution or by flue-gas recirculation. There is a small difference in the NO_X emissions from BFBC and CFBC combustion. The lowest emission values with peat and biomass are achieved with CFBC boilers but both techniques (BFBC and CFBC) are developing towards lower emission values with no major differences currently found. The associated emission levels while using primary NO_X reduction methods in FBC for peat and biomass combustion are: for BFBC 180 – 260 mg NO_2/Nm^3 (O_2 = 6 %), and for CFBC 155 – 260 mg NO_2/Nm^3 (O_2 = 6 %). The relatively large range is mainly due to the variation in nitrogen content of the fuel (for peat between 0.7 – 2.5 %) and due to the size of the boiler. Desulphurisation by limestone injection in the boiler has been reported to increase the NO_X emission by 10 – 25 mg/Nm^3 (O_2 = 6 %).

Additionally, selective non-catalytic reduction (SNCR) by feeding ammonia or urea to the furnace is part of BAT. To avoid ammonia slip with the SNCR technique, a low layer of SCR catalyst can be installed in the economiser area of the boiler. As this catalyst reduces ammonia slip, it also reduces the corresponding amount of NO_X. In CFBC boilers, using SNCR + SCR combination, a NO_X emission of 50 mg/Nm^3 with an ammonia slip below 5 mg/Nm^3 is achievable.

Besides the use of primary measures, SCR is regarded as one possibility for the reduction of NO_X emissions and therefore as part of BAT. For straw fired plants, the application of SCR may not be possible because of rapid catalyst poisoning because of the formation of potassium compounds. SCR was introduced in the mid 90s and now there are six biomass-fired boilers operating with SCR within the energy sector. Five of these are fluidised beds (CFBC/BFBC) for co-generation and one is a small (40 MW – mixture biomass/peat) grate for co-generation. For all FBC-boilers it has been considered favourable to apply a combination of SNCR and SCR (high-dust). The grate only has a (low-dust) SCR. Typically NO_X emissions after SCR are below 30 mg/MJ (<90 mg/m^3).

The BAT conclusion for the prevention and control of NO_X emissions and the associated emission levels are summarised in Table 5.34. The BAT associated emission levels are based on a daily average, standard conditions and an O_2 level of 6 %, and represents a typical load situation. For peak load, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher, have to be regarded.

Capacity (MW_{th})	Combustion technique	NO_X emission level associated with BAT (mg/Nm^3)		BAT options to reach these levels (not exhaustive list)	Applicability	Monitoring
		New plants	Existing plants			
50 – 100	Grate-firing	170 – 250	200 – 300	Spreader-stoker		Continuous
	PC	150 – 250	150 – 300	Combination of Pm (such as air and fuel staging, low NO_X burner, etc.) SCR	New and existing plants	Continuous
	FBC(BFBC and CFBC)	150 – 250	150 – 300	Combination of Pm (such as air distribution or by flue-gas recirculation)	New and existing plants	Continuous
100 – 300	PC	150 – 200	150 – 250	Combination of Pm (such as air and fuel staging, low NO_X burner) if necessary SNCR and/or SCR	New and existing plants	Continuous
	FBC (BFBC, and CFBC)	150 – 200	150 – 250	Combination of Pm (such as air distribution or by flue-gas recirculation)	New and existing plants	Continuous
>300	PC	50 – 150	50 – 200	Combination of Pm (such as air and fuel staging, low NO_X burner), if necessary SNCR and/or SCR	New and existing plants	Continuous
	FBC (BFBC and CFBC)	50 – 150	50 – 200	Combination of Pm (such as air distribution or by flue-gas recirculation), if necessary SNCR and/or SCR	New and existing plants	Continuous

Notes:
PC (Pulverised combustion)
BFBC (Bubbling fluidised bed combustion)
CFBC (Circulating fluidised bed combustion)
PFBC (Pressurised fluidised bed combustion)
Pm (Primary measures)

Table 5.34: BAT for nitrogen oxide prevention and control in biomass- and peat-fired combustion plants

5.5.9 Carbon monoxide (CO)

BAT for the minimisation of CO emissions is complete combustion, which goes along with good furnace design, the use of high performance monitoring and process control techniques and maintenance of the combustion system. Beside the combustion conditions, a well optimised system to reduce NO_X emissions will also keep the CO levels down within the order of 50 - 250 mg/Nm^3, where emissions from FBC boilers typically are in the lower part of the interval while emission from PC and grate firing are somewhat higher.

5.5.10 Hydrogen fluoride (HF) and hydrogen chloride (HCl)

The BAT associated emission level for biomass and peat firing is <25 mg/Nm^3. For fuels not requiring sorbent injection for SO_2 reduction, and which inherent alkali content is not sufficient to meet the BAT level, additional alkali injection is a part of BAT.

In combustion plants using straw as a fuel, the variation in the HCl emissions is from 50 to 300 mg/Nm^3 (daily mean value) with a typical yearly mean value of 100 mg/Nm^3. For larger straw-fired plants, the application of a wet scrubber or a spray dry scrubber system is considered as part of BAT if higher amounts of HCl have been measured. Both wet scrubber or spray dry scrubber systems reduce HCl (with a reduction rate of about 98 %). SO_2 emissions, which can be up to 300 mg/Nm^3 in the raw gas of a straw fired plant, can also be reduced (with a reduction rate 80 – 95 %). In this case, the associated HCl emission level is between 5 and 25 mg/Nm^3.

Because of the generation of HCl, straw firing leads to a high risk of high temperature corrosion particularly in the superheater section of the boiler.

5.5.11 Ammonia (NH_3)

One disadvantage of SNCR and SCR systems is the emission of unreacted ammonia into the air (ammonia slip). The ammonia emission concentration associated with the use of BAT is considered to be below 5 mg/Nm^3.

5.5.12 Dioxins and furans

In some biomass fired plants, especially wood-fired combustion plants, the emissions of dioxins and furans have been measured and an emission level of below 0.1 ng/Nm^3 is generally regarded as achievable.

5.5.13 Noise

Special care has to be taken when cutting straw needed for co-firing with coal in pulverised fuel boilers. BAT for cutting straw is to use hammer-mills (which have a high noise level). Special attention has also to be paid to subsequent pneumatic transport to the burner.

5.5.14 Water pollution

Different waste water streams (see Chapter 1) are generated by operating biomass- and peat-fired combustion plants. To reduce emissions to water and to avoid water contamination, all measures that have been presented in Section 5.4.8 are considered to be BAT and summarised in the Table 5.35.

Technique	Main environmental benefit	Applicability	
		New plants	Retrofitted plants
Wet FGD (only applied if necessary under the conditions of Section 5.4.8)			
Water treatment by flocculation, sedimentation, filtration, ion-exchange and neutralisation	Removal of fluoride, heavy metal, COD and particulates	BAT	BAT
Closed loop operation	Reduced waste water discharge	BAT	BAT
Mixing of waste water with ash	Avoided waste water discharge	BAT	BAT
Slag flushing and transport			
Closed water circuit by filtration or sedimentation	Reduced waste water discharge	BAT	BAT
Regeneration of demineralisers and condensate polishers			
Neutralisation and sedimentation	Reduced waste water discharge	BAT	BAT
Washing of boilers, air preheaters and precipitators			
Neutralisation and closed loop operation, or replacement by dry cleaning methods	Reduced waste water discharge	BAT	BAT
Surface run-off			
Sedimentations or chemical treatment and internal re-use	Reduced waste water discharge	BAT	BAT

Table 5.35: BAT for the reduction of waste water contamination

As previously mentioned in Section 5.4.1, as BAT it has been considered that biomass and peat should be stored on sealed surfaces with drainage and drain collection, or in silos, or enclosed storage areas. The surface run-off (rainwater) of the storage areas that washes fuel particles away should be collected and treated (settling-out) before discharge. The associated BAT emission level in the discharged water is considered to be less than 30 mg/l.

Small amounts of oil contaminated (washing) water cannot be prevented from occurring occasionally at a power plant. Oil separation wells are, in general, sufficient to avoid any environmental damage.

In general, the other techniques described for waste water treatment in Chapter 3 can also be considered as BAT for this sector.

5.5.15 Combustion residues

Attention has been paid by industry to the utilisation of combustion residues and by-products, instead of depositing them in landfills. Utilisation and re-use is, therefore, the best available option.

There are a vast number of different possibilities for the re-use of different by-products. Each different utilisation sets specific criteria for the quality of ash. It is impossible to cover all of these criteria in this BAT reference document. As a minimum it will suffice to say that the quality criteria are usually connected to the structural properties of the ash and the content of any harmful substances such as the amount of unburned fuel in the ash, the solubility of heavy metals, etc.

5.6 Emerging techniques for the combustion of biomass and peat

Gasification of peat and biomass

Pressurised gasification in an integrated gasification combined cycle (IGCC) is one of the high efficiency technologies which could reduce emissions, including greenhouse gas CO_2, from large scale power production based on solid fuels. Peat is an ideal fuel for gasification because of its high volatile content. The present status in developing biomass-fired IGCC technology in the Nordic countries is such that a demonstration unit is currently under construction in Sweden.

The gasification of straw has only been tested successfully when done together with coal, so the gasification of straw alone needs further development before it could be commercially available.

6 COMBUSTION TECHNIQUES FOR LIQUID FUELS

6.1 Applied processes and techniques

6.1.1 Unloading, storage and handling of liquid fuels

Liquid fuels are supplied by pipeline, ship, train and lorry, depending on the availability of transport systems at the oil-well, refinery and LCP site. Liquid fuels are processed in refineries for direct use in engines, domestic combustion systems and LCPs. Unloading is normally carried out with pipelines.

Fuel oil is stored in vertical steel cylindrical (vented or floating roof) storage tanks. The tank capacity varies from 1000 m^3 to 100000 m^3, depending on the number of tanks and the size of the station. The tanks are generally grouped inside a bund (retention basin), which can hold all or a part of the volume (e.g. 50 – 75 % of the overall maximum capacity of all the tanks but at least equal to the maximum volume of the largest one) of stored fuel oil in the event of a leak or other damage to the tanks (e.g. fire, explosion, pipe breakage, etc.). The bund must be perfectly sealed and should incorporate oil interceptors to prevent the discharge of oil into site run-off water.

Depending on climatic conditions at the site and the type of fuel oil stored, storage tanks may need to be equipped with heating systems to bring the fuel oil (in particular heavy fuel oil (HFO)) up to the appropriate temperature for its transfer and in order to ensure correct atomisation in the burner,.which is an important pollution control technique. In such cases, the tanks have to be properly insulated. There are two types of heating systems which can be generally used to warm up the fuel oil: ‘bottom’ heaters, which warm up the entire volume of fuel oil; or ‘recovery’ heaters, which are located just before the suction piping and heat up the fuel oil only as it is leaving the storage tank. Note, light distillate oil does not need to be heated for pumping or for atomisation.

The venting of gases from the storage tank back into the delivery tank is frequently practised unless floating roof storage tanks are used. The automatic resealing of connecting hoses is used when liquids are delivered. Delivery connections are sited inside the bund.

Regular checks of the tank contents to identify leaks and to check the fill level are common practice. Automatic systems, incorporating alarms, are used to check the fill level. Inertised atmospheres are occasionally used. Regular checks of the storage facilities and piping are common practice and part of good plant management.

Pipelines used for liquid fuel delivery incorporate intermediate tank storage. Fuel distribution from the site storage tanks to the burners is usually by overhead pipelines or by service trenches, or less commonly by buried pipeline. Barriers are used to protect overhead pipelines against damage. When using underground pipes, ‘state-of-the-art’ is to use double walled pipes with automatic control of the spacing and special constructions (e.g. steel pipes, welded connections with no valves in the underground section, etc.).

If there is a risk of groundwater contamination, the storage area should be impermeable and resistant to the fuel stored. Depending on the flashpoint of the liquid fuel, there may be a danger of explosion.

6.1.2 Pretreatment of liquid fuels

6.1.2.1 Pretreatment of oil used in conventional boilers

Petroleum products, such as heavy and light fuel oils, used as fuel for large combustion plants are processed in a refinery, in order to comply with national and international fuel specifications. The different oil qualities used for different types of LCPs are described in Table 6.13. An important impurity in the combustion of liquid fuels is the amount of sulphur present in the fuel. Although fuel oil can be processed in the refinery to reduce the sulphur content, techniques to reduce the sulphur content of oil are not part of the scope of this document and are, therefore,described the BREF for Mineral Oil and Gas Refineries.

6.1.2.2 Pretreatment of liquid fuels used in gas turbines

Only refined liquid fuels can be used directly in oil-fired gas turbines. The oil has to be raised to the necessary input pressure before combustion in the gas turbine.

Diesel oil, when used as a fuel in modern gas turbines, needs to be treated in order to reduce its sodium, potassium and calcium concentrations and to remove solid impurities, which are otherwise detrimental to the turbine blades. Diesel oil is treated at the ‘fuel treatment plant’, which comprises diesel oil cleaning units, either a self-cleaning centrifuge unit or an electrostatic type unit, and all the necessary pumps and piping equipment. All the waste from the plant is collected and discharged to the waste water treatment plant.

If heavy fuel oil (HFO) is to be used as the fuel in modern gas turbines, a special treatment procedure is required. In this case, the fuel treatment plant comprises heaters, for heating the untreated HFO (electrical or steam coil type); de-emulsifier dosing systems, for breaking up the oil emulsion; separators (centrifugal or electrostatic type), for removing the solid impurities in the HFO, particularly for fuels with a high ash content; additive dosing systems, for raising the melting point of the vanadium oxidation products; and all the necessary pumps and piping equipment. All the waste from the plant is collected and discharged to the waste water treatment plant.

The main requirements of any fuel for use in gas turbines are:

- high calorific value
- high consistency of heat input to the turbine
- high cleanliness
- low corrosiveness, either to accessories or to hot turbine blades
- low deposition and fouling tendencies, especially on hot turbine blades.

6.1.2.3 Pretreatment of liquid fuels for diesel engines

In order to ensure correct pumping and operating conditions, diesel engines need a continuous supply of cleaned and filtered fuel oil at the correct flow and viscosity (for HFO typically below: 730 cSt at 50 °C). For heavy fuel oil, HFO treatment plants similar to those for gas turbines are applied, but with the following differences: only centrifugal separators are used and electrical or steam coil type heaters for heating up the HFO to the appropriate temperature (in order to achieve the required injection viscosity typically 12 – 20 cSt for a good atomisation at the nozzle); and in normal cases, de-emulsifier dosing systems (for breaking up the oil emulsion) are not used, and neither are dosing systems, for raising the melting point of vanadium products.

6.1.3 Oil-fired boilers

Boilers designed for burning liquid fuels such as heavy fuel oil are very similar to boilers that are used for the combustion of coal. A typical heavy fuel oil boiler is shown in Figure 6.1.

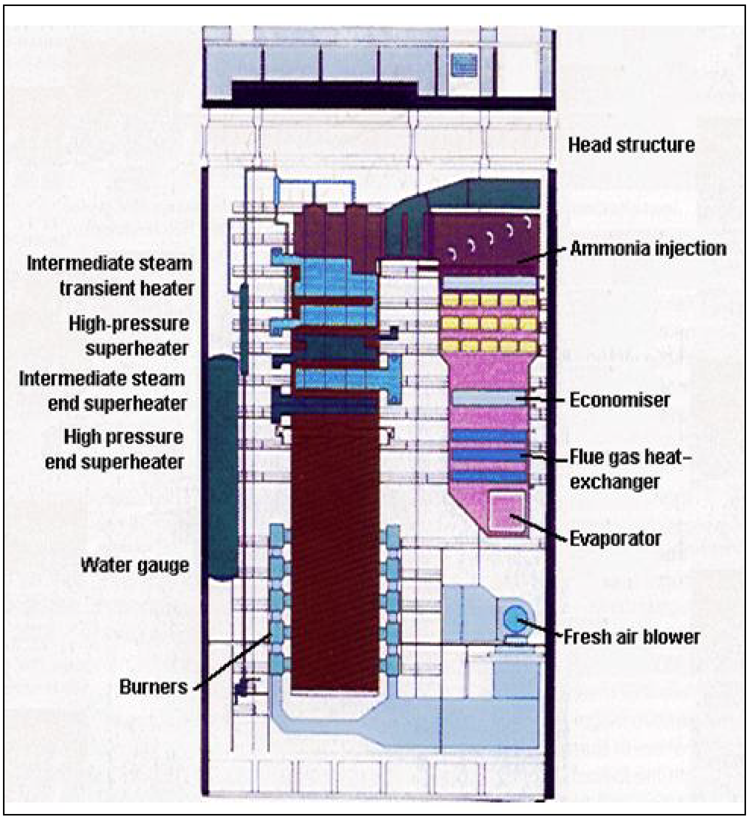


Figure 6.1: Heavy fuel oil boiler
[43, Wienstrom, 2001]

The firing systems used in liquid fuel combustion boilers are similar those used in combustion plants where coal is used as a fuel. To achieve a homogeneous combustion, fine aerosol droplets measuring from 30 to 150 µm are sprayed into the boiler by a mechanical process, or through the action of an auxiliary fluid (air or steam) under pressure, or even through a combination of both.

All burner designs are supplied directly with air. When heavy fuel oil is used, low viscosity is needed at the burner, in order to ensure correct atomisation of the fuel. To obtain this viscosity, the heavy fuel oil must be heated to around 120 – 140 ºC. Additives are used to improve the combustion of heavy fuel oil.

Wall- or front-firing systems: In horizontally wall-fired systems, the fuel is mixed with combustion air. The burners are located in rows, either on the front wall only or on both the front and rear walls. The latter arrangement is called ‘opposed firing’.

Tangential- or corner-firing systems: The tangentially-fired system is based on the concept of a single flame envelope. Both fuel and combustion air are projected from the vertical furnace corner windboxes along a line tangent to a small circle.

There are three major technical issues that need to be taken into consideration when firing heavy fuels:

- the need for heated storage, transportation and additional heating before atomisation, due to the high viscosity of the HFO
- its tendency to form coke particles
- the formation of corrosive deposits.

The first two points are caused by the high molecular weight and the asphaltene nature of some of the constituents. The second and the third points stem from the presence of sulphur, nitrogen, vanadium and other metals in the fuel.

With emulsions, the physical effects of a water addition lead to better combustion properties by improving the atomisation. Micro-explosions are produced as a result of the formation, growth and bursting of vapour bubbles within the superheated droplet. Since the oil can sustain very high temperatures during combustion, the water droplets can be superheated. The emulsion droplet is eventually shattered by the internal formation of water bubbles and their rapid vaporisation. This process is called secondary atomisation, and increases the evaporation surface area and the mixing of the burning species in air. The amounts of particulates and smoke formed are minimised [87, Molero de Blas, 1995].

6.1.4 Oil fired combustion installations for industrial applications (process heater)

Process heaters are sometimes referred to as process furnaces or direct fired heaters. They are heat transfer units designed to heat petroleum products, chemicals, and other liquids and gases flowing through tubes. The liquids or gases flow through an array of tubes located inside a furnace or heater. The tubes are heated by direct fired burners that use standard specified fuels such as HFO, LFO, and natural gas, or the by-products from processes in the plant, although these may vary widely in composition. Vertical furnaces could be oil-fired with a reduced number of air forced burners. This combustion system allows good air control, reduces excess air, improves the energy efficiency and lowers pollutant emissions. Air combustion could be preheated in a way which decreases energy consumption.

Using tubes to contain the load is somewhat unique compared to other types of industrial combustion applications. It was found that heating the fluids in tubes has many advantages over heating them in the shell of a furnace. The advantages include: a better suitability for continuous operation, better controllability, higher heating rates, more flexibility, reduced risk of fire, and the use of more compact equipment.

Heating is carried out to raise the temperature of the fluid for further processing downstream or to promote chemical reactions in the tubes. The primary modes of heat transfer in process heaters are radiation and convection from the energy generated by burning the fuel in the burners. There may be anywhere from 1 to over 100 burners in a typical process heater, depending on the design and process requirements. Burners can be located in the floor; or on the wall on multi-levels, firing vertically upward; or on the wall, firing radially to the centre of the heater [180, Baukal and Schwarz, 2001].

6.1.5 Fluidised bed firing

In fluidised bed boilers (FCBs), liquid fuels (e.g. high sulphur HFO or residues) are sometimes burned supplementary to other fossil fuels such as coal.. Desulphuration occured into the fluidized bed who has to be fed with limestone, Due to the very small amount af ashes produced by oil combustion, limestone consumption could be important. An other effect is the lower NO_X emissions connected with the low combustion temperature into the fluidised bed.

6.1.6 Compression ignition (diesel) engines

In the 1960s and 1970s, engine driven power plants were mostly used for running short-time applications such as emergency and peaking production and small scale power production, but today reciprocating engines are widely used, especially for continuously running power generation applications. Both larger base load engine driven power plants with an output of up to 200 MW_e and decentralised smaller simultaneous heat and power (CHP) production plants are common today worldwide. One reason for this trend is the development in recent decades of high efficiency medium and low speed engines suitable for base load operation. Medium speed diesel engine units with a fuel input of up to 50 MW_{th} or more, gas diesel engines (‘high pressure’ and ‘low pressure (dual fuel)’ types) with a fuel input of up to 40 MW_{th} are available on the market. Low speed diesel engine units have a fuel input of 130 MW_{th} or more, and gas diesel engine units have a fuel input of up to 85 MW_{th}.

Nevertheless, in Europe, few such plants exist in interconnected systems for power generation with liquid fuels. The applications are limited to more isolated systems (e.g. operated on islands) where no other fuel supply possibility exists.

The advantages of the reciprocating engine for this kind of application are many, e.g. high thermal efficiency (low fuel consumption), optimum set-up for matching different load demands, short construction time, easy maintenance and robust design.

Other attractive advantages of the engine driven power plant, especially from an environmental point of view, are that these power plants can be located in urban areas or in industrial areas close to the consumers of the heat and electricity. Less transmission lines are then needed and the associated energy losses and land demand can be minimised. Engine driven CHP plants are well suited for, e.g. industry applications, local utility companies, residential and commercial buildings. Heat can be recovered as steam, hot water, hot air, etc. Possible utilisation options for the recovered heat are in district heating/cooling, desalination processes, and to preheat the air for some processes, etc. The optimum heat/power ratio for a reciprocating engine plant is typically about one (in a high grade heat plant) compared to a low grade heat system with typically a heat/power ratio of 3/2 or higher. In many places, the amount of heat utilisation acts as the bottleneck (i.e. the electricity demand is growing, but the heat demand is static), so by using a high grade heat plant, the CHP operation can be implemented more easily.

Diesel engines are fuel flexible and can use fuels such as diesel oil, heavy fuel oil, gas, crude oil, biofuels and even, in a few cases, orimulsion. In a diesel engine, air is forced into the cylinder and is compressed by the piston. Fuel is injected into the cylinder and is ignited by the heat of the air compression. The burning mixture of fuel and air expands, pushing the piston. Finally the products of combustion are removed from the cylinder, completing the cycle. The energy released from the combustion of fuel is transferred to the engine flywheel via the moving piston. An alternator is connected to the rotating engine flywheel and produces electricity.

In heavy fuel oil operation, the fuel is first pre-cleaned and heated in the fuel treatment system before injection into the engine. The filters and separators in the fuel treatment system remove impurities and water in the fuel. The heavy fuel oil is preheated to the required viscosity, for good fuel atomisation at the nozzle. The liquid fuel pressure is boosted to about 1100 – 1800 bar (dependent on engine type) to achieve a droplet distribution small enough for fast and complete combustion. When operating with light fuel oil no preheating or separation of the fuel is usually needed. The nozzle design for the fuel inlet is one of the key factors for the combustion process.

Combustion is realised partially at constant volume with an increase in the pressure, with the main combustion process occurring at constant pressure. Combustion is not continuous but occurs only during one part of the cycle. End-of-compression pressure and temperature are important parameters to ensure good combustion. Maximum pressure must be limited to prevent damage. The engine materials can bear temperatures of about 1200 °C, which allows a maximum cycle temperature of 2500 °C. Thus the efficiency of this kind of engine is around 40 - 50 %.

The dual fuel engine

The dual fuel engine is a new engine type on the market developed for countries where natural gas is available. The engine type is fuel versatile, it can be run on low pressure natural gas or liquid fuels such as diesel oil (back-up fuel, etc.), heavy oils, etc. and it can operate at full load in both fuel modes. In the gas mode, the engine is operated according to the lean-burn principle, i.e. there is about twice as much air in the cylinder compared to the minimum needed for complete combustion of the gas. This allows a controlled combustion and a high specific cylinder output without immediate risk of knocking or self-ignition. In gas engines, the compression of the air/gas mixture with the piston does not heat the gas enough to start the combustion process, therefore some additional energy needs to be added and this is carried out by injecting a small pilot fuel stream (for instance diesel oil). As a liquid fuel such as diesel oil has a lower self-ignition temperature than gas, the heat in the cylinder close to the top position is enough to ignite the liquid fuel which, in turn creates enough heat to cause the air/gas mixture to burn. The amount of pilot fuel is typically below one to two per cent of the total fuel consumption at full load. This engine works according to the diesel process when liquid fuel is used and according to the Otto-cycle when gas fuel is used. The burning mixture of fuel and air expands, pushing the piston. Finally the products of combustion are removed from the cylinder, completing the cycle. The energy released from the combustion of the fuel is transferred to the engine flywheel via the moving piston. An alternator is connected to the rotating engine flywheel and produces electricity [88, Euromot, 2001].

6.1.7 Liquid fuel-fired gas turbines

Gas turbines powered with liquid fuels (not as the back-up fuel) are very rarely applied in Europe. This is due to the high costs of such fuels, mainly light distillate oil; and the stress imposed by liquid fuels on gas turbine blades and rest systems compared to natural gas. Therefore, applications are very rare and only in those cases where a natural gas supply does not exist. Two types of liquid fuel-fired gas turbines are currently applied: heavy duty gas turbines and gas turbines derived from aeroplane engines, so-called aeroderivatives.

By means of an axial compressor, pressurised air is driven, into the combustion chambers, where the fuel injectors are connected. During the combustion reaction, the gas temperature rises, and at between 1000 and 1350 °C it is introduced into the turbine. These hot gases are depressurised in the turbine, which simultaneously drives both the air compressor and the alternator, which in turn generates electricity. In the ‘open cycle’ configuration, the combustion gases are released directly into the atmosphere at a temperature of >450 °C. The thermal efficiency is then between 30 and 40 %.

Gas turbines (GT) can operate with a wide range of liquid fuels, such as residual fuel naphtha. Gas turbines in general and aeroderivatives in particular run on light distillate fuel oil or on kerosene. For recent designs of turbines, which have high turbine inlet temperatures, the manufacturers’ specifications for fuel supplies are very stringent. They stipulate the physical and chemical properties needed in order to meet both the equipment demands and the environmental standards, particularly with regard to metal contaminants (sodium, potassium, lead, vanadium, calcium), sulphur and ashes.

6.1.8 Co-generation (CHP)

Co-generation uses a single process to generate both electricity and usable heat. Co-generation, i.e. the ‘combined generation of heat and power’ (CHP), is a proven technology and is mainly applied to industrial plants where both electricity and heat (hot water or steam) are needed. In addition to cost savings, co-generation also yields environmental benefits through using fossil fuels more efficiently. This leads to fewer emissions than the separate generation of electricity and heat and in an optimised fuel and exergetic efficiency.

Steam turbines driven by any fossil fuel-fired boilers have been used for industrial co-generation systems for many years. High pressure steam raised in a conventional boiler is expended within a turbine to generate mechanical energy, which can then be used to drive an electric generator. The power generated depends on how far the steam pressure can be reduced though the turbine whilst still meeting the site heat energy needs.

Stationary engines are also well suited and popular for co-generation (CHP) i.e. for hot water production, steam generation (sometimes with an additional steam turbine for enhanced electrical efficiency), desalination of seawater, district cooling systems and for heating air. The total fuel efficiency of this kind of installation is very high, up to 90 % in some applications. The heat-to-power ratios for engine CHP applications are typically from 0.5 to 1.3. As an example, the specific CO_2 emission for co-generation (CHP) plants is 370 g/kWh (produced electricity + recoverable heat) when operating on HFO (heavy fuel oil) at a total plant efficiency of about 80 % [88, Euromot, 2001].

Gas turbines could be used in specialised co-generation (CHP) plants, as above. Industrial complexes can produce electricity on-site when large heat-to-power ratios exist, i.e. ranging from 1.5 to 3.

6.1.9 Combined cycle combustion

The idea of combined cycles has grown out of the need to improve the simple Joule-cycle efficiency by utilising the waste heat in the turbine exhaust gas. This is a natural solution because the gas turbine is a relatively high temperature machine and the steam turbine a relatively low temperature machine.

Combined cycle combustion systems can be used for liquid fuels in the same way in which they are used for other fuels. Heavy or light fuel oil is sometimes used for additional firing in heat recovery boilers or as a supplementary fuel in natural gas-fired plants, where it can also be used as back-up fuel.

6.1.10 Control of emissions to air

When using heavy fuel oil (HFO), emissions of NO_X and SO_X which lead to air pollution, arise from the sulphur and, to a certain extent, from the nitrogen contained in the fuel. Particulates originate mainly from the ash content and marginally from heavier fractions of the fuel [146, UFIP, 2001]. The presence of particulates can also lead to economic costs to the operators, from losses due to unburned fuel and from deposits in combustion facilities, if the equipment is not well maintained.

6.1.10.1 Control of emissions to air from liquid fuel-fired boilers

6.1.10.1.1 Abatement of particulate emissions

Particulate emissions from the combustion of heavy oils may contain two major fractions [87, Molero de Blas, 1995]:

1. Material arising from the organic content of the fuel and its failure to complete the burnout process:

- unburned hydrocarbons (smoke)
- particulates formed via gas phase combustion or pyrolysis (soot)
- cenospheres produced from cracked fuel or carbon along with ash (coke).

2. Ash from the inorganic content of the fuel:

Smoke may arise from unburned fractions of hydrocarbon fuel exhausted in the form of a fine spray. Such hydrocarbon fractions are the remainders of reactions frozen by thermal quenching. Emissions of unburned hydrocarbons are highest at high equivalence ratios (fuel rich conditions). Their main environmental effect is their reactions in the atmosphere with NO_X and sunlight to form photochemical smog.

Soot is formed in gas-phase reactions of vaporised organic matter in a complex process involving fuel pyrolysis, polymerisation reactions, nucleation, particle growth and burn-out. Fuel droplets burning in envelope flames are subjected to very high temperatures, leading to fuel evaporation and thermal cracking of the large molecular structures, thus resulting in species of higher C/H ratio than the fuel source. Soot is most likely to be formed in fuel rich conditions, and is normally fully burned as it mixes with air at a very high temperature in highly oxidising zones, e.g. as secondary air is injected into the combustion chamber of a gas turbine.

Coke particulates are formed in liquid-phase processes, and contain all the non-soot carbon and also part of the ash material. Such particles are nearly spherical, hollow and porous, and they range in size from 1 to 100 µm.

Ash fouling and corrosion are major problems when burning heavy oils. Vanadium and sodium are the most harmful elements, forming vanadium pentoxide (V_2O_5) and sodium sulphate (Na_2SO_4) respectively. Ash deposits jeopardise heat transfer to metallic surfaces and cause corrosion of the combustion hardware, thus decreasing the equipment lifetime. Values given in the literature [87, Molero de Blas, 1995] show that a mere 0.32 cm thick deposit can cause a 10 % decrease in turbine power.

Solid particulates cause corrosion, erosion and abrasion, all of which reduce the lifetime of the hardware. Carbon particulates may also increase the radiative power of the flame, causing damage to the combustion chamber materials. In addition, there is an economic loss from losing unburned material to the air, which therefore means a decrease in fuel efficiency [87, Molero de Blas, 1995].

Because of the effects mentioned above optimum combustion conditions are important for the minimisation of particle and ash production. Viscous fuel must be preheated before atomising. Additives combine with fuel constituents and combustion products to form solid, innocuous products that pass harmlessly through the combustion equipment and may be used to support the optimum combustion conditions. Additives could largely reduce the amount of unburned carbon to a value as low as 5 % in weight in the collected ashes. Regarding the content of unburned carbon in ash, the target is to achieve the best burnout possible in order to achieve an optimum efficiency or fuel utilisation. However, according to technical and fuel characteristics, a higher content of unburned carbon in ash may happen in HFO firing. Ashes with high content carbon are black while those with low carbon content are yellow or grey.

In older oil-fired boilers, burners with mechanical atomisation were installed. The improved design of burners with steam atomisation gives a more efficient combustion of HFO, and results in lower particulate emissions. PM emission concentrations in the raw gas (before dedusting) of lower than 100 mg/Nm^3 may be achieved, though this depends greatly on the ash content of the HFO.

Particulate emissions are normally reduced by ESPs. Particles are generally collected in an ESP in a dry form, which can then be landfilled in controlled landfills. Ash resulting from fuel oil combustion could have a large amount of carbon content and, in this case, it can be incinerated. However, under good combustion conditions of liquid fuel, low carbon content ash (lower than 20 %) is obtained and it should be landfilled in controlled landfills. Fly ash from oil firing installations is regarded as hazardous waste.

In the older oil-fired boilers, burners with mechanical atomisation were installed. Improved design of burners with steam atomisation have shown more efficient combustion behaviour of HFO, resulting in lower particulate emissions. PM emission concentrations of lower than 100 mg/Nm^3 in untreated raw gas may be achieved, though depending greatly on the ash content of the HFO. The amount of PM can then further be reduced by applying secondary dedusting devices such as ESP.

6.1.10.1.2 Abatement of SO_2 emissions

Sulphur is usually found in hydrocarbon fuels, normally up to a maximum of 3 % by weight, and mostly in organic form, although it also exists as inorganic compounds. Heavy fuel oils usually contain higher amounts of S than other petroleum products, as it tends to concentrate in the residue along with asphaltenes during the refining processes.

At the high temperatures and oxygen concentrations typical of combustion, sulphur combines with carbon, hydrogen and oxygen to form SO_2, SO_3, SO, CS, CH, COS, H_2S, S and S_2. Under such circumstances, almost all of the sulphur is in the '+4' oxidation state, hence SO_2 is the predominant sulphur compound formed in combustion. Even with a 20 % air deficiency, 90 % of the sulphur is in the form of SO_2 and as little as 0.1 % is as SO_3; with SO accounting for the remainder of the sulphur.

At a lower oxygen concentration (40 % deficiency), H_2S, S_2 and HS are also present in significant proportions, while SO_3 is negligible. During combustion, these species are in super-equilibrium concentrations. As the gases cool, their rates of consumption decrease and equilibrium may be 'frozen' before the products reach room temperature [87, Molero de Blas, 1995].

In oxygen rich and in stoichiometric flames which are very close to normal operations in boilers, SO_2 and a very little amount of SO_3 are present. SO_3 has to be as low as possible to minimise H_2SO_4 formation. Sulphuric acid is responsible for corrosion in the coldest sections of the boiler.

Switching to low-sulphur oil might be a technique which can make a significant contribution to SO_2 emissions reduction. A decrease of 0.5 % in the oil sulphur content leads to a decrease in the emission value by about 800 mg/Nm^3 at 3% of oxygen in the waste gas.

Co-combustion, i.e. simultaneously burning of liquid and gaseous or liquid fuel and biomass might also be a technique which could make signifiant contributions to SO_2 emission reduction with an important effect on the local air pollution. Co-combustion could take place in the same burner or in different burners located in the same combustion chamber.

To reduce SO_2 emissions from liquid fuel-fired boilers, especially those burning HFO, some plants apply wet scrubbers. Figure 6.2 shows a wet scrubber applied to an Austrian HFO fired boiler. Wet scrubbing with gypsum as the end-product is the best performing process for desulphuration. Nevertheless, due to economic and operational constraints, it might not be applicable to small and medium sized boilers. For that size boilers, waste gas desulphuration could be carried out with lime or limestone dry processes, lime semi-dry processes, activited carbon processes, or soda and sodium carbonate processes.

Dry desulphuration could be improved by managing an 'open pass' on the inside of the boiler that increases the contact time at a constant of temperature between sorbant and waste gases. The choice between the above processes depends on the required yield of desulphuration and of local considerations, i.e. mainly utilisation or landfilling of desulphuration by-products and residues.

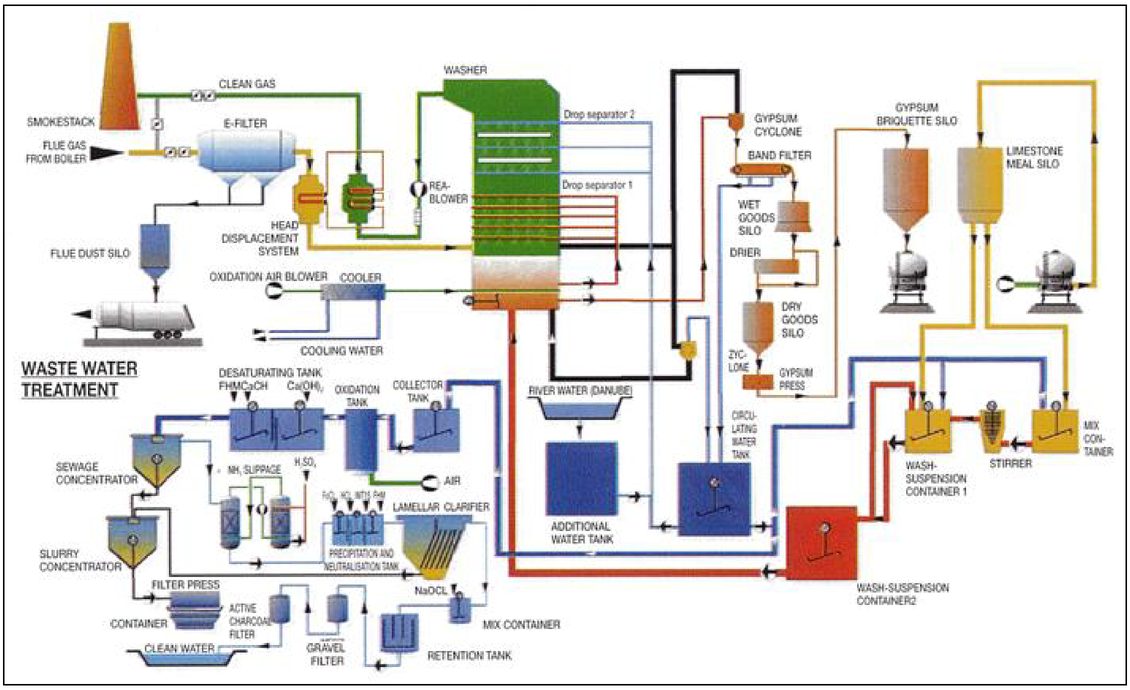


Figure 6.2: Wet FGD process applied to a HFO fired boiler
[43, Wienstrom, 2001]

6.1.10.1.3 Abatement of NO_X emissions

With conventional fuels, the NO_X formation rate very much depends on the gas temperature and the amount of nitrogen in the fuel. Both characterise the most important routes for the formation of NO_X. Thermal NO_X can be controlled through a reduction of the flame peak temperature (e.g. limited combustion chamber load). The NO_X concentration in the exhaust of an oil-fired boiler indicates that the NO_X concentration decreases with excess air. The boiler size also plays an important role in the concentration of NO_X in the flue-gases. Factors such as the method of firing have little influence.

For oil-fired boilers, the usual excess air is in the range of 2 – 4 % O_2 (in flue-gas). A low excess air combustion will be characterised by 1 – 2 % O_2. This technique is rarely used alone, but is very often used in combination with '**low NO_X burners**' or '**overfire air**'.

Flue-gas recirculation is more often used in oil- or gas-fired boilers than in coal-fired ones. This technique is often used in combination with low NO_X burners and/or OFA, together achieving a 60 – 75 % reduction from the original NO_X emission baseline level.

Amongst all the **air-staging** techniques, the most commonly used in oil-fired boilers are 'burners out of service' (BOOS) and 'Overfire Air' (OFA). With modern OFA designs (optimised nozzle design, separated and swirled air flux), the NO_x reduction can be as high as 60 % in tangential firing units.

Flue-gas recirculation type burners are used in oil-fired boilers, matched with the various types of **low NO_X burners** [146, UFIP, 2001] and achieves a corresponding NO_X emission reduction of 20 %. The key point in designing an efficient oil LNB is to ensure a good oil atomisation coupled with the burner aerodynamics, so as not to increase the carbon-in-ash level while decreasing NO_X. Modern LNB designs with a proper oil atomisation system can reach a 50 % NO_X reduction. For oil-fired plants in general, the NO_X emission reduction limits with low NO_X burners are 370 - 400 mg/Nm^3 (at 3 % O_2).

In oil-fired boilers, **reburning** [146, UFIP, 2001] can be implemented with gas or oil as the reburning fuel. Gas is more commonly used than oil. Reburning is interesting for new power plants but is less adapted to existing units. Many existing oil-fired boilers have been equipped with gas/oil reburning during recent years (e.g. Italy has units from 35 to 660 MW_e). It is important to note that these units have all been equipped with at least OFA and flue-gas recirculation at the same time, and some of them with low NO_X burners. The share of the reburning fuel is 10 to 20 % of the total thermal input. The corresponding NO_X reduction is 50 - 80 % from the original NO_X baseline level for oil reburning and 65 – 80 % for gas reburning.

Secondary measures such as SNCR and SCR systems have been applied to a number of oil-fired combustion plants. In Europe, SCR systems are applied, in particular, in Austria, Germany, Italy and the Netherlands, whereas outside Europe they are mostly applied in Japan. The SCR technology has proven to be successful for liquid fuel-fired power plants.

SNCR processes can be applied to any size oil fired boilers. SNCR processes include liquid NH_3, gaseous NH_3, and liquid urea and solid urea as reduction agents. One of these reduction agents is injected into the boiler chamber in areas where the temperature is around 900 °C. SNCR need a good knowledge of temperature distribution in the combustion chamber at all rates, and a good control of the amount of injected products. Control can be achieved by NH_3 or NO_X monitoring, NO_X reduction could reach 60 % with a NH_3 slip lower than 10 ppm.

6.1.10.2 Control of emissions to air from liquid-fuel-fired process heaters

Due to the wide range of fuels that can be used to operate process heaters, emissions, which are mainly NO_X, SO_2 and dust are vented to the air. To reduce emissions from process heaters, the following abatement strategies are used [180, Baukal and Schwarz, 2001]:

- **combustion modification (primary measures):** There are numerous methods that have been used to modify the combustion process. A popular method is a **low-NO_X burner** design. As in other combustion plants, low NO_X burners such as premixed burners, staged air and staged fuel burners are used to reduce the generation of NO_X emissions. Other ways include low excess air, staging and fuel gas recirculation, water or steam injection, and reburning (e.g. methane reburn). Emissions of NO_X for instance can also be reduced by minimising air infiltration into the heater. Air infiltration, sometimes referred to as 'tramp air' into a heater affects the excess air and can affect the NO_X emissions. The additional benefit from reducing the excess air is the increase in thermal efficiency, this results as any unnecessary air absorbs heat that is then carried out of the stack rather than being used for design purposes

- **co-combustion of oil and gas:** Co-combustion of oil and gas is used in process heaters for several reasons:

  - decreasing SO_2 emissions
  - modification of flame pattern in aim to optimise heat transfer to the tubes
  - utilisation of fuel gas that could not be exported outside of chemical plants or refineries.

- **post-treatment (secondary measures):** The most common secondary measures are selective catalytic reduction (**SCR**) and selective non catalytic reduction (**SNCR**), and dedusting devices, such as ESPs when firing HFO. When using HFO, wet and dry FDG can be applied as well in order to reduce emissions of SO_2. One of the advantages of secondary measures is that multiple exhaust streams can be treated simultaneously, thus achieving economics of scale.

6.1.10.3 Control of emissions to air from liquid fuel-fired (diesel) engines

The main pollutants emitted in the exhaust of a typical diesel engine burning heavy fuel oil (compression ignition engine) include nitrogen oxides (NO_x), particulate matter (PM) and sulphur oxides (SO_x). Thanks to the high efficiency resulting from the high temperature of combustion, emissions of carbon monoxide and unburned hydrocarbons are low. A dual fuel engine in gas mode has low nitrogen oxide (NO_x) emissions and emits some hydrocarbons (HC) and carbon monoxide (CO) emissions.

6.1.10.3.1 Abatement of particulate emissions

When burning heavy fuel oil, the particulate matter mainly consists of the ash content from the fuel oil and to a smaller extent of soot, hydrocarbons and sulphates. When burning light fuel oil, the particulate matter mainly consists of soot and HCs. Secondary cleaning equipment for particulates is currently under development for larger diesel engines. Due to the different temperature and oxygen content of the diesel flue-gas, the electrical properties of the diesel particulates (e.g. resistivity, etc.) are different compared to particulates from a boiler flue-gas, and proper testing of the ESP (electrical precipitator) is needed prior to commercial release. Highly viscous and high sulphur oils are combusted in boiler LCPs. In combination with SO_2 wet scrubbing at these LCPs, the wet ESP technique is applicable as a pretreatment for particulate removal.

A fabric filter (bag filter) needs a protection layer on the surface in order to achieve a sufficiently high reduction rate of particulates. When burning oil, this layer is thin and the performance of the filter is not efficient.

6.1.10.3.2 Abatement of SO_2 emissions

The sulphur oxide emission is related to the fuel (proportional to the sulphur content of the fuel). The primary method to reduce the SO_x emissions is to use a fuel with a lower sulphur content, whenever commercially available.

There are only a few DESOX installations which already exist in connection with diesel engines, and most of these are small or medium sized plants with only limited running experience. It must also be noted that a diesel flue-gas differs from a boiler flue-gas, for instance it has as a high oxygen content which might have an impact on the reactions in the DESOX. The investment cost for a DESOX plant varies a lot according to the chosen method. The operating cost mainly depends on the amount and type of reagent, water, electricity consumptions, maintenance and end-product disposal costs. The DESOX system needs proper maintenance in order to work optimally. Also it is bulky and consequently additional space is needed for the power plant. It must also be noted that due to the high specific flue-gas flow of a diesel engine (lambda typically about 2.7) the size of the DESOX will be relatively big.

Most of the DESOX references in diesel power plants so far are wet scrubbers using a NaOH (about 50 wt-%) water solution as the reagent. The flue-gas is washed with the reagent water solution and the SO_2 is removed. The main components of the system are the reagent storage tank and transportation system, a scrubber with recirculation pumps and an oxidation tank.

Some of the advantages of a wet scrubber using NaOH water solution as the reagent are:

- simplicity
- reliability (no clogging risk)
- good SO_2 removal efficiency
- lower investment costs compared to other DESOX methods (end-product treatments costs are not considered, nor is reheat considered (depends on the applicable legislation).

Some of the drawbacks are:

- expensive reagent
- moderate flue-gas particles reduction
- low exhaust gas temperature (detrimental for flue-gas dispersion)
- high water consumption
- high discharge water flow ('by-product').

In larger diesel power plants, other DESOX methods are often more competitive than the NaOH-DESOX (many engine units can be connected to the same DESOX unit, and consequently the relative investment costs decrease), due to lower operating costs (cheaper reagent, etc.). All DESOX methods need a large amount of make-up water and produce a large amount of end (by)-product, which has to be disposed of in an environmentally sound way. The disposal options for the by-product depends on local and national standards and on the existing infrastructure. These are, therefore, decided on a case-by-case basis.

6.1.10.3.3 Abatement of NO_X emissions

Cost effective and technically suitable primary and secondary exhaust gas cleaning technologies are the focus of today's product development. The application of primary methods to reduce air emissions at source is generally preferable to the trying to remove them after formation from the exhaust gas, often at great expense. During the last decade, NO_X emissions from large liquid fuel-fired diesel engines have been reduced considerably by primary measures as a result of extensive R&D work on the engine, whilst maintaining its high efficiency. Some measures include:

- primary methods for liquid fuel-fired diesel engines, such as a base engine optimised for low NO_X, fuel injection retards, the addition of water (water injection directly into the combustion space or water-in-fuel emulsion or humidification of the combustion air)

- the dual fuel engine (in gas mode) often uses the 'lean burn' technique and as a consequence the NO_X emission is low

- a secondary method applicable for diesel engines, i.e. SCR (Selective Catalytic Reduction).

According to the point mentioned above, the technical measures to reduce NO_X emission can be divided into primary measures and exhaust gas treatment.

Low NO_X combustion concept: One element of the 'low NO_X combustion' concept is the very late fuel injection timing. In this injection retard method, the burning temperature peak is lowered. Initially, the drawback of this method was the increased specific fuel consumption, so to re-establish low fuel consumption, the compression ratio of the engine was increased as a countermeasure, resulting in lower NO_X emissions and no penalty in terms of fuel consumption.

Very late fuel injection timing in combination with a high compression ratio demands a sophisticated modified injection rate as well as costly development of combustion chamber shape design. Sophisticated fuel injection equipment is consequently a key element in this technique. The continuing technological development of the diesel components has made it possible to further optimise the diesel cycle with the 'Miller concept'. In this concept, some components have been further developed, such as the turbocharger, fuel injection pumps, fuel injection nozzles and the camshaft.

Using the low NO_X combustion concept in combination with the Miller concept, NO_X has been reduced by up to about 40 % in today's engines compared to the same engine type at the beginning of 1990s, whilst maintaining high efficiency.

Retarding the start of the injection to reduce the firing pressure is a simple way of reducing NO_X emissions. It reduces the peak combustion temperature level and the combustion process progressively moves into the expansion process. For a modern engine, NO_X reduction by this method is around 10 %.

Engine speed: The emission of NO_X depends on the engine speed. Fuel efficient, large bore, low speed engines tend to have higher NO_X emissions than faster running smaller engines. When the engine speed is lower, NO_X concentrations are higher in the combustion chamber because of the longer time available to form NO_X.

Applying exhaust gas recirculation: Exhaust gas recirculation (EGR) can also be a method for reducing NO_X emissions from large bore engines but it requires solving certain problems associated with the cooling and cleaning of the exhaust gas before it is circulated in the engine. The recirculated gases mainly consist of carbon dioxide, nitrogen and water vapour, which helps to reduce the combustion flame temperature. The clean-up of the exhaust gas leads to an acidic, dirty and oily sludge which must be disposed of and treated. Any traces of sulphuric acid left in the cleaned gas may attack the turbocharger compressors and air coolers. For an EGR up to 15 %, a NO_X reduction of up to 50 % has been reported. However, the above-mentioned problems need to be taken into account by the application of EGR.

Injection of a fuel/water emulsion: NO_X reductions can be obtained by adding fresh water to the fuel and emulsifying the mixture before supplying it to the engine. The fuel/water emulsion is injected through the existing injection pump. The quantity of water injected depends on the operating conditions. A programmed control unit manages the mixing procedure. This method brings the water to exactly where it is needed and optimises the amount of water injected. This amount is limited by the capacity of the engine's injection device. The inert gas effect of the water in the combustion chamber lowers the combustion temperature, which then reduces NO_X production and also the thermal load of the components in the exhaust gas flow. The associated fuel consumption penalty ranges from up to 1 % increase for each 10 % water injection (related to the fuel consumption). The NO_X decrease is almost linear with increasing water injection. It is possible to decrease NO_X emission by 20 – 30 %. This solution might also influence the remaining harmful components in the diesel exhaust gas, reductions in unburned emissions such as CO and HC have been reported when operating on gasoil using this method. The quality of the emulsion is important since vapour bubbles in the heavy fuel reheating can damage the injection system.

Direct water injection: Direct water injection may be applied as an alternative to emulsified fuels. Depending on the engine type, up to about 40 – 60 % NO_X reduction is achievable. Direct water injection can only be applied on some liquid fuel fired engine types, this technique is used in some shipping installations only. Fuel consumption increase and the amount of water needed depends on the NO_X reduction rate. This method requires greater modifications to the engine design, due to the need for an additional water injection system and supervision of this system. The amount of water that can be injected is independent of the fuel injection pumps, allowing larger quantities of water to be injected. Corrosion can occur on cylinder heads and pistons, thus increasing maintenance needs.

Humid air injection: Humid air injection mainly consists of a heat-exchanger and humidification cell, which can possibly replace the intercooler. Air, which is relatively hot and dry, is fed into the unit, where the water partly evaporates, reducing the scavenging air temperature. The air fed to the cylinder is nearly saturated in water vapour: the quantity of water absorbed by the engine is controlled by the scavenge air temperature which depends mainly on the water temperature. With this method, a water quantity of about twice the corresponding fuel consumption can be absorbed by the engine. The use of seawater instead of treated water for such devices has been reported without negative effect as regards the plant reliability. This point is particularly interesting for plants located in coastal areas, as the operating cost of such a system is reduced. According to experiences of using humid air injection on engines in France, the maintenance costs decrease, the combustion chambers are cleaner and the lubricating oil consumption decreases as well. NO_X emissions reduced by 70 % have been reported on a medium speed engine.

A high NO_X reduction leads to higher emissions of unburned compounds (CO, HC, smoke etc.). Tests have shown that in practical applications NO_X reductions of up to 50 % is reasonable in order to have acceptable emissions of unburned compounds (CO, etc.). The effects also lead to a beneficial temperature drop, the amount depending on the turbo-charger pressure and how much water vapour is to be added to the combustion air. The air mass through the engine is slightly increased by the water vapour without any additional compression work being needed. Corrosion can occur on valves, pistons and air receivers, thus increasing maintenance needs and costs. Therefore, long term tests are needed in order to estimate the effects of corrosion and possible remediation options.

SCR: To date, several hundred engines in power stations and co-generation plants in Europe, Asia and the US are equipped with SCR. They operate with various grades of liquid fuel, ranging from diesel or fuel oil to low grade heavy fuel oil (180 cSt, 5% S) or residual fuels or even orimulsion. An SCR can be equipped with an additional oxidation layer for the reduction of CO and NH_3, but this is not recommended when operating on liquid fuels (such as HFO) containing sulphur. An oxidation catalyst will oxidise a part of SO_2 to SO_3 and as a consequence additional particulate is formed (sulphate). A larger diesel engine has low emissions of unburned (CO, HC). When the NO_X reduction rate is up to 85 – 90 %, the SCR system can be controlled by a simple control system, with higher NO_X reduction rates, complicated reagent premixing and injection systems and a more advanced control system are needed. Operators of large diesel engines for power generation often have the task of reducing CO, HCs and particle emissions, as well as NO_X. Often noise pollution must be reduced through the use of silencers. SCR systems including oxidation catalysts bring with them the advantage of being able to address all of these issues in one system. In addition to reducing NO_X emissions by up to 90 %, an 80 – 90 % reduction in CO and hydrocarbons, a 30 % reduction in particulate matter and a noise reduction 8 – 10 of dB(A) can be expected for average engine power.

Generally, the reduction agents used in the SCR systems are an aqueous NH_3-solution of about 25 wt-% or an about 40 wt-% urea water solution of about 40 wt-%. In some installations pure ammonia (100 %) is used (mainly due to the price). For applications with varying loads, the engine emissions are measured at different load levels during commissioning. The measured emissions values are then entered into the system controls which ensure that the reduction agent is injected into the exhaust gas stream in the correct quantities for varying NO_X levels. The catalyst type and the SCR reactor size are tailored to the pressure drop constraints of each particular application so that engine performance is not affected [167, Rigby, et al., 2001].

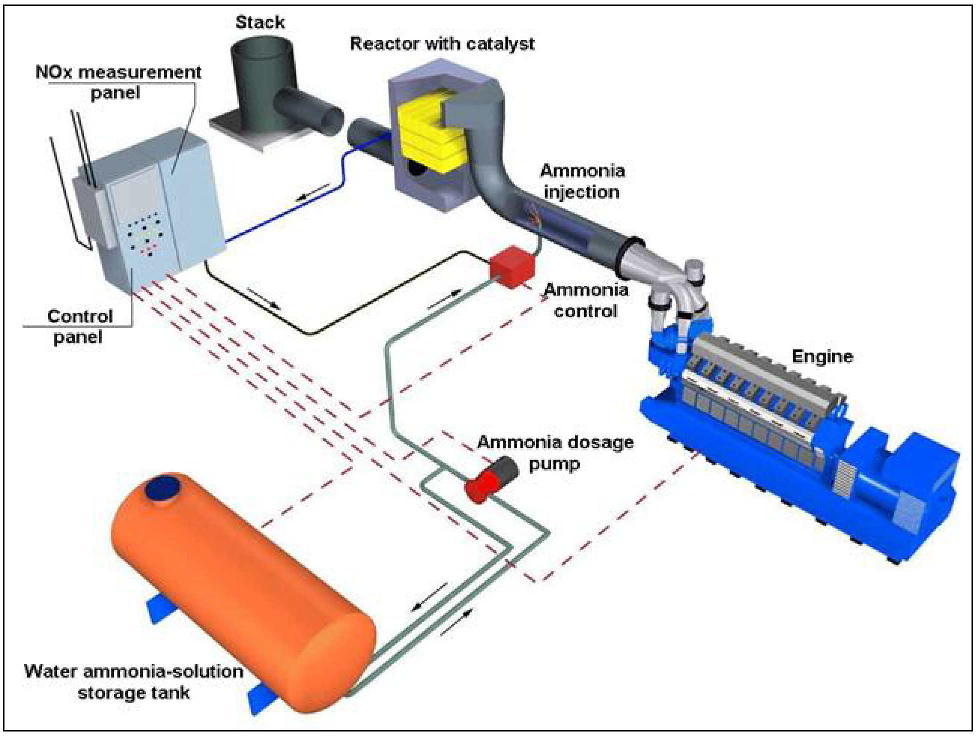


Figure 6.3: SCR system applied to a stationary engine combustion plant
[97, Euromot, 2000]

When considering the applicability of SCR in diesel power plants the following four points must be considered:

- firstly, focus should be put on the exhaust gas temperature in order to avoid salt formation on the catalyst elements. A certain minimum flue-gas temperature, which depends on the sulphur content of the fuel, has to be maintained. Some trace metals which might be present in the fuel can act as ‘catalyst poisons’ and, therefore, the ash content of the fuel to be used should preferably be analysed before the method is installed if low grade heavy fuel oil is utilised. Most diesel plants today equipped with SCR run on low sulphur oils or natural gas. Experience has shown that when operating on heavy fuel oil or other residual fuels, a soot blowing sytem is to be installed in the SCR reactor in order to keep the elements clean and avoid pressure drop increases over the SCR

- secondly, by using urea the transportation and storage risks associated with ammonia can be minimised. In some places, the supply of reagent may be limited by the lack of proper industrial infrastructure

- thirdly, the SCR technology has high capital and operating costs. Each engine has, in general, to be equipped with its own SCR unit due to technical reasons. Operating costs depend on the amount of reagent needed and on the frequency at which the catalytic elements need to be replaced or newly added to maintain the design efficiency of the SCR (after a few years of operation). The used catalytic elements need to be properly disposed of

- finally, the SCR system is recommended to be subject to regular planned maintenance or inspection, e.g. annually, in order to prevent ammonia slip. For instance, with high ammonia ‘slips’ harmful salt deposits can occur on the internal surfaces of the components sited after the reactor, such as, for example, on the boiler.

6.1.10.4 Control of emissions to air from liquid fuel-fired gas turbines

6.1.10.4.1 Abatement of SO_2 emissions

Switching to low sulphur oil or co-combustion of oil and gas might be techniques that can make a significant contribution to the reduction of SO_2 emissions. The sulphur content of light fuel oil used in gas turbines is determined by the relevant Directive 93/12 (relating to the sulphur content of certain liquid fuels valid in the EU), and should be below 0.05 %. This very low sulphur content ensures insignificant emission levels of SO_2 from gas turbines fuelled by light distillate oil.

6.1.10.4.2 Abatement of NO_X emissions

NO_X formation can be restricted by decreasing the combustion temperature. This is accomplished by the pre-mix burner technique, where fuel is blended with the combustion air in order to avoid excessive peak flame temperatures. This, however, only operates when the unit is operating near full load. A different combustion method must be applied for part-load operation, start-up and shutdown, in order to avoid flashbacks. Steam injection and water injection are also used to reduce combustion temperatures and consequently NO_X.

Applying stage combustion in gas turbines at lower temperatures needs a different design of gas turbines as two pressure stages with separate fuel supplies are needed.

Wet reduction processes: Water or steam is injected into the combustion chambers in order to reduce the combustion temperature, thus avoiding the formation of thermal NO_X. For gas turbines (GT) operating in the ‘open cycle’ system, water is used for injection, whereas for GTs operating in a ‘combined cycle’ or co-generation system, steam is more often chosen for the injection.

Some gas turbine combined cycle plants in Europe, particularly in Austria, France, Germany, Italy, and the Netherlands, have also applied **SCR systems** to reduce NO_X emissions. In the US, SCR is commonly used for gas turbines, including those operated with liquid fuels.

6.1.11 Water and waste water treatment

The techniques described for waste water treatment in Chapter 3 are, to a large extent, applied for the purification of waste water from liquid fuel-fired plants (boilers, gas turbines and stationary engines).

Water treatment for oil-fired LCPs has no special requirements. Demineralised water is required to compensate for the blowdown water from the drums and water or steam leakage. The quality of the water has to fulfil the requirements of the boiler manufacturers and therefore water treatment is required. Usually demineralisation is sufficient to meet these requirements.

For the gas turbine and the HRSG, demineralised water is required for the following purposes:

- as make-up water for the HRSG, to compensate for the blowdown water from the drums. If steam or water injection is applied, the water loss has to be compensated for by adding make-up water. The quality has to fulfil the manufacturers requirements and, therefore, water treatment is usually required. Usually demineralisation is sufficient to meet these requirements
- water injection for NO_X abatement (approximately 1 kg water to 1 kg fuel). In France, for instance, the water injection is between 50 and 100 % of the total fuel flow
- for washing the gas turbine compressor, demineralised water is usually used. For online washing, condensate from the water/steam cycle is sometimes used, but more often demineralised water is supplied to a separate water wash unit. For offline washing, a detergent is added to the demineralised water to improve the washing effect.

Operation of the gas turbine and the HRSG (if applied) leads to the following waste water:

- blowdown water from the boiler circulation system. This is water that was used to maintain the quality of the boiler water. The boiler water usually contains additives to protect the boiler from corrosion, such as ammonia, sodium hydroxide and/or phosphates. In practice, this blowdown water is quenched and discharged to sewerage systems or to a water treatment plant if the water does not meet the permit requirements
- waste water from the gas turbine water washing processes can be discharged or has to be considered as chemical waste, depending on the detergents used in the washing and on the materials for disposal from the compressor
- water which is contaminated with oil or oil containing fluids. This is usually collected into a system and treated separately in a water treatment plant
- remaining waste water from the plant, such as scrubbing water. This is normally discharged to the domestic sewerage system.

An engine driven power plant usually preserves its water. The cooling circuits contain about 20 to 30 % of the input fuel energy. The cooling circuit energy must be cooled away, if it cannot be utilised in some other CHP process. A single cycle 130 MW_e oil-fired diesel power plant equipped with cooling towers typically consumes about 220 m^3/h of raw water, compared to a similar size coal/oil based thermal steam turbine plant with cooling towers consuming up to about 500 m^3/h of raw water (no DESOX is considered in the above figures). Air-cooled radiators are very suitable for engine driven plants and if the example 130 MW_e heavy oil-fired diesel plant is equipped with radiators, the make-up water needed (mainly for fuel oil and lube oil separators, make-up water for the engine cooling circuit, turbo wash-water, etc.) is typically in the order of up to only 5 m^3/h.

A result of the lower water requirement is a smaller discharge of waste water, and consequently less thermal pollution of the surrounding watercourse. Another consequence is a lower usage of different water purification chemicals on-site and a reduced risk, therefore, of chemical spillages. Traditional techniques are used in the treatment of the waste water.

6.1.12 Combustion residues and by-products treatment

Oil treatment includes centrifugal separation units and modules, filters, combined cleaning units, and complete fuel conditioning systems. An oil recovery and sludge treatment system by flotation and precipitation is integrated in this treatment system. The oil or fuel recovered is burned in an auxiliary oil-fired boiler.

Final sludges are dewatered, dried, solidified and incinerated, or disposed of by authorised contractors. Water from sludge dewatering, which is contaminated with oil or fluids containing oil, is usually collected in a specific system and discharged separately. Sludge is also collected from the treatment of washing effluents from the air preheaters, boilers from the flue-gas side and from other equipment.

6.2 Examples of applied processes and techniques

This part of Chapter 6 provides a number of examples of techniques and processes currently applied in different liquid fired combustion installations. The aim of the examples is to demonstrate how specific techniques have been applied to new or retrofitted plants in order to ensure a high level of protection for the environment as a whole, taking into account, in each case, the particular site-specific conditions and environmental requirements. However, from the information collected, it is not always clear, if or how each technique described in the examples has been assessed against the definition of BAT given in article 2 (11) of the Directive, as well as against the list of 'considerations to be taken into account generally or in specific cases when determining the best available techniques bearing in mind the likely costs and benefits of a measure and the principles of precaution and prevention' and, consequently, how the technique has been selected and applied. Furthermore, it cannot be assured that the environmental performance presented is constant and continual under all operational conditions, over which time period, whether any problems have been encountered, and what the cross-media effects are. Also, it is not always clear what the driving force is for applying the technique and how the costs and environmental benefits are related in each case. Therefore, the information provided in the following examples is meant only to provide general indications of reported current practice and cannot be considered as appropriate reference points. The techniques that are given as examples arise from information provided and assessed by members of the Technical Working Group as part of the information exchange of LCPs.

6.2.1 Individual techniques to reduce emissions from liquid-fuel-fired large combustion plants

EXAMPLE 6.2.1.1 ADVANCED CONTROL OF LOCAL COMBUSTION CONDITIONS FOR NO_X REDUCTION AND BOILER PERFORMANCE IN FUEL OIL AND ORIMULSION-FIRED BOILERS

Description: The boiler efficiency and NO_X generation in industrial boilers depend largely on the correct distribution of fuel and air in the furnace. The presented control technology relies on the combination of local combustion balancing strategies and the implementation of advanced combustion monitoring systems. This allows the application of stricter combustion controls for solving these common situations of imbalanced combustion scenarios. The system allows gas concentration measurements to be taken in any interior area of the furnace of industrial boilers, especially near the burners. This makes it possible to achieve not only important improvements in performance monitoring and consequently performance (i.e. boiler efficiency, NO_X emissions, slagging, auxiliaries consumption), but also leads to a safer and more flexible operation of industrial boilers. For more detailed information about this technology, see also the example technique in Section 4.2.1.

Applicability: Applying a new measurement system inside the furnace of industrial boilers enables the openings to be placed in any location required, with their placement no longer being limited to those inspection ports included in the original design of the boiler. In this way, it is possible to take measurements at the level of each burner in the boiler, without any significant structural modifications to the unit. Therefore, the presented control technology can be applied to both existing plants and new installations. Table 6.1 shows the main characteristics of four existing fuel oil- and orimulsion-fired combustion plants where this advanced control technology is currently being applied. These plants are located in Spain and Italy.

Plant	Boiler Design	Capacity (MW_e)	Burners distribution	Type of fuel	Atomisation
A	Front	40	2 vertical levels (3 burners per level)	Fuel oil	Steam
B	Front	40	2 vertical levels (3 burners per level)	Fuel oil	Air
C	Front	60	3 vertical levels (2 burners per level)	Fuel oil	Steam
D	Tangential	320	5 vertical levels (4 low-NO_X burners per level)	Orimulsion (coal retrofitted)	Steam

Table 6.1: Application of the presented advanced control technology in oil-fired boilers

Achieved environmental benefits: The application of this technology led to NO_X reductions of around 30 %, and at the same time minimised CO emissions. This also led to substantial improvements in the overall plant performance (i.e. in particular in the reduction of steam regulation needs and in the control of SO_3 generation).

Operational data: The optimisation was based on:

- adjustment of the overall excess oxygen, whilst maintaining an adequate local stoichiometry for each burner
- adjustment of the flame type (based on appropriate control of the air inputs)
- identification of the optimum number of active burners for each operating load.

All of these adjustments were made under the premise of appropriate control of the individual operational conditions of each burner, based on the local combustion measurements.

Cross-media effects: In addition to the direct environmental benefits mentioned above, an advanced control of local combustion conditions offers several other advantages such as less fuel required (see also example in Section 4.2.1).

Economics: The investment of this technological approach is currently in the range of EUR 300000 to 700000, depending on the particular characteristics of the unit under consideration (capacity, design, baseline operation, etc.).

Driving force for implementation: Besides reducing the fuel costs and the control of NO_X formation, the main reasons for the application of this technique are the ability to optimise the heat rate or slagging by adjusting the oxygen and temperature distributions within the furnace.

Reference literature: [176, Cañadas and et al, 2001], [177, Rodríguez and et al, 2002], [178, ECSC, 2001].

6.2.2 Improving the environmental performance of existing large liquid-fuel-fired combustion plants

EXAMPLE 6.2.2.1 HEAVY FUEL OIL-FIRED BOILER WITH RETROFITTED FLUE-GAS TREATMENT

Description: Two identical units have a gross power production capacity of 2 x 420 MW_e and a net electrical capacity of 2 x 386 MW at a rated thermal input of 2 x 1007 MW. Crude oil is transported via pipelines to the nearby refinery where heavy fuel oil is produced. The plant was commissioned in 1965 and retrofitted with flue-gas treatment installations in 1990 and 1994. These comprise a wet desulphurisation with a separation efficiency of >90 %, and an SCR installation in a high dust position with a removal efficiency of >70 %. Furthermore, lining the inside of the 180 m high stack with GRP (glass reinforced plastics) reduced the emission of acid particles and dust. The boiler (‘Benson’, two-draught) is equipped with 14 low NO_X burners (bottom firing), overfire air, and combustion air preheating. The oil is stored in five tanks with a total volume of 340000 m^3. Two of the tanks are isolated for storing warm oil. The electrostatic precipitator (ESP) and the wet flue-gas desulphurisation (FGD) together reduce the dust content of the flue-gas by at least 80 %.

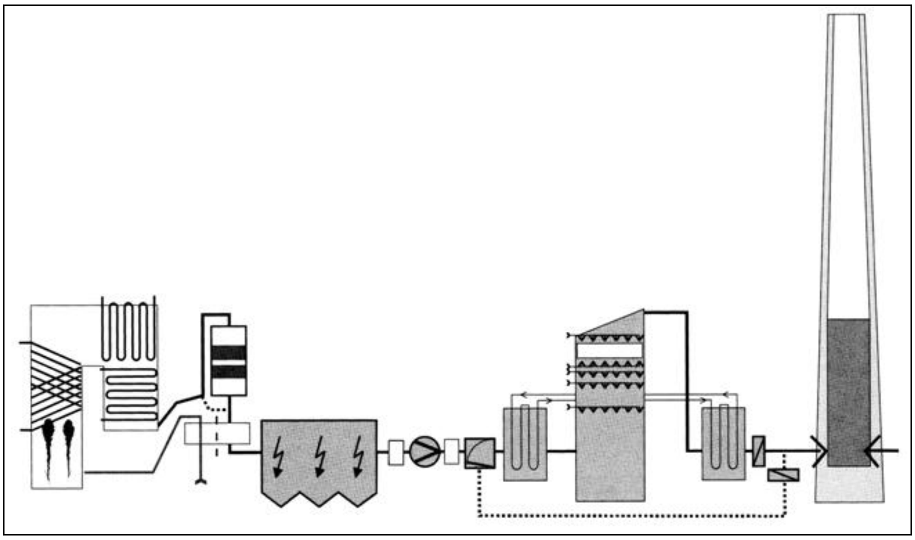


Figure 6.4: Retrofitted heavy fuel oil-fired power plant with SCR, wet FGD and a heat displacement system

Achieved environmental benefits: The retrofitted flue-gas treatment allows comparatively low concentrations of SO_2 and NO_X to be achieved in the clean gas. Retrofitting the stack strongly reduced the impact of acid particles in the plant neighbourhood.

Applicability: The secondary flue-gas treatment can be added to existing heavy fuel oil-fired boilers. Retrofitting the stack for acid particulate emissions control depends on local conditions. Here, the concentration of SO_3 in the clean gas is the most important parameter, as it is soluble in water and can condense on the walls of the stack. This highly acidic fluid is then transported into the adjacent environment. In general, the concentration of SO_3 in flue-gases is reduced by only 20 – 30 % in the wet FGD system. On the other hand, the FGD lowers the temperature of the flue-gas and the water vapour content increases. These two effects boost the condensation of acid in the stack.

Cross-media effects: Fly ash results from the ESP operation. The wet FGD produces waste water and gypsum. The operation of the flue-gas treatment reduces the electrical net efficiency of the plant.

Operational data: In 1998, the first unit produced 443.5 GWh_e of net electricity during 1544 hours, and the second one 299 GWh_e during 1017 hours in operation. The annual electrical mean net efficiency amounted to 36.7 %, and 961 equivalent full load hours were achieved.

	Monitoring	Measured emission levels (mg/Nm^3) (annual mean value at 3 % O_2)		Specific emissions (g/MWh$_e$)	
		Unit 1	Unit 2	Unit 1	Unit 2
O_2 content (%)	Continuous	4.5	4.5		
Flue-gas volume flow rate (10^6 m^3/h)	Continuous	1.3 (Full load)	1.3 (Full load)		
Dust (mg/Nm^3)	Continuous	10	15	20.5	30.2
SO_2 (mg/Nm^3)	Continuous	50 – 250	50 – 250	52	235
NO_X (mg/Nm^3)	Continuous	121	131	331	355
CO (mg/Nm^3)	Continuous	50	50	20.5	20.7
HCl (mg/Nm^3)	Discontinuous	0.2[1]	0.1[1]	0.08	0.04
HF (mg/Nm^3)	Discontinuous	<0.1[1]	<0.1[1]	<0.04	<0.04
NH_3 (mg/Nm^3)	Discontinuous		<0.1[1]		<0.04

Notes:

[1] Mean value of individual results

Table 6.2: Atmospheric emissions in 1998

The amount of heavy fuel oil fired was 179 kilotonnes, which means a specific consumption of 0.242 kg/kWh$_e$. The sulphur content of the fuel was 3.5 % and the ash content 0.056 %.

Auxiliary material	Consumption (t/yr)	Specific consumption (g/MWh$_e$)
HCl, (30 % solution)	122	160
NaOH, (50 % solution)	27	36
Slaked lime	20	27
Crushed limestone	13811	13500
$FeCl_3$, (40 % solution)	14	19
NaOH, (25 % solution)	7.5	10
NH_3,	458	620
Light fuel oil	2952	4200

Table 6.3: Consumption of important auxiliary supplies in 1998

The once-through cooling system needed 97.15 million m^3/yr, which is equivalent to a specific demand of 100000 m^3/h at full load. Waste water is produced during the regeneration of the full water softening installation. The annual mean flowrate of this water was 12 m^3/h. The average AOX concentration is <1 mg/l, which is equivalent to <0.015 g/MWh$_e$. After adjustment of the pH-value, this waste water is released to the receiving water. Another major source of waste water is the wet FGD. The mean value of the waste water flowrate at full load is 23 m^3/h. The waste water is treated and then discharged to the receiving water with mean concentrations of impurities as shown in Table 6.4.

	Mean values	Number of measurements as a basis for mean values	Mean specific load (g/MWh$_e$)
pH value	9.2	77	
COD (mg/l)	27.9	27	0.83142
N_{total} (mg/l)	85	1	2.533
Zn (mg/l)	0.01	13	0.000298
Cr (mg/l)	<0.1	1	<0.0003
Cd (mg/l)	<0.005	27	<0.00015
Cu (mg/l)	<0.1	1	<0.0003
Pb (mg/l)	<0.1	1	<0.0003
Ni (mg/l)	0.028	4	0.0008344
V (mg/l)	0.03	27	0.000894
Filterable matter (mg/l)	7.3	77	0.21754
Sulphate (mg/l)	2130	27	63.474
Sulphite (mg/l)	<20	(only at plant start-up)	<0.6
Fluoride (mg/l)	3.3	11	0.09834
Hg (mg/l)	0.002	27	0.0000596
Toxicity for fish	<2	(only at plant start-up)	
Note: Data from 1998			

Table 6.4: Concentrations of impurities in the waste water from the desulphurisation plant after treatment

To reduce emissions from the waste water, the water from the regeneration of the cationic demineralisation for the condensate is injected into the boiler. Combined operation, which means the simultaneous blending of oxygen and ammonia, allows for a lower ammonia concentration in the water-steam circuit. Thus, the regeneration rate for the filters of the demineraliser is reduced, which means a decreased water demand. Changing the resin of the ion exchanger in one of the full water softening installations could reduce the water consumption for regeneration. A further reduction in water demand can be achieved by recirculating the condensate and by partially recirculating the filtrate from the gypsum dewatering into the FGD circuit.

	Insulation	Boiler ash	Fly ash	Gypsum and gypsum briquettes
Quantity (t/yr)	12.4	17.7	113.8	1767
Specific quantity (kg/MWh$_e$)	1.08	0.0018	0.0118	1.8
Utilisation/disposal	Recycling	Mine fill	Mine fill	Gypsum and concrete industry

Table 6.5: Residues generated in 1998

The emission limit values for sound depend on nearby residential sites, which in this case are situated at a distance of 530 – 1200 m. Measures to reduce sound emissions comprise sound proof security valves and overhead noise barriers. Noise levels at the residential sites reach values between 26 and 46 dB(A).

Economics: The investment for the flue-gas control techniques (wet FGD and SCR) amounted to EUR 25 million in total (between 1990 and 1994).

Driving force for implementation: The retrofitting with wet FGD and SCR resulted from the imposition of more stringent emission limit values. The lining of the stack with GRP was necessary due to complaints about acidic deposits. However, applying the new material led to a decrease in the stack corrosion and thus reduced operating costs (e.g. from lower maintenance).

Reference literature: [98, DFIU, 2001].

EXAMPLE 6.2.2.2 PEAK LOAD POWER PLANT CONSISTING OF A BOILER AND GAS TURBINE FIRED WITH LIGHT FUEL OIL, OPTIONAL COMBINED CYCLE OPERATION

Description: The example peak load power plant consists of a gas turbine (260 MW_{th} rated thermal input, 60 MW_e electrical power) and a boiler (838 MW_{th} with fresh air and 655 MW_{th} in combined-cycle operation). The steam turbine generates up to 265 MW_e. In combined cycle operation, the flue-gas of the gas turbine is used as combustion air in the boiler. The power plant was commissioned in 1972 for the firing of heavy fuel oil and was upgraded by a retrofit in 1993 for light fuel oil firing. In 1994, the boiler and the gas turbine were both equipped with a water injection system. Additionally, the burner and the combustion chamber of the gas turbine were exchanged. Demineralised water was injected into the system by lances equipped with cone-shaped nozzles, at pressures between 3 and 22 bar. The water consumption rose to 50 m^3/h for the boiler and 18.7 m^3/h for the gas turbine at full load operation.

Achieved environmental benefits: The injection of water reduces the emissions of NO_X from the gas turbine as well as from the boiler.

Applicability: The injection of water is mainly applied when the NO_X emissions of existing light oil fired plants must be reduced.

Cross-media effects: The primary measure used to reduce NO_X emissions produced neither residues nor waste waters, but consumed large amounts of demineralised water. Furthermore, the electrical efficiency of the whole plant was reduced, as the enthalpy, which has to be spent to effect the vaporisation, remains in the flue-gas and is not re-used. The treatment of the feed-water and the condensate produces sludge and waste water.

Operational data: In 1998, 6976 MWh_e (gross) were produced by the steam turbine and 118 MWh_e (gross) by the gas turbine. The plant was in operation for 74 hours and thus was only used to cover peak loads. Table 6.6 and Table 6.7 summarise the atmospheric emissions in 1998.

	Measurement	Measured emission level (daily mean value at 3 % O_2)	Specific emissions (kg/TJ_{fuel})
O_2 content (%)	Continuous	3	
Flue-gas volume flowrate (m^3/h)		853523	
NO_X (mg/Nm^3)	Continuous	143.3	40.5
CO (mg/Nm^3)	Continuous	4.77	1.35

Table 6.6: Atmospheric emissions from the boiler (single operation) in 1998

	Measurement	Measured emission level (daily mean value at 3 % O_2)	Specific emissions (kg/TJ_{fuel})
O_2 content (%)	Continuous	3	
Flue-gas volume flowrate (m^3/h)		965000	
NO_X (mg/Nm^3)	Continuous	259.7	76
CO (mg/Nm^3)	Continuous	129.8	38

Table 6.7: Atmospheric emissions for a combined cycle operation in 1998

2012.1 tonnes of light fuel oil were fired in the boiler, and 47.9 tonnes in the gas turbine. The once-through cooling system needs about 40000 m^3/h of water from the adjacent river at full load operation. The effluent of the primary cooling system and the waste water from the condensate treatment are dumped to the sewer. Waste water from the feed-water treatment (250 m^3/h at full load) is dumped to the river after neutralisation. The concentrations of impurities in this waste water are summarised in Table 6.8 for the year 1998.

	Results from individual measurements (1998) (mg/l)
AOX	0.023 – 0.039
COD	10 – 23
P	0.12 – 0.2
N	42 – 45
Zn	0.078
Cr	0.0038
Cd	0.0003
Cu	0.0044
Pb	0.0053
Ni	0.0036

Table 6.8: Concentrations of impurities in the neutralised waste water from feed-water treatment

The main residues are used lubricants and sludge form the water treatment.

Economics: Total investment for the retrofitting of the plant (water injection, new burner and combustion chamber for the gas turbine) amounted to EUR 12.8 million, of which EUR 10.25 million was for retrofitting the gas turbine and the rest was needed for the boiler.

Driving force for implementation: The water injection system was added to comply with emission limit values.

Reference literature: [98, DFIU, 2001].

6.2.3 Environmental performance of new liquid-fuel-fired combustion plants

EXAMPLE 6.2.3.1 HEAVY FUEL OIL/NATURAL GAS-FIRED COMBINED GAS TURBINE-STEAM TURBINE – DISTRICT HEATING POWER PLANT WITH FLUE-GAS CLEANING

Description: The example power plant was designed as a combined gas turbine-steam turbine-district heating plant to run on low sulphur-content heavy fuel oil and natural gas. A schematic layout of the plant is shown in Figure 6.5.

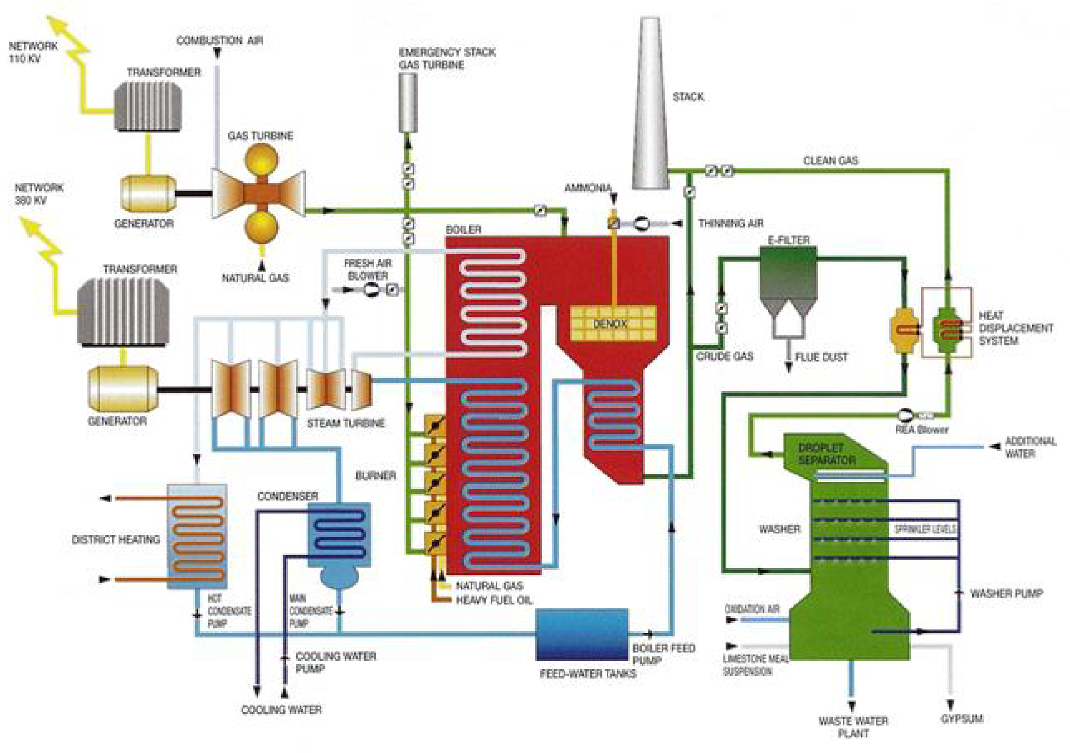


Figure 6.5: Combined gas turbine-steam turbine-district heating power plant burning heavy fuel oil and natural gas
[43, Wienstrom, 2001]

The exhaust gases from the gas turbine are directed into the steam boiler, a Benson double draft forced continuous flow boiler with intermediate superheating and forced draft firing. The gas turbine exhaust gas is used as combustion air, supplying oxygen to the heavy fuel oil/natural gas low NO_X burners (20 combined heavy fuel oil natural gas staged burners; arranged in the form of a whole wall, firing at five levels).

The steam generated in the boiler is used to drive a four-stage condensation-reheat turbine with intermediate superheating. The steam turbine drives the generator which, without the off-take of thermal energy for the district heating network, has an electrical energy output of about 355 MW. With a thermal energy off-take equivalent to about 350 MW, the electrical power output is reduced to 310 MW.

Flue-gas cleaning

- denitrification with low NO_X burners, as a primary measure, followed by a high dust SCR system
- wet limestone scrubber with a forced oxidation gypsum process, for reducing the sulphur dioxide
- electrostatic precipitator (ESP), for de-dusting the flue-gas.

Achieved environmental benefits: The combination of a gas turbine, a steam boiler and a district heating system increases the overall electric efficiency, as well as the fuel efficiency. The measured emission levels are as follows.

Pollutant	Measured emission level (mg/Nm^3)	Rate of reduction (%)	Technique used
NO_X	90	>80	Low NO_X burner as a primary measure and a selective catalytic reduction (SCR) system as a secondary measure, giving an SO_2/SO_3 conversion <2 % (official requirement)
SO_2	60 – 90	96	Wet limestone scrubber with a forced oxidation gypsum process
CO	15 – 20		
Dust	10 – 30	>95	Electrostatic precipitator (ESP). Concentration of dust in the clean gas depends on the operating mode (heavy fuel oil or natural gas)
NH_3	0.1		
Note: Measures continuously measured, daily average, 3 % O_2, heavy fuel oil, full load			

Table 6.9: Overview of measured emissions

The waste water from the FGD plant contains impurities such as metals from fuel and inert material from the limestone. These impurities can be precipitated by adjusting the pH and adding flocculation agents. The sediment can then be separated. The residual slurry is transported to a chamber filter press, dewatered and then discharged.

Pollutant	Concentration (mg/l)	Specific emissions (mg/t heavy fuel oil installed combustion capacity)
As	0.001	
Pb	0.03	20
Cd	0.003	10
Co	0.002	
Cr_{total}	0.03	100
Cu	0.003	100
Hg	0.0001	10
Mn	0.030	
Ni	0.03	100
Sn	0.001	
Tl	0.031	
V	0.073	100
Zn	0.05	200
Fluoride calculated as F	0.1	
Chloride calculated as Cl	400	
Ammonia calculated as N	0.85	
Total phosphorus as P	0.150	
Total Nitrogen as N	76.6	
SO_4	1215	
Sulphide calculated as S	0.1	40
Sulphite calculated as SO_3	10.2	
TOC calculated as C	8.6	
Note: Values as daily composite sample		

Table 6.10: Measured emissions to water after treatment from flue-gas cleaning

Applicability: Gas turbines can be integrated into the design of new installations, but they may also be used for repowering existing liquid fuel-fired boilers. The flue-gas cleaning techniques, both primary or secondary measures such as low NO_X burners, SCR, ESP and wet FGD plants, are applicable to new and existing plants. Out-coupling the heat increases the fuel efficiency but needs a district heating network.

Cross-media effects: The catalyst needs to be washed with oxalic acid after 35000 operating hours. It is estimated that after 42000 operating hours (and washing after 35000 operating hours) the SO_2/SO_3 conversion is about 0.7 % and the catalytic activity 96 %. Part replacement of the catalyst is required after an estimated 70000 operating hours.

The water treatment plant of the FGD system and the dewatering of the by-product gypsum both generate waste water. Gypsum can be used in the cement and construction industry.

Operational data:

Fuel: Heavy fuel oil (2 % S, <100 ppm V, <60 ppm Ni, 40600 kJ/kg calorific value)
Natural gas (36100 kJ/kg calorific value)
Operating hours (reference year 1999):
6566.5 h producing electricity
5937.5 h district heating
Efficiency: $\eta_{el,\ net} = 45.21$ % (natural gas)
$\eta_{el,\ net} = 34.35$ % (heavy fuel oil, operation without gas turbine)
η_{total} = about 80 % (in the case of district heating)
Monitoring: Continuous measurements of: NO_X, SO_2, CO, dust, O_2, temperature and volume of flue-gas, atmospheric pressure, ambient air temperature and flue-gas volume ($1.1*10^6$ m^3/h)

Economics:

Technique	Investment costs	Operating costs
SCR	EUR 14 million total cost: including construction, catalyst, ammonia storage, pipeworks and control equipment	EUR 1.3 million/yr: including depreciation, energy requirement, staff and maintenance
ESP	EUR 1.44 million	EUR 0.64 million/yr: including fly ash disposal and depreciation
FGD plant	EUR 47.2 million: including relevant auxiliary plants	EUR 7.6 million: including depreciation, limestone and gypsum

Table 6.11: Investment and operating costs of the applied abatement techniques

Driving force for implementation: Increased electrical and fuel efficiency, as well as a reduction of air and water emissions.

Reference literature: [44, Austrian Ministry of Environment, 2000].

EXAMPLE 6.2.3.2 DIFFERENT HFO AND DIESEL POWER PLANT EQUIPPED WITH AN SCR-SYSTEM

Description: The example power plants are situated in Europe and the US. The capacity of the plants range from 21 MW_e to about 49 MW_e. The power plants use heavy fuel oil or diesel as the main fuel. Each engine or plant is equipped with its own SCR (Selective Catalytic Reduction) unit for the NO_X reduction. An additional advantage of SCR systems is its effect of reduceing other pollutants such as hydrocarbons and soot to a certain extent, and as well a sound reduction of about 8 – 10 dB(A).

Operational Data: In Table 6.12 below, the main performance parameters of HFO and diesel plants are listed.

	Plant A	Plant B	Plant C	Plant D
Location	EU	EU	EU	US
Commissioning year	1997	2002	1999	2001
Plant type	Combined heat and power (CHP) plant	Power generation	Combined Heat and Power (CHP) Plant	Power generation
Fuels	Natural gas (main), gasoil (pilot fuel and back-up	HFO (2 – 3 % S)	Diesel fuel as main fuel	Light fuel oil (oil nr. 2)
Combustion technique	2 gas diesel engines	2 HFO engines	3 dual fuel engines	30 diesel engines
Capacity	31.6 MW	34 MW	21 MW	49 MW
NO_X performance				
Secondary measure	SCR (reagent: aqueous 33 wt-% NH_3)	SCR (reagent: aqueous NH_3)	SCR (reagent: aqueous urea)	SCR (reagent: aqueous urea)
NO_X without SCR (mg/Nm^3) **at 15 vol-% O_2**	n.a.	1528	1388	1460
NO_X with SCR (mg/Nm^3) **at 15 vol-% O_2**	180 (diesel in back-up mode)	153	150	145
NO_X reduction rate over SCR	n.a.	90 %	89	90
Ammonia slip (mg/Nm^3) **at 15 vol-% O_2**	20	<2.7 fresh catalyst	<2 fresh catalyst	<2 fresh catalyst

Table 6.12: Emission levels of HFO and diesel power plants equipped with SCR

Reference literature: [147, Wärtsilä NSD, 2001], [88, Euromot, 2001], [181, Ceramics GmbH, 2002], [78, Finkeldei, 2000].

6.3 Current consumption and emission levels

6.3.1 Overview of liquid fuels used in large combustion plants

The composition of a particular crude oil is unique and cannot be precisely defined. As a rough guide, it contains alicyclic, cyclic and aromatic hydrocarbons; compounds of S, N and O; and traces of other compounds containing Ni, Fe, V, Mo, Cl, F, etc.

Heavy oils are products derived from crude oils. Thus, their composition varies with that of the source crude. They are composed entirely, or substantially, of the residuals or bottoms from petroleum refining operations, i.e. materials which remain in a condensed form in the processing. The atmospheric distillation temperature for these components exceeds 540 °C, and they appear after all the other lighter products have been removed from the refinery stream.

Some physico-chemical properties of oils are given in the following tables:

Property		Diesel oil	Light fuel oil	Heavy fuel oil	Refinery bottom product
Content of:					
carbon	%			84	85 - 88
hydrogen	%			11	8 - 12
sulphur	%	0.5	<0.2	<4	1 – 4
water	%	0	<0.02	<1.5	<0.5
sediment	%	0	<0.1	<0.25	<0.2
sodium	ppm			3 to 200	
vanadium	ppm			50 to 200	200 – 350
Kinematic viscosity (20 °C).	mm^2/s		<9.5	<9.5	
Kinematic viscosity (100 °C)	mm^2/s			<40	
Flashpoint (flammability)	°C	>55	>55	>70	
Density at 15 °C	kg/dm^3	0.85	0.87	0.95 to 1	
High heating value	MJ/kg	>46	45	43	
Low heating value	MJ/kg		42	39.5 to 41	38 - 40

Table 6.13: General characteristics of liquid fuels
[58, Eurelectric, 2001]

Property	High sulphur	Intermediate sulphur	Low sulphur
Sulphur (wt-%)	2.2	0.96	0.50
Carbon (wt-%)	86.25	87.11	87.94
Hydrogen (wt-%)	11.03	10.23	11.85
Nitrogen (wt-%)	0.41	0.26	0.16
Ash (%)	0.08	0.04	0.02
Vanadium (ppm)	350	155	70
Nickel (ppm)	41	20	10
Sodium (ppm)	25	10	<5
Iron (ppm)	13	9	<5

Table 6.14: Chemical properties of several typical heavy oils
[87, Molero de Blas, 1995]

Property	Units	Orimulsion
Density	kg/m^3 at 15 ºC	1010
Viscosity	cSt at 50 ºC	350
Water	%-vol	28 – 31
Sulphur content	%-wet	max 3 %
Ash arising	mg/kg	0.14 – 0.2
Vanadium	mg/kg	300 – 365
Sodium	mg/kg	30
Magnesium	mg/kg	6
Lower heat value	MJ/kg	27 – 28

Table 6.15: Properties of orimulsion
[97, Euromot, 2000]

The nitrogen and sulphur contents are two of the most important chemical parameters. The following graph shows the distribution of nitrogen and sulphur contents in various types of vacuum residues according to their geographical origin. This figure shows that, in most cases, it is impossible to achieve a low sulphur content and a low nitrogen content at the same time.

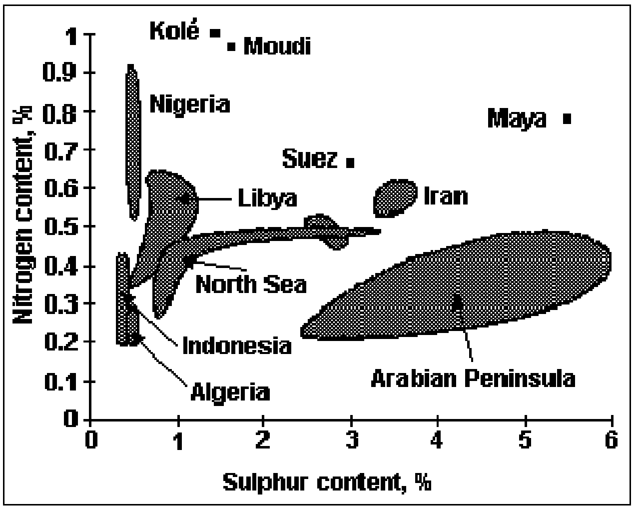


Figure 6.6: Sulphur and nitrogen contents in HFO (vacuum residues) according to their geographical origin
[87, Molero de Blas, 1995], [146, UFIP, 2001]

Of the fuel oils, heavy fuel oil (HFO) is the most important LCP fuel, whereas only small amounts of light fuel oil (LFO) are used at large combustion plants, mostly due to its high price. Light fuel oil has a low sulphur content, because sulphur is removed from it in the refinery process. In general, the use of HFO without FGD is limited by national regulations; in Finland for instance, the highest permitted HFO sulphur content is 1 %. Certain HFO qualities can have quite high sulphur contents, and in those cases, flue-gas desulphurisation (FGD) is necessary. The ash content of HFO is low, usually well below 0.2 wt-%, but particle removal from the flue-gas is needed. The oil flame temperature is high, but the oil nitrogen content is low and as a result there is only moderate NO_X formation [59, Finnish LCP WG, 2000].

6.3.2 The efficiency of liquid fuel-fired combustion plants

The boiler efficiency for a clean and new boiler using liquid fuel has currently been reported to be around 95 % (LHV). The main losses are from flue-gas waste heat at the stack, unburned carbon-in-ash and radiation losses.

6.3.2.1 Techniques to increase the efficiency of oil-fired boilers

Oil-fired boiler efficiency is closely linked with the nature of the fuel and the temperature of the ambient air. However, optimisation of some parameters is possible:

- **unburned carbon in ash:** Optimisation of combustion leads to less unburned carbon-in-ash. It should be noted that NO_X abatement technologies by combustion modification show a tendency for increasing unburned carbon
- **air excess:** The amount of excess air depends on the boiler type. Typically, 5 % excess air is common for oil-fired boilers. For reasons of combustion quality (i.e. related to CO and unburned carbon formation), corrosion, and safety, it is often not possible to further reduce the excess air
- **flue-gas temperature:** The flue-gas temperature leaving the clean boiler (depending on fuel type) is traditionally between 120 and 220 °C, to avoid acid corrosion by condensation of sulphuric acid. However, some designs incorporate a second stage of air heaters to lower this temperature below 100 °C, but with special claddings on the air heater and the stack, which makes this reduction economically restrictive.

6.3.2.2 Energy consumption of auxiliaries

The energy consumption of auxiliaries depends on a number of parameters:

- **level of pollution control:** advance FGD consumes more energy and pollution control generally has a detrimental effect on efficiency
- **design of auxiliaries:** boiler auxiliaries have to be over dimensioned to withstand all variations in parameters in comparison with design values (possible leaks, alternative fuels, start-up needs, redundant systems, etc.). These technical options lead to non-optimum auxiliary energy consumption under nominal conditions and design fuel.

6.3.3 Emissions to air

6.3.3.1 Emissions to air from liquid fuel-fired boiler plants

Combustion Technique	**Capacity**	**Emission Reduction Measures**	**Emissions to air (mg/Nm^3)**								**Remarks**
			SO$_2$	**NO$_X$**	**Dust**	**CO**	**NH$_3$**	**V**	**Ni**	**Other metals**	
Heavy fuel oil boiler	100 -300	FGD(w)/SCR/ESP	130	247	5	17					Plant contains nine units, of which one is equipped with an SNCR
	>300	FGD(w)/SCR/ESP	50 – 250	121 – 131	10 – 15	50					HCl 0.1 – 0.2 mg/Nm^3 HF 0.1 mg/Nm^3
	>300	SCR/FGD(w)/ESP	<130	<130	<5	<10	0.6				SO$_3$ 4.5 mg/Nm^3
	>300	FGD(w)/SCR/ESP	90	60 – 90	10 – 30	15 – 20	0.1				
	n.a.	No abatement has been indicated	1700	600 – 1200	30 – 1500	>50					Fuel oil with 1 % S
Light fuel oil boiler			126	1.1 – 141	1 – 3.9	1 – 14.6					
Combined cycle combustion (light oil)	n.a.	No abatement has been indicated		259		129					
Liquid fuel fired gas turbines	n.a.	water or steam injection	30 – 110	120 – 350							

Notes:

ESP	Electrostatic precipitator
FGD(w)	Wet flue-gas desulphurisation
SCR	Selective catalytic reduction of NO$_X$

Table 6.16: Emissions to air from liquid-fuel-fired combustion plants in normal operation at constant load

Substance	Coal	Heavy oil	Orimulsion
Dioxins and furans (pg/Nm^3)	2.193	2.492	2.159
PAH (µg/Nm^3)	0.0606	0.0507	0.0283

Table 6.17: Emission levels of dioxin and PAH from the combustion of different fuels [192, TWG, 2003]

6.3.3.2 Reduction of NO_X emissions from process heaters used in industrial applications

Control technique	Reduction rate (%)
Air-staged burner	25 – 35
Fuel-staged burner	40 – 50
Low excess air burner	20 – 25
Burner with external flue-gas recirculation	50 – 60
Burner with internal flue-gas recirculation	40 – 50
Air or fuel gas staging with internal flue-gas recirculation	55 – 75
Air or fuel gas staging with external flue-gas recirculation	60 – 80

Table 6.18: NO_X reduction of different low NO_X burner types [180, Baukal and Schwarz, 2001]

Control technique	Controlled emissions (mg/Nm^3)	Reduction rate (%)
Low NO_X burners	n.a.	25 – 65
Air-staged lances	n.a.	35 – 51
Fibre burner	20 – 40 (gas-fired)	
Ammonia injection	n.a.	43 – 70
Urea injection + low NO_X burners	n.a.	55 – 70
SCR	40 – 80	65 – 90
SCR + low NO_X burners	50 – 80	70 – 90

Table 6.19: NO_X control in process heaters [180, Baukal and Schwarz, 2001]

6.3.3.3 Emissions measured in liquid fuel-fired engine plants

Particulate (fuel: heavy fuel oil)	ISO 9096 standard or equivalent other method O_2 % reference point of 15 vol-% O_2
Heavy fuel oil: >1 wt-% S and <0.08 wt-% ash	Particulate <75 mg/Nm^3
Heavy fuel oil: <1 wt-% S and <0.06 wt-% ash, CCR <12 wt-%	Particulate <50 mg/Nm^3
Diesel oil (max. 0.02 wt-% ash)	Particulate <30 mg/Nm^3

Table 6.20: Particulate emissions of liquid fuel-fired engines [148, Euromot, 2002].

Type of engine	NO_X Emission (fuel: heavy fuel oil)	Remarks
Base engine optimised for low NO_X	NO_X <2300 mg/Nm^3	Standard diesel engine in production, until 2000
Liquid fuel-fired engines	NO_X 4800 mg/Nm^3	HFO (2.5 % S) SO_2, 3800 mg/Nm^3 5% O_2, no abatement
Base engine optimised for low NO_X (second generation)	NO_X <2000 mg/Nm^3	Standard diesel engine in production today
Injection retard	Typically up to 10 to 20 % NO_X reduction (depends on engine type)	Fuel consumption increase depends on the degree of injection retard, typically up to 3 %.
Addition of water	NO_X <1300 to 1600 mg/Nm^3	Used mostly in ships, fuel consumption increases
Note: reference point 15 vol-% O_2, dry gas, given at 0 degree C, 101.3 kPa. Steady state 85 to 100 % load of engine		

Table 6.21: Typical NO_X emissions achievable with engine modifications
[148, Euromot, 2002], [58, Eurelectric, 2001]

In the tables below (which use measurements from selected references), the following applies: emissions are in mg/Nm^3 (Nm^3 given at 0 °C, 101.3 kPa) at dry gas, 15 vol-% or 5 vol-% O_2. The SO_2 level depends on the fuel oil sulphur content, and particulate emissions mainly depend on the ash content of the fuel oil. The fuel is heavy fuel oil (HFO), unless otherwise stated. Steady state is a full engine load.

Installation	Fuel oil S wt-% or SO_2 (MCR = micro carbon residue)	NO_X (as NO_2)	Dust (ISO 9096, or equivalent other method), average	Remarks
Base low NO_X engine, optimised for NO_X	1.88 wt-% S, 0.05 wt-% ash, 13.8 wt-% MCR	2163 – 2178	56 – 60	70 MW$_e$ power plant in the Caribbean
Base low NO_X engine, optimised for NO_X	1.83 wt-% S, 0.06 wt-% ash, 13.6 wt-% MCR	1739 – 1881	54 – 61	100 MW$_e$ plant, in Central America
Note: Data refer in mg/Nm^3 – dry, 15 vol-% O_2, dry gas				

Table 6.22: NO_X optimised engine use
[148, Euromot, 2002]

Installation	Fuel oil S wt-% or SO_2	NO_X (as NO_2)	Dust (ISO 9096, or equivalent measurement method), average	Remarks
SCR	0.45 wt-% S	325 (dry, 15 vol-% O_2, dry gas)	44	30 MW$_e$ power plant in Asia
SCR	Diesel DIN 51603 and DIN 590	>90 % reduction to <90 mg/Nm^3 (at 5 % O_2)	n.a.	Diesel power plant in Germany with four SCR reactors, four urea dosing units with pumps, four control systems >70 % of CO to <20 mg/Nm^3 (at 5 % O_2)
SCR	gasoil	180 mg/Nm^3 (at 15 % O_2)	n.a.	31.6 MW$_e$ CHP power plant in the UK
SCR	HFO (2 – 3 % S)	153 mg/Nm^3 (at 15 % O_2)	n.a.	34 MW power plant
SCR	HFO (1 % S)	91 mg/Nm^3 (at 15 % O_2)	n.a.	3.8 MW marine propulsion
SCR	Diesel	150 mg/Nm^3 (at 15 % O_2)	n.a.	21 MW CHP power plant
SCR	Light fuel oil	145 mg/Nm^3 (at 15 % O_2)	n.a.	49 MW power plant

Table 6.23: Measured NO_X Emissions at diesel engine plants with SCR (mg/Nm^3)
[148, Euromot, 2002], [167, Rigby, et al., 2001], [181, Ceramics GmbH, 2002], [78, Finkeldei, 2000]

Installation	Fuel oil S wt-% or SO_2	NO_X (as NO_2)	Dust (ISO 9096, or equivalent measurement method), average	Remarks
Slow speed engine + 'water addition'	2 wt-% S HFO	1540	55	20 MW_e power plant in the Caribbean
Note: Units in mg/Nm^3 (dry, 15 vol-% O_2)				

Table 6.24: A primary method: water addition is used
[148, Euromot, 2002]

6.3.3.4 Emissions to water

Combustion Technique	Origin of waste water	Waste water treatment	Concentration in waste water (mg/l)						
			Hydrazine	Filterable matter	Sulphate	Sulphite	Fluoride	Hg	Sulphide
Heavy fuel oil boiler	Wet FGD	Fil/Pre/Floc/Sed/Neu		7.3	2130	20	3.3	0.002	
	Treatment of condensate and feed-water	Neu/Sed		17					0.8

Notes.
Fil = Filtration Pre = Precipitation Floc = Flocculation Sed = Sedimentation Neu = Neutralisation

Table 6.25: Emissions to water from oil-fired combustion plants in normal operation at constant load

Combustion Technique	Origin of waste water	Waste water treatment	Spec. waste water flowrate (m^3/MW_{th})	Concentration in waste water (mg/l)										
				Cl	AOX	COD	P	N	Zn	Cr	Cd	Cu	Pb	Ni+V
Heavy fuel oil boiler	Wet FGD	Fil/Pre/Floc/Sed/Neu	0.11	9.2		27.9		85	0.01	0.1	5	0.1	0.1	0.058
	Treatment of condensate and feed-water	Neu/Sed	0.056		1			840						
Combined cycle (light oil)	Treatment of condensate and feed-water	Neu/Sed	0.32		0.031	16.5	0.16	43.5	0.078	0.0038	0.0003	0.0044	0.0053	0/0036

Notes:
Fil = Filtration Pre = Precipitation Floc = Flocculation Sed = Sedimentation Neu = Neutralisation

Table 6.26: Emissions to water from oil-fired combustion plants in normal operation at constant load

6.3.3.5 Waste and residues

Beside the combustion and flue-gas treatment residues (ashes) and gypsum from the FGD unit, most of the other power plant's waste and residues will be the product of subsidiary activities, such as maintenance and the treatment of water. The waste substances associated with these subsidiary activities may include scrap metal, used oil, packaging materials, liquids used to wash down the compressors/gas turbines, ion exchanger and activated carbon. Ordinary domestic waste will also be produced.

Table 6.27 and Table 6.28 both provide average annual quantities of residues from oil-fired conventional power plants.

Residue	Avarage annual quatities (t/MW)
Lime residues from raw water decarbonisation	0
Loaded ion exchange resins	0.003
Screenings	0.033
Iron hydroxide slurry	0.937
Sedimentaion slurry	2.056

Table 6.27 Residues from raw water conditioning
[58, Eurelectric, 2001]

Residue	Avarage annual quatitie (t/MW)
Slurry from FGD waste water conditioning	0.371
Residues from process waste treatment	0.19
Neutralisation slurry	0.004
Residues from scrubbing and scouring waters	0.169
Residues from separators	0.293
Sediments	2.338

Table 6.28 Residues from waste water treatment Eurelectric
[58, Eurelectric, 2001]

Table 6.29 and Table 6.32 both provide examples of analysis of bottom ashes and fly ashes from liquid fired combustion plants.

Parameter	Unit	Plant A	Plant B
Cl	%		<0.01
F	%		<0.001
S	%		0.11
As	mg/kg	8.8	5
B	mg/kg		158.0
Ba	mg/kg		850
Be	mg/kg		1.0
Bi	mg/kg		3.3
Co	mg/kg		44.0
Cr	mg/kg	204.7	127.7
Cu	mg/kg	63.2	92.8
Li	mg/kg		81.0
Mn	mg/kg		582.5
Mo	mg/kg		3.8
Ni	mg/kg	214.9	94.0
Pb	mg/kg	9.9	9.0
Se	mg/kg	0.6	n.n*
Sn	mg/kg		22.7
V	mg/kg	96.6	204.2
Zn	mg/kg	38.9	89.0
TOC (als C)	% C		7.93
*n.n. Below detectable limits			

Table 6.29: Analysis of the bottom ash in two different plants
[192, TWG, 2003]

Parameter	Unit	Plant A	Plant B	Plant C	Plant D
Cl	%		<0.1	0.01	0.01
F	%			<0.001	0.005
S	%		<1	0.52	
PCDD/PCDF	ng TEQ/kg		<1		
Ag	mg/kg			0.3	
As	mg/kg	106.0	<50	32.5	75
B	mg/kg			231.0	
Ba	mg/kg			3170	
Be	mg/kg			8.0	
Cd	µg/kg	740	<500	n.n.	<1000
Co	mg/kg			81.5	1
Cr	mg/kg	194.9	<400	150.5	321
Cu	mg/kg	88.4	<100	155.5	767
Hg	µg/kg	860	<1000	<0.2	<1000
Li	mg/kg			131.0	
Mn	mg/kg			510.0	487
Mo	mg/kg			12.5	
Ni	mg/kg	90.0	<250	197.2	89
Pb	mg/kg	45.2	<100	81.2	45
Sb	mg/kg			n.n.	
Se	mg/kg	2.8		n.n.	
Sn	mg/kg			6.7	
TI	mg/kg		<2	n.n.	
TOC (as C)	% C		<8	1.75	
V	mg/kg	263.6		301.1	280
W	mg/kg			2.0	
Zn	mg/kg	236.1	<300	209.5	290
PCDD/PCDF	ng TE/kg		<1	209.5	290
*n.n. Below detectable limits					

Table 6.30: Analysis fo the fly ashes of three different plants
[192, TWG, 2003]

Table 6.33 shows the analysis of the filter cake produced in three different power plants.

Parameter	Unit	Plant A	Plant B	Plant C
Cl	mg/kg			1.3
F	mg/kg			0.26
TS 40 °C	%	44.3-58.6	57.1 - 66.7	
C	%	13.0-34.9	2.5 - 6.8	
Silicate	%	1.2-4.0	7.5 - 14.2	
Sulphate	%	24.2-43.1	10.0 - 35.7	
Carbonate	%	1.0-3.9	2.7 - 7.8	
Al	%	0.077-1.413	1.78 - 24.33	
As	mg/kg	1-16	16 - 46	41
Ba	%	0.005-0.010	0.029 - 0.093	
Ca	%	14.83-19.52	17.78 - 25.28	
Cd	µg/kg	n.n.	n.n.	4.000
Co	mg/kg	33-99	13 - 35	182
Cr	mg/kg	8-76	25 - 66	93
Cu	mg/kg	16-46	43 - 91	90
Fe	%	0.43-0.90	2.6 - 4.48	
Hg	µg/kg	n.n.*	n.n.*	76
K	%	0.020-0.094	0.31 - 0.64	
Na	%	0.025-0.115	0.14 - 0.32	
Mg	%	3.09-8.22	0.27 - 0.52	
Mn	%	0.014-0.033	0.04 - 0.12	2200
Mo	mg/kg	2-62	2 - 12	
Ni	%	0.170-0.491	0.002 - 0.006	11100 (mg/k)
Pb	mg/kg	21-47	25 - 66	103
Sb	mg/kg	10-21	1 - 12	
Sn	mg/kg	n.n.-4	2 - 10	
V	%	0.450-0.794	0.01 - 0.02	34000 (mg/kg)
Zn	mg/kg	19-425	82 - 342	758
*n.n. Below detectable limits				

Table 6.31: Analysis fo the filter cake of three plants
[192, TWG, 2003]

6.3.3.6 Residues from a waste water treatment plant

The following table shows as an example the elementary analysis of a press filter cake from a filter press in the waste water treatment plant operated in a power plant using HFO with an average supphur content of 1.89 %. The plant is equipped with an SCR, a wet ESP and a wet FGD unit.

	Test standard	Unit	*	Minimum	Maximum	Average
Dry Substance 105°C	OeN G 1.074	%		43.4	64.3	50.7
Carbon	OeN G 1.072	% C	<15	14.6	28.7	21.2
Silicate	gravimetric	% SiO_2	<40	2.1	4.1	3.0
Sulphate	DIN 38.405-D19	% SO_4	<65	21.6	51.2	37.7
Carbon dioxide	OeN G 1.072	% CO_2		0.6	10.6	3.7
Aluminium	DIN 38.406-E22	% Al	<10	0.188	0.390	0.298
Arsenic	DIN 38.406-E22	ppm As	<30	11	36	22
Barium	DIN 38.406-E22	% Ba	<0.2	0.007	0.016	0.010
Beryllium	DIN 38.406-E22	ppb Be	<10	n.d.	n.d.	n.d.
Calcium	DIN 38.406-E22	% Ca	<30	9.79	14.07	11.77
Cadmium	DIN 38.406-E22	ppb Cd	<10	n.d.	n.d.	n.d.
Cobalt	DIN 38.406-E22	ppm Co	<30	29	74	53
Chromium	DIN 38.406-E22	ppm Cr	<200	11	41	20
Copper	DIN 38.406-E22	ppm Cu	<100	12	46	27
Iron	DIN 38.406-E22	% Fe	<10	0.65	1.74	0.98
Mercury	OeN ISO 5.666	ppb Hg	<10	n.d.	n.d.	n.d.
Potassium	DIN 38.406-E22	% K	Σ <1	0.015	0.054	0.033
Sodium	DIN 38.406-E22	% Na		0.027	0.127	0.057
Magnesium	DIN 38.406-E22	% Mg	<10	5.15	8.53	6.35
Manganese	DIN 38.406-E22	% Mn	<,5	0.026	0.061	0.038
Molybdenum	DIN 38.406-E22	ppm Mo	<100	30	96	55
Nickel	DIN 38.406-E22	% Ni	<0.5	0.106	0.448	0.262
Lead	DIN 38.406-E22	ppm Pb	<500	23	109	54
Antimony	DIN 38.406-E22	ppm Sb	<30	2	37	20
Silver	DIN 38.406-E22	% Ag		n.d.	n.d.	n.d.
Tin	DIN 38.406-E22	ppm Sn	<500	n.d.	7	1
Thallium	DIN 38.406-E22	ppb Tl	<10	n.d.	n.d.	n.d.
Vanadium	DIN 38.406-E22	% V	<2	0.045	0.989	0.561
Zinc	DIN 38.406-E22	ppm Zn	<1.000	94	282	170
Note: * Operational Experience (guidance values) **Fuel: HFO (S 1.89 % average value)**						

Table 6.32: Example of the elementary analysis of a press filter cake from a filter press in the waste water treatment plant operated in a power plant using HFO
[192, TWG, 2003]

6.4 Techniques to consider in the determination of BAT for the combustion of liquid fuels

This section presents techniques that are considered in the determination of BAT for the prevention or reduction of emissions from the combustion of liquid fuels and measures to increase thermal efficiency. They are all currently commercially available. All the techniques considered have been described in a general way, but for most of the techniques, detailed descriptions are presented in Chapter 3 and for some techniques examples are given in Section 6.2. This is to demonstrate, in detail, the environmental performance of these techniques applied in real situations. In principle, techniques described in Chapter 3 apply, to a large extent, to the combustion of liquid fuels and should, in general, also be seen as techniques to consider in the determination of BAT. For more detailed descriptions, refer to Chapter 3.

To avoid duplication throughout this document, refer to Environmental Management Systems (EMS) in Section 3.15.

6.4.1 Techniques for the unloading, storage and handling of liquid fuel and additives

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Tanks grouped inside a retention basin	Reduced risk of water and soil contamination	Possible	Possible	High	None	Not available	The retention basin, should be designed to hold all or part of the volume (75 % of maximum capacity of all tanks but at the least the maximum volume of the largest tank)
Automatic control systems to prevent overfilling of storage tanks.	Reduced risk of water and soil contamination	Possible	Possible	High	None	Not available	
Double walled type of pipes with automatic control of the spacing for underground pipes	Reduced risk of water and soil contamination	Possible	Possible	High	None	Not available	
Regular checks of the storage facilities and piping	Reduced risk of water and soil contamination	Possible	Possible	High	None	Not available	
Enclosed storage of lime/limestone in silos with dust abatement	Reduction of fine particle emissions	Possible	Possible	High	None	Not available	
Sealed surfaces with drainage systems (including oil traps)	Prevention of soil and groundwater contamination	Possible	Possible	High	None	Cost for waste water treatment	The collected drainage water needs to be treated to avoid water contamination by fuel or lubrication oil
Storage of ammonia as ammonia-water solution	Higher safety	Possible	Possible	High	Less storage risks than if just storing as pressurised liquid ammonia	Not available	

Table 6.33: Techniques for the unloading, storage and handling of liquid fuel and additives

6.4.2 Techniques to increase the efficiency of liquid-fuel-fired boilers

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Combustion cycle							
Co-generation of heat and power (CHP)	Increased efficiency	Possible	Very limited	High			
Change of turbine blades	Increased efficiency	Possible	Possible	High	None	Not available	Steam turbine blades can be changed to three-dimensional blades during regular maintenance intervals
Use of advanced materials to reach high steam parameters	Increased efficiency	Possible	Not possible	Practised in new plants	None	Not available	The use of advanced materials allows steam pressures of 300 bar and steam temperatures of 600 °C
Supercritical steam parameters	Increased efficiency	Possible	Not possible	Practised in new plants	None	Not available	
Double reheat	Increased efficiency	Possible	Very limited	Practised mainly in new plants	None	Not available	
Regenerative feed-water heating	Increased efficiency	Possible	Sometimes possible	Practised in new plants and some existing ones	None	Not available	New plants use up to 10 stages resulting in a feed-water temperature of about 300 °C
Advanced computerised control of combustion conditions for emission reduction and boiler performance	Increased boiler efficiency	Possible	Possible	High	None	Plant specific	
Energetic optimisation of plant equipment							
Low excess air	Increased efficiency and reduced NO_X and N_2O emissions	Possible	Possible	High	None	Not available	
Lowering of exhaust gas temperatures	Increased efficiency	Possible	Possible	High		Not available	
Low CO concentration in flue-gas	Increased efficiency	Possible	Possible	High	Low NO_X emissions leads to higher CO levels	Not available	The emissions of NO_X and CO need to be optimised
Heat accumulation (Heat storage)		Possible	Possible			Not available	Increases the energy generated with CHP mode

Table 6.34: Techniques to increase the efficiency of liquid-fuel-fired boilers

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Flue-gas cleaning and discharge							
Cooling tower discharge	Reheating of flue-gas after the FGD plant is not necessary	Possible	Possible	High	No stack is needed	No additional cost for constructing and maintenance of a stack	
Cooling system							
Different techniques							See cooling BREF

Table 6.35: Techniques to increase the efficiency of liquid-fuel-fired boilers (continuation of Table 6.28)

6.4.3 Techniques for the prevention and control of dust and heavy metal emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Low ash/sulphur liquid fuel or natural gas	Reduction of particulate and SO_2 emissions	Possible	Possible	High	None		
ESP	Reduction of particulate matter and heavy metals	Possible	Possible	High	None		ESP widely used for boilers. Secondary particulate reduction methods are new for diesel engines, the first commercial ESP is under installation
Fabric Filter	Reduction of particulate emissions particularly fine dust ($PM_{2.5}$ and PM_{10}) and heavy metals	Possible	Possible	High	None		The FF is less important than the ESP, because of the elevated risk of fire, which can be reduced if the FF is applied in combination with FGD
Particle filter for liquid fuel fired engines	Reduction of particulate emissions particularly of soot particles	Possible		Limited			Secondary cleaning devices for particulates is currently under development for larger diesel engines
Combustion additives	Reduction of dust at the source	Possible	Possible	High		1 to 3 % of the fuel price	
Low asphaltene fuel oil	Reduction of dust emissions at the source	Possible	Possible			less than 10 % of the fuel price/	If available, depends on the refining process.

Table 6.36: Techniques for the prevention and control of dust and heavy metal emissions

6.4.4 Techniques for the prevention and control of SO_2 emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Use of low sulphur fuel oil	Reduction of SO_2 emissions at the source	Possible	Possible	High		Depends on the type and quality of fuel oil	
Oil and gas co-combustion	Reduction of SO_2 reduction at the source	Possible	Possible	High	Decreased simultaneouly NO_X and CO_2 emissions	Depends on fuel price differences	Could help for energy consumption optimisation
Fluidised bed combustion (FBC)	Reduction of SO_2 reduction inside the boiler	Possible	Not possible	Good	Decreased simultaneouly NOx emissions		Valid for co-combustion with solid fuel

Table 6.37: Techniques (primary measures) for the prevention and control of SO_2 emissions

	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Wet lime/limestone scrubber with gypsum production	Reduction of SO_2, dust emissions	Possible but rarely applied in plants below 100 MW_{th}	Possible	High	Because of the used source of lime, the emissions of As, Cd, Pb and Zn might be slightly higher. Water emissions. Plume formation at the stack outlet if wastes gases are not reheated.	Plant specific	Because of the high costs of the wet scrubbing process, this technique is the more economic solution for larger sized plants only. The existing wet scrubber can be improved by optimising the flow pattern in the absorber
Seawater scrubber	Reduction of SO_2,dust emissions	Possible	Possible	High	Tendency to lead to reduced pH-levels in the vicinity of the water discharge, and the emission of heavy metals and remaining ash to the marine environment	Plant specific	The use of a seawater scrubber strongly depends on the specific situation because of the pollution impact to the marine environment
Other wet scrubber types	Reduction of SO_2	Possible, but rarely applied for new plants	Depends on the individual plant	Very limited	Depends on the technique	Not available	The reduction of other pollutants depends on the specific technique
Spray dry scrubber	Reduction of SO_2 emissions	Possible	Possible	High	Residues that need to be landfilled	Plant specific	Spray dry scrubbers first produce dust, they reduce dust emissions only in combination with effective particulate removal systems (FF, ESP)
Others	Reduction of SO_2, and in the combined technique also a reduction of NO_X	Possible, but rarely applied for new plants	Depends on the individual plant	Very limited		Not available	The reduction of other pollutant depends on the specific technique

Table 6.38: Techniques (secondary measures) for the prevention and control of SO_2 emissions

6.4.5 Techniques for the prevention and control of NO_X and N_2O emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Primary measures for boilers and process heater							
Low excess air	Reduction of NO_X, CO, HC and N_2O emissions, increased efficiency	Possible	Possible	High		Plant specific	Only for boilers and process heaters
Air-staging (OFA)		Possible	Possible	High		Plant specific	Only for boilers and process heaters
Flue-gas recirculation		Possible	Possible	High		Plant specific	Only for boilers and process heaters
Low NO_X burners (advances second or third generation of low NO_X burners)	Reduction of NO_X	Possible	Possible	High	Tendency to imcomplete combustion		Only for boilers and process heaters Older plants may have problems according to the flame length of modern low NO_X burners
Reburning	Reduction of NO_X	Possible	Possible	High		Plant specific	Only for boilers
Primary measures for engines and gas turbines							
Engine modifications (Section 6.1.10.3.3)	Reduction of NO_X	Possible	Not possible	High		Plant specific	Only for engines
Direct steam injection	Reduction of NO_X	Possible	Possible	High	Increased fuel consumption		For diesel engines and gas turbines only
Direct water injection	Reduction of NO_X	Possible	Possible	Limited	Increased fuel consumption		For diesel engines and gas turbines only
Injection of water/fuel emulsion or humid air	Reduction of NO_X	Possible	Possible	Limited			For diesel engines and gas turbines only
Secondary measures							
Selective Non Catalytic Reduction (SNCR)	Reduction of NO_X, but the reduction rate is much less than with SCR	Possible	Possible	High	Ammonia slip and ammonia sulphate salts formation	Plant specific	Only for boilers and process heaters
Selective Catalytic Reduction (SCR)	Reduction of NO_X	Possible	Possible	High	Ammonia slip	Plant specific	For boilers, process heaters and diesel, as well as HFO fired engines
Combined techniques	Reduction of NO_X and SO_2	Possible	Limited	Limited		Not available	The combined techniques has only a small market share compared to SCR techniques

Table 6.39: Techniques for the prevention and control of NO_X and N_2O emissions

6.4.6 Techniques for the prevention and control of water pollution

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Wet FGD							
Water treatment by flocculation or sedimentation	Removal of fluoride, heavy metal, COD and particulates	Possible	Possible	High	Sludge can be added to coal internally and in the FGD, or as a filling material in the mining industry	Plant specific	
Ammonia reduction by air stripping, precipitation or biodegradation	Reduced ammonia content	Only applicable if ammonia content in waste water is high because of the SCR/SNCR used upstream of the FGD		High		Plant specific	
Closed loop operation	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Regeneration of demineralisers and condensate polishers							
Neutralisation and sedimentation	Reduced waste water discharge	Possible	Possible	High	Sludge that needs to dewatered to be disposed of	Plant specific	
Elutriation							
Neutralisation		Only with alkaline operation		High		Plant specific	
Washing of boilers, air preheaters and precipitators							
Neutralisation and closed loop operation, or replacement by dry cleaning methods	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Surface run-off							
Sedimentations or chemical treatment and internal re-use	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Use of oil trap systems	Less risk of water and soil contamination	Possible	Possible	High			

Table 6.40: Techniques for the prevention and control of water pollution

6.5 Best available techniques (BAT) for the combustion of liquid fuels

In understanding this section and its contents, the attention of the reader is drawn back to the preface of this document and in particular the fifth section of the preface: ‘How to understand and use this document’. The techniques and associated emission and/or consumption levels, or ranges of levels, presented in this section have been assessed through an iterative process involving the following steps:

- identification of the key environmental issues for the sector; which are emissions to air and water, thermal efficiency and combustion residues
- examination of the techniques most relevant to address those key issues
- identification of the best environmental performance levels, on the basis of the available data in the European Union and worldwide
- examination of the conditions under which these performance levels were achieved; such as costs, cross-media effects, main driving forces involved in the implementation of this techniques
- selection of the best available techniques (BAT) and the associated emission and/or consumption levels for this sector in a general sense all according to Article 2(11) and Annex IV of the Directive.

Expert judgement by the European IPPC Bureau and the relevant Technical Working Group (TWG) has played a key role in each of these steps and in the way in which the information is presented here.

On the basis of this assessment, techniques, and as far as possible emission and consumption levels associated with the use of BAT, are presented in this section that are considered to be appropriate to the sector as a whole and in many cases reflect current performance of some installations within the sector. Where emission or consumption levels ‘associated with best available techniques’ are presented, this is to be understood as meaning that those levels represent the environmental performance that could be anticipated as a result of the application, in this sector, of the techniques described, bearing in mind the balance of costs and advantages inherent within the definition of BAT. However, they are neither emission nor consumption limit values and should not be understood as such. In some cases, it may be technically possible to achieve better emission or consumption levels but due to the costs involved or cross-media considerations, they are not considered to be appropriate as BAT for the sector as a whole. However, such levels may be considered to be justified in more specific cases where there are special driving forces.

The emission and consumption levels associated with the use of BAT have to be seen together with any specified reference conditions (e.g. averaging periods).

The concept of ‘levels associated with BAT’ described above is to be distinguished from the term ‘achievable level’ used elsewhere in this document. Where a level is described as ‘achievable’ using a particular technique or combination of techniques, this should be understood to mean that the level may be expected to be achieved over a substantial period of time in a well maintained and operated installation or process using those techniques.

Where available, data concerning costs have been given together with the description of the techniques presented in the previous sections. These give a rough indication about the magnitude of costs involved. However, the actual cost of applying a technique will depend strongly on the specific situation regarding, for example, taxes, fees, and the technical characteristics of the installation concerned. It is not possible to evaluate such site-specific factors fully in this document. In the absence of data concerning costs, conclusions on economic viability of techniques are drawn from observations on existing installations.

It is intended that the general BAT in this section are a reference point against which to judge the current performance of an existing installation or to judge a proposal for a new installation. In this way they will assist in the determination of appropriate 'BAT-based' conditions for the installation or in the establishment of general binding rules under Article 9(8). It is foreseen that new installations can be designed to perform at, or even better than, the general BAT levels presented here. It is also considered that existing installations could move towards the general BAT levels or do better, subject to the technical and economic applicability of the techniques in each case.

While the BREFs do not set legally binding standards, they are meant to give information for the guidance of industry, Member States and the public on achievable emission and consumption levels when using specified techniques. The appropriate limit values for any specific case will need to be determined taking into account the objectives of the IPPC Directive and the local considerations.

To avoid duplication throughout this document, refer to BAT on Environmental Management System (EMS) in Section 3.15.1.

6.5.1 Unloading, storage and handling of liquid fuel and additives

BAT in preventing releases from unloading, storage and handling of liquid fuels, but also for additives such as lime, limestone, ammonia, etc. are summarised in Table 6.41.

Material	Pollutant	BAT (not exhaustive list)
Liquid fuel	Water contamination	• the use of liquid fuel storage systems that are contained in impervious bunds that have a capacity capable of containing 50 - 75 % of the maximum capacity of all tanks or at least the maximum volume of the biggest tank. Storage areas should be designed so that leaks from the upper portions of tanks and from delivery systems are intercepted and contained in the bund. Tank contents should be displayed and associated alarms used. The use of planned deliveries and automatic control systems can be applied to prevent the overfilling of storage tanks • pipelines placed in safe, open areas aboveground so that leaks can be detected quickly and damage from vehicles and other equipment can be prevented. If buried pipelines are used their course can be documented and marked and safe excavation systems adopted. For underground pipes, double walled type pipes with automatic control of the spacing and special construction of piping (steel pipes, welded connections and no valves in underground section etc.) are BAT • surface run-off (rainwater) that might be contaminated by any spillage of fuel from the storage and handling should be collected and treated before discharge.
Lime and Limestone		• enclosed conveyors, pneumatic transfer systems and silos with well designed, robust extraction and filtration equipment on delivery and conveyor transfer points to prevent the emission of dust.
Pure liquified ammonia	Health and safety risk according to ammonia	• for handling and storage of pure liquified ammonia: pressure reservoirs for pure liquified ammonia >100 m^3 should be constructed as double wall and should be located subterraneously; reservoirs of 100 m^3 and smaller should be manufactured including annealling process • from a safety point of view, the use of an ammonia water solution is less risky than the storage and handling of pure liquefied ammonia.

Table 6.41: BAT for the unloading, storage and handling of liquid fuel and additives

6.5.2 Pretreatment of liquid fuels used in engines and gas turbines

For diesel oil used as a fuel in gas turbines and engines, fuel pretreatment plants, which comprise diesel oil cleaning units of the centrifuge self-cleaning type or of the electrostatic type, are considered as BAT. With heavy fuel oil (HFO) firing, the fuel treatment plant comprises heaters for heating the HFO (electrical or steam coil type); de-emulsifier dosing systems, for breaking up the oil emulsion; separators (centrifugal or electrostatic type), for removing the solid impurities; and additive dosing systems, for raising the melting point of the vanadium oxidation products. Reference is given to the measures described in Sections 6.1.2.2 and 6.1.2.3 of this document.

6.5.3 BAT for liquid fuel-fired boilers

6.5.3.1 Thermal efficiency

For the reduction of greenhouse gases, in particular the releases of CO_2 from liquid fuel-fired combustion plants, the best available options, from today's point of view, are techniques and operational measures to increase thermal efficiency. This goes along with the application of advanced computerised control systems for controlling the combustion conditions to maximise the emission reduction and boiler performance. Secondary measures of CO_2 capture and disposal, as described in Annex 10.2 of this document, are at a very early stage of development. These techniques might be available in the future, but they cannot yet be considered as BAT.

For condensing power plants, energy efficiency has been related to, and considered as, the heat rate (fuel input energy/energy output at power plant border) and as the power plant efficiency, which is to be understood here as the inverse of the heat rate, i.e. the percentage of produced energy/fuel input energy. The fuel energy is measured as the lower heating value. By applying the measures listed in Section 6.4.2 to improve the thermal efficiency, such as double reheat and the use of the most advanced high temperature materials, liquid fuel-fired condensing power plants can achieve comparable efficiencies to hard coal-fired plants.

The co-generation of heat and power (CHP) is one of the technically and economically most efficient means of increasing the energy efficiency of an energy supply system. Co-generation is, therefore, considered as the most important BAT option in order to reduce the amount of CO_2 released to the atmosphere per unit of energy generated. CHP should be an aim for any new build power plant whenever economically feasible, i.e. whenever the local heat demand is high enough to warrant the construction of the more expensive co-generation plant instead of the simpler heat or electricity only plant. Because the demand for heat varies throughout the year, CHP plants need to be very flexible concerning the ratio of produced heat to electricity. They should also possess high efficiencies for part load operation.

The exergetic efficiency (see also Section 2.7.5) associated with the operation of a CHP plant under BAT conditions, is considered to be 45 – 55 %, which is equal to a heat rate in the range of 1.3 – 1.1 and an energy (fuel) efficiency of 75 – 90 %, depending on the plant specific application.

It should be borne in mind that these BAT levels are not attainable under all operational conditions. Energy efficiency is greatest at the design point of the plant. The actual energy efficiencies throughout the operational period of the plants may be lower due to changes in the load during the operation, quality of the fuel, etc. The energy efficiency also depends on the cooling system of the power plant, its geographical location (see Table 2.3), and on the energy consumption of the flue-gas cleaning system.

For existing liquid fuel-fired plants, a number of retrofit and repowering techniques can be applied to improve the thermal efficiency. The technical measures described in Section 2.7.9 should be taken into account as part of the BAT options to improve the efficiency of existing plants. The use of advanced computerised control systems in order to achieve a high boiler performance with increased combustion conditions that support the reduction of emissions are also considered as BAT.

In general, the following measures need to be taken into consideration to increase efficiency:

- combustion: minimising the heat loss due to unburned gases and elements in solid wastes and residues from combustion
- the highest possible pressure and temperature of the working medium steam. Repeated superheating of the steam to increase net electric efficiency
- the highest possible pressure drop in the low pressure end of the steam turbine through the lowest possible temperature of the cooling water (fresh water cooling)
- minimising the heat loss through the flue-gas (utilisation of residual heat or district heating)
- minimising the heat loss through conduction and radiation with isolation
- minimising the internal energy consumption by taking appropriate measures, e.g. scorification of the evaporator, greater efficiency of the feed water pump etc.)
- preheating the boiler feed water with steam
- improving blade geometry of the turbines.

6.5.3.2 Dust and heavy metals emissions

For dedusting off-gases from new and existing liquid fuel-fired combustion plants, BAT is considered to be the use of an electrostatic precipitator (ESP) or a fabric filter. Cyclones and mechanical collectors alone are not BAT, but they can be used as a pre-cleaning stage in the flue-gas path.

Liquid fuels, especially HFO, typically contain heavy metals, in particular Vanadium and nickel. Basically, most of the heavy metals evaporate in the combustion process and condense later in the process on the surfaces of the particulate matter (e.g. fly ash). The ESP is the most used technique for dedusting flue-gases from HFO firing. The FF is also an applied technique but less important because of the elevated risk of fire, which is reduced if the FF is applied in combination with FGD. Therefore, BAT to reduce the emissions of dust and heavy metals are the use of high performance ESPs (reduction rate of >99.5 %) or, taking into account the point mentioned above, a fabric filter (reduction rate of >99.95 %).

Periodic monitoring for heavy metals is BAT. A frequency of every year up to every third year, depending on the kind of liquid fuel used is recommended. Total-Hg especially needs to be monitored and not only the part bound to particles.

The associated dust levels take into account the need to reduce fine particulates (PM_{10} and $PM_{2.5}$) and to minimise the emission of heavy metals, since they have the tendency to accumulate preferentially on the finer dust particulates. For combustion plants over 300 MW_{th}, the dust levels are lower because the wet scrubber (FGD) that is part of the BAT conclusion for desulphurisation also reduces particulate matter.

The BAT conclusion for dedusting and the associated emission levels are summarised in Table 6.42. The BAT associated emission levels are based on a daily average, standard conditions and an O_2 level of 3 %, and represents a typical load situation. For peak load, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher, have to be regarded.

Capacity (MW$_{th}$)	Dust emission level (mg/Nm^3)		BAT to reach these levels	Monitoring	Applicability
	New plants	Existing plants			
50 – 100	5 – 20(1)	5 – 30(2)	ESP/FF	Continuous (1,2)	New and existing plants
100 – 300	5 – 20(3)	5 – 25(4)	ESP/FF/in combination FGD (wet) (depending on the specific plant size)	Continuous	New and existing plants
>300	5 – 10(5)	5 – 20(6)	ESP/FF/in combination with FGD (wet)	Continuous	New and existing plants

Notes:
ESP (Electrostatic precipitator) **FF** (Fabric filter) **FGD(wet)** (Wet flue-gas desulphurisation)

	Industry and one Member State declared that emission levels have to be presented for cases where dust emissions are controlled by ESPs only without the application of a wet FGD. The following levels were proposed:
1, 2	10 – 50 mg/Nm^3 for ESP, monitoring periodically
3, 5	upper level 30 mg/Nm^3 for ESP
4, 6	upper level 50 mg/Nm^3 for ESP
1 – 6	50 – 100 mg/Nm^3 for burners with steam atomisation or use of additives regardless of the existing power plant's capacity.
3 – 6	Industry claimed an upper level of 15 mg/Nm^{3}for ESP or FF in combination with a wet FGD
4, 6	One Member State proposed that the BAT range for existing plants with a capacity over 100 MW$_{th}$ should be 10 – 50 mg/Nm^3, because these levels comply with the Member States emission limits.
2	One Industry representative mentioned that dust emissions of around 50 mg/Nm^3 are achieved. To reduce this to 30 mg/Nm^3 by fitting fabric filters or ESPs to achieve a corresponding reduction of around 20 tonnes of dust per year cannot represent BAT.

Table 6.42: BAT for dedusting off-gases from liquid fuel fired combustion plants

6.5.3.3 SO$_2$ emissions

In general, for liquid fuel-fired combustion plants, the use of low sulphur fuel oil and/or desulphurisation are considered to be BAT. However, the use of low sulphur fuel oil for plants over 100 MW$_{th}$ can, in most cases, only be seen as a supplementary but generally not in itself sufficient way to reduce SO$_2$. In sites where natural gas is available, co-combustion of gas and oil is also part of BAT.

Besides the use of low sulphur fuel oil, the techniques that are considered to be BAT are mainly the wet scrubber (reduction rate 92 - 98 %), and the spray dry scrubber desulphurisation (reduction rate 85 – 92 %), which already has a market share of more than 90 % of flue-gas desulphurisation techniques. Dry FGD techniques, such as dry sorbent injection, are used mainly for plants with a thermal capacity of less than 300 MW$_{th}$. The wet scrubber has also the advantage of reducing emissions of HCl, HF, dust and heavy metals. Existing plants that have already applied a wet FGD system can reduce the SO$_2$ emissions further by optimising the flow pattern in the absorber vessel. The wet scrubbing process is an expensive option for smaller plants and has, therefore, not been considered as BAT for plants with a capacity of less than 100 MW$_{th}$.

The seawater scrubber has been considered to be part of the BAT conclusion because of its high reliability, and because it is a simple process which does not require slurry handling and does not generate by-products. The local conditions, such as seawater conditions, tidal flows, the marine (aquatic) environment close to the scrubber water outlet, etc. need to be carefully examined in order to avoid any negative environmental and ecological effects. Effects may arise from the reduction of the pH level in the general vicinity of the power plant as well as from the input of any remaining metals (heavy metals) and fly ash.

The BAT conclusion for desulphurisation and the associated emission levels are summarised in Table 6.43. The BAT associated emission levels are based on a daily average, standard conditions and an O_2 level of 3 %, and represents a typical load situation. For peak load, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher, have to be regarded.

Capacity (MW_{th})	**SO_2 emission level associated with BAT (mg/Nm^3)**		**BAT options to reach these levels**	**Applicability**	**Monitoring**
	New plants	Existing plants			
50 – 100	100 – 350(1)	100 – 350(2)	Low sulphur fuel oil co-combustion of gas and oil FGD (dsi) or FGD (sds)	New and existing plants	Continuous
100 – 300	100 – 200(3)	100 – 250(4)	Low sulphur fuel oil co-combustion of gas and oil and FGD (dsi) or FGD (sds) or FGD (wet) (depending on the plant size) Seawater scrubbing Combined techniques for the reduction of NO_x and SO_2	New and existing plants	Continuous
>300	50 – 150(5)	50 – 200(6)	Low sulphur fuel oil co-combustion of gas and oil and FGD (wet) FGD (sds) Seawater scrubbing Combined techniques for the reduction of NO_x and SO_2	New and existing plants	Continuous

Notes:
FGD(w et) (Wet flue-gas desulphurisation) **FGD(sds)** (Flue-gas desulphurisation by using a spray drier)
FGD(dsi) (Flue-gas desulphurisation by dry sorbent injection)

	The following levels were proposed by Industry and the one Member State:
1,2	range to be 200 – 850 mg/Nm^3
3, 4, 6	upper level 400 mg/Nm^3
5	upper level 200 mg/Nm^3
2, 4, 6	Industry declared no BAT level should be given if low sulphur fuel is used. Their rationale is that for oil-fired LCPs, the SO_2 emission levels by using low sulphur fuel in combination with FGD are designed to optimise environmental benefit with the high cost of fuel and the FGD. The high net unit efficiency requirement has to be optimised among the cost of the fuel, the emission control technique performance (low emission levels) and the related energy consumption (energy penalty). The Member State argued that heavy fuel oil burners operate with a very high cost fuel. The SO_2 reduction techniques and the associated emission levels have to be reasonable, in order to ensure the economic viability of the plants, with very careful assessment of the environmental benefit against all the costs and the cross-media effects involved. It is very important for existing plants to allow the use of low sulphur fuel only in order to avoid any drop in net unit efficiency.
6	One Member State proposed that the BAT range for exisiting plants over 300 MW should be 200 – 400 mg/Nm^3, because these levels comply with the Member States emission limits.

Table 6.43: BAT for the prevention and control of sulphur dioxide from liquid fuel-fired combustion plants

6.5.3.4 NO_X emissions

In general, for liquid fuel-fired combustion plants, the reduction of nitrogen oxides (NO_X) by using a combination of primary and/or secondary measures such as SCR is considered to be BAT. The nitrogen compounds of interest are nitric oxide (NO), nitrogen dioxide (NO_2), collectively referred to as NO_X and nitrous oxide (N_2O).

For combustion plants over 50 MW_{th} and in particular for large plants over 100 MW_{th} for the reduction of NO_X emissions, BAT is considered to be the use of primary measures in combination with SCR or other end-of-pipe techniques. For small plants below 50 MW_{th}, it is not generally necessary to apply SCR, but it is an applied technique that can be used.

The economic feasibility of applying an SCR system to an existing boiler is primarily a question of the expected remaining lifetime of the plant, which cannot necessarily be decided solely by the age of the plant. The use of SCR has the disadvantage of a slide ammonia emission (ammonia slip). For the ammonia concentration, a level of less than 5 mg/Nm^3 is considered as BAT and is associated with the use of SCR. Combined techniques for the reduction of NO_X and SO_2 are described in Section 3.5 as part of the BAT conclusion, but their advantages, disadvantages and applicability need to be verified at a local level.

For combustion plants with a capacity of less than 100 MW_{th}, the use of a combination of different low NO_X primary measures is considered to be BAT.

The furnace height in old plants is usually small and may prevent the installation of overfire air ports. Even if there is room for an OFA, then the residence time of the combustion gases in the upper part of the furnace may not be long enough for complete combustion. In boilers that were built in years in which more was known about NO_X formation, the furnace will be larger and lower NO_X levels can be achieved. The best results will be obtained when low NO_X combustion is integrated into the boiler design, i.e. in new installations.

The BAT conclusion for the prevention and control of NO_X emissions and the associated emission levels are summarised in Table 6.44. The BAT associated emission levels are based on a daily average, with standard conditions and an O_2 level of 3 %, and represents a typical load situation. For peak load, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher, have to be regarded.

	NO_x emission level associated with BAT (mg/Nm^3)		BAT options to achieve these levels	Applicability	Monitoring
	new plants	Existing plants			
50 - 100	150 – 300[(1)]	150 – 450	Combination of Pm (such as air and fuel staging, low-NO_x burner, etc. For LFO firing NO_X <300 mg/Nm^3 For HFO firing with max 0,2 % N in fuel oil NO_X <360 mg/Nm^3 fFr HFO firing with max 0,3 % N in fuel oil NO_X <450 mg/Nm^3 SCR SNCR in case of HFO firing	New and existing plants	Continuous (6)
100 - 300	50 – 150[(2)]	50 – 200[(3)]	Combination of Pm (such as air and fuel staging, low-NO_x burner, reburning, etc) in combination with SNCR, SCR or combined techniques	New and existing plants	Continuous
>300	50 – 100[(4)]	50 – 150[(5)]	Combination of Pm (such as air and fuel staging, low-NO_x burner, reburning, etc) in combination with SCR or Combined techniques	New and existing plants	Continuous
	Industry and one Member State proposed the following levels				
1, 5	upper level 400 mg/Nm^3				
2, 4	upper level 200 mg/Nm^3				
3	upper level 450 mg/Nm^3				
6	Industry claimed that they wanted to change 'continuous' by 'periodical' monitoring The rationale given for existing plants is that the new values proposed allow power plants to use heavy fuel oil with high N content with NO_x abatement primary measures only				
5	One Member State proposed that the BAT range for existing plants over 300 MW should be 100 – 400 mg/Nm^3, because these levels comply with the Member States emission limits				
1	A TWG member proposed to reduce the lower end of the range to 100 mg/Nm^3, because this reflected the performance of SCRs				

Table 6.44: BAT for nitrogen oxide prevention and control in liquid fuel-fired combustion plants

6.5.3.5 Carbon monoxide (CO)

BAT for the minimisation of CO emissions is complete combustion, which goes together with good furnace design, the use of high performance monitoring and process control techniques and maintenance of the combustion system. Besides the combustion conditions, a well optimised system to reduce emissions of NO_X will also keep the CO levels between 30 and 50 mg/Nm^3.

6.5.3.6 Ammonia (NH_3)

The disadvantage of SNCR and SCR systems is the emission of unreacted ammonia into the air (ammonia slip). The ammonium concentration in the emission associated with the use of BAT is considered to be below 5 mg/Nm^3. The ammonium slip is often the limiting factor in the utilisation of an SNCR technique. To avoid the ammonia slip with the SNCR technique. A layer of SCR catalyst may be installed in the economiser area of the boiler, if the flue-gas temperature level is adequate to. As this catalyst reduces ammonia slip, it also reduces the corresponding amount of NO_X.

6.5.3.7 Water pollution

Different waste water streams (see Chapter 1) are generated by liquid fuel-fired combustion plants. To reduce emissions to water and to avoid water contamination, all measures that have been presented in Section 6.4.6 are considered to be BAT.

The danger of oil contamination is of an entirely different scale, when considering the risk of accidents in oil transportation or storage at oil-fired power plants. These problems are, however, no different from the normal risks associated with oil transport and storage in general; so there are no LCP specific issues to deal with in this respect.

Small amounts of oil contaminated (washing) water cannot be prevented from occurring occasionally at a power plant. Oil separation wells are, in general, sufficient to avoid any environmental damage.

The BAT conclusion for wet scrubbing desulphurisation is related to the application of a waste water treatment plant. The waste water treatment plant consists of different chemical treatments to remove heavy metals and to decrease the amount of solid matter from the water. The treatment plant includes the adjustment of pH, the precipitation of heavy metals and removal of the solid matter and the precipitate from the waste water. With modern technology, the following parameters are monitored: pH, conductivity, temperature, solid content, chlorine content, heavy metal concentrations (such as Cd, Hg, As, Cr, Cu, Ni, Zn, V, Pb), fluorine concentration and chemical oxygen demand (COD). The quality of the waste water after the waste water treatment plant varies a lot according to the fuel quality, desulphurisation process and to the discharge of the waste water. Nevertheless, emissions levels associated with the use of a BAT waste water treatment plant are summarised in Table 6.45.

Emission to water from Wet FGD waste water treatment plant (mg/l)	
COD	<150
F	1 – 30
Nitrogen compounds	<50
Solids	5 – 30
Sulphate	1000 – 2000
Sulphide	<0.2
Sulphite	0.5 – 20
Cd	<0.05
Cr	<0.5
Cu	<0.5
Hg	0.01 – 0.02
Ni	<0.5
Pb	<0.1
Zn	<1

Table 6.45: Emissions levels associated with the use of a BAT – FGD waste water treatment plant given as a representative 24 hour composite sample

The BAT measures to avoid or to reduce emissions to water are summarised in the following Table 6.46.

Technique	Main environmental benefit	Applicability	
		New plants	Retrofitted plants
For plants with wet FGD			
Water treatment by flocculation, sedimentation, filtration, ion-exchange and neutralisation	Removal of fluoride, heavy metals, COD and particulates	BAT	BAT
Ammonia reduction by air stripping, precipitation or biodegradation	Reduced ammonia content	BAT only if ammonia content in waste water is high because of SCR/SNCR used upstream FGD	
Closed loop operation	Reduced waste water discharge	BAT	BAT
Regeneration of demineralisers and condensate polishers			
Neutralisation and sedimentation	Reduced waste water discharge	BAT	BAT
Elutriation			
Neutralisation		BAT only in the case of alkaline operation	
Washing of boilers, air preheaters and precipitators			
Neutralisation and closed loop operation, or replacement by dry cleaning methods	Reduced waste water discharge	BAT	BAT
Surface run-off			
Sedimentations or chemical treatment and internal re-use	Reduced waste water discharge	BAT	BAT

Table 6.46: BAT for waste water treatment

The other techniques described for waste water treatment in Chapter 3 can also, in general, be considered as BAT for this sector.

6.5.3.8 Combustion residues

A lot of attention has already been paid by industry to the utilisation of combustion residues and by-products instead of depositing them in landfills. Utilisation and re-use is, therefore, the best available option.

There are many different targets of utilisation for different by-products. Each different means of utilisation sets specific criteria for the quality of ash, etc. It is impossible to cover all of these criteria in this BAT reference document, however the quality criteria are usually connected to the structural properties of the residue and related to the content and properties of any harmful substances in the residue, such as ash, solubility of heavy metals, etc.

The ash resulting from fuel-oil combustion presents, in particular when HFO is fired, a high content of unburned carbon. This ash can, therefore, be incinerated (in industrial kilns) or can be re-injected into the combustion chamber of a boiler with FGD and SCR systems.

The end-product of the wet scrubbing technique is gypsum, which is potentially a commercial product for the plant. It can be sold and used instead of natural gypsum. Practically most of the gypsum produced in power plants is utilised in the plasterboard industry. The purity of gypsum limits the amount of limestone that can be fed in the process.

The end-product of semi-dry desulphurisation processes is used in different construction purposes instead of natural minerals, such as in road construction, for earthworks of composting and storage fields, for the filling of mine pits, and for excavation dams in watertight construction.

6.5.4 BAT for liquid fuel-fired gas turbines

For gas turbines firing liquid fuel such as LFO or diesel, the injection of water or steam is considered as BAT for the reduction of NO_X emissions. Nowadays, dry low NO_X premix burners (DLN) are also available for liquid fuel-fired gas turbines. These DLN burners can even be used if liquid fuel and natural gas is fired in the same turbine. DLN burners are only BAT for new turbines were the technique is available on the market for the use in gas turbines burning liquid fuels. SCR can also be used but according to the economic feasibility the application needs to be regarded case by case. For gas turbines using only liquid fuel (for instance, in cases where gaseous fuels are temporarily not available), reference is given to Section 7.5 of this document.

In general, for liquid fuel-fired gas turbines, the use of low sulphur fuel oil is considered to be BAT for the reduction of SO_2.

6.5.5 BAT for liquid fuel-fired (diesel) engines

A diesel flue-gas typically contains about 13 to 15 vol-% O_2 and, therefore, the emission levels associated with the use of BAT are based on an O_2 level of 15 vol-%, as the reference point.

A split view from one Member State appeared about the inclusion of ‘diesel engine’ in this document, because diesel engines are used for power generation, only on the islands which are not interconnected to the mainland grid. Such installations which exceed 50 MW_{th} in aggregated installed capacity are used due to the diesel engines special technical characteristics, which match the peculiarities of the electricity demands of these isolated islands. The installations operate at their full capacity only for a short period of time each year, namely the touristic season (for approximately two months). For the rest of the year, the installations operate at a small part of their capacity (approximately 1/4).

The characteristics of the electricity demand determine the configuration of the installation, i.e. many small engines are needed, because the capacity of the largest unit can only reach approximately 10 – 15 % of the total installed capacity. Also, the power generation equipment needs to be very flexible for quick start-ups, shut-downs and very frequent and quick load variations, low partial load and to possess black – start capability. These features are necessary, due to the great variations in electricity demand in each season, as well as during the day, in an effort to achieve a satisfactory level of efficiency at the same time for certain units in the lot, which must operate at the optimum load.

Also, the needs of the isolated grid for stability are increased, due to increased penetration of wind power generation, encouraged and promoted on the islands. All wind power variations have to be accommodated by the flexible operation of the diesel engines. In addition to the above, the restrictions in the available fuels, as well as the difficulties in fuel supply to the islands, increase fuel costs dramatically.

6.5.5.1 Thermal efficiency

The emissions of carbon dioxide (the most important greenhouse gas) depend on the fuel used and on the efficiency of the prime mover. By maintaining a high efficiency of the reciprocating engine power plant, the CO_2 emissions can be kept at a relatively low level.

Engine driven power plants are fuel flexible and suitable both for decentralised heat and power production (CHP) as well as for larger base load applications. The BAT associated total efficiencies are up to 60 to 70 % in low pressure steam generation. With supplementary firing (with the oxygen content of the engine flue-gas being used as the main 'combustion air' in the burner) a large amount of low pressure or high pressure steam can be generated in an efficient way. In hot water production (outlet temperature typically in range of 80 to 120 ºC), a total efficiency of about 85 % in liquid fuel mode and up to 90 % in gas fuel mode, highly depends on the portion of the engine cooling water energy recovered in the application, can be seen as the BAT associated level. Hot water up to 200 ºC can, of course, be produced by utilising the energy in the flue-gas and a part of the engine cooling energy. Another advantage is the high thermal efficiency (low fuel consumption, and as a consequence low specific CO_2 emission) of the engines. The BAT electrical efficiency (at the alternator terminals) ranges from about 40 to 45 % (depending on engine size) calculated based on the lower heating value of the fuel.

6.5.5.2 Dust and heavy metals emissions

The emission of particles are fuel related. Due to the different temperature and oxygen content of the diesel flue-gas, the electrical properties of the diesel particles are different compared to particles from boiler flue-gas. The ash content is the main parameter, but other parameters such as sulphur and asphaltene contents of the fuel also affect the emission of particles. By using an SCR for NO_X reduction, a very small reduction in particulate matter may also be achieved depending on the fuel type and exhaust temperature.

Because secondary cleaning devices for the reduction of particulate emissions is under development at the moment, for larger diesel engines, the use of engine measures in combination with the use of a low ash and low sulphur fuel, whenever commercially available, can be considered as BAT for reducing particulate emissions.

A large capacity plant can also consist of a number of several aggregates with comparatively small capacities. In this case, each individual aggregate can be equipped with filters for particles especially soot. Dust emissions from engines of up to 1.3 MW fuel input can be reduced below emission values of 20 mg/Nm^3.

The BAT conclusion for the prevention and control of particulate emissions from four stroke engines and the associated emission levels are summarised in Table 6.47. The emission levels of dust from two stroke engines can be higher.

Engine type	Dust-emission level (mg/Nm^3)	Monitoring	Comments
Diesel engine	<30 LFO/diesel <50(1) HFO	Discontinuous once every 6 month	Steady state 85 to 100 % load of the engine. O_2-reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa. Particle filter systems are under development for engines over 5 MWth
A dual fuel engine in back-up fuel mode (diesel oil max. 0.02 wt-% ash)	<30 LFO/diesel <50(1) HFO	Discontinuous once every 6 month	
1	One Member State claimed that dust emission levels from diesel engines burning heavy fuel oil should be increased to 100 mg/Nm^3 at 15 % O_2, because for diesel engines (4-stroke or 2-stroke) this higher value better reflects the dust emissions for HFO and consider the influence of other fuel parameters better apart from the ash content, such as sulphur and asphaltenes content.		

Table 6.47: BAT for dedusting off-gases from four stroke engine plants by primary engine measures

6.5.5.3 SO_2 emissions

At the moment, only a few diesel power stations exist equipped with FGD systems, and even then only for a limited number of operating hours. The investment cost for a FGD plant greatly varies according to the chosen operational method. The operating cost mainly depends on the amount and type of reagent, water, electricity consumptions, maintenance and any end-product disposal costs. Therefore, the use of low sulphur fuel oil or natural gas, whenever commercially available, is regarded as the first choice of BAT. Secondly, if low sulphur fuel oil or natural gas are not available, the use of a secondary FGD system is considered as BAT for reducing emissions of SO_2.

6.5.5.4 NO_X emissions

The application of primary methods and secondary measures, in particular the application of an SCR system is regarded as BAT to reduce NO_X emissions from liquid-fuel-fired engine plants. Primary methods for liquid-fuel-fired diesel engines are:

- the 'Miller concept'
- injection retard
- direct water injection (DWI)
- humid air injection HAM.

During the last decade the NO_X emissions from liquid fuel-fired big diesel- and heavy fuel oil fired engines has been reduced considerably by primary measures on the engine in combination with SCR, compared to the previous values, whilst maintaining the high efficiency of the engine.

A limitation for the applicability of SCR is given for small diesel and two stroke engines which needs to be operated with often varying loads. These unit are operated frequently on isolated systems to be operated for a reduced number of hours only. According to the electricity demand, these engines need to be started up and shut down several times a day.

SCR is an applied technique for diesel engines, but can not be seen as BAT for engines with frequent load variation, including frequent start up and shut down periods due to technical constraints. A SCR unit would not function effectively when the operating conditions and the consequent catalyst temperature are fluctuating frequently outside the necessary effective temperature window. As a result, SCR is part of BAT, but no specific emission levels are associated with BAT in a general sense.

The BAT conclusion for the prevention and control of NO_X emissions are summarised in Table 6.48.

Engine type	BAT	Applicability	Monitoring	Comments
Diesel oil-fired engine plant	Miller-type engine, injection retard, water injection SCR	SCR can be applied to new and existing plants	Continuous	O_2 reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa
A dual fuel engine in back-up mode	Miller-type engine, injection retard, water injection SCR	SCR can be applied also to dual fuel engines for the gas fuel mode and the back-up mode	-	O_2 reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa
Light fuel-fired engine plant	Miller-type engine, injection retard, water injection SCR	SCR can be applied to new and existing plants	Continuous	O_2 reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa
Heavy fuel oil-fired engine plant	Miller-type engine, injection retard, water injection SCR	SCR can be applied to new and existing plants	Continuous	O_2 reference point at 15 vol-%, Nm^3 at 273 K and 101.3 kPa

Table 6.48: BAT associated NO_X levels for liquid fuel-fired engine plants with SCR as BAT

6.5.5.5 CO and hydrocarbon emissions

For the minimisation of air emissions, good maintenance of the engine is regarded as BAT. A diesel engine has low CO and hydrocarbon (HC) emissions. CO emissions are often in opposite to NO_X emissions. CO can be reduced by primary measures aiming at complete combustion. Secondary measures such as oxidation catalysts for CO reduction can also be regarded as BAT.

Oxidation catalysts are not recommended in context with liquid fuels containing sulphur. For engines, CO catalysts are available on the market and are regarded as part of the BAT conclusion. The first combined CO/NMHC catalysts have been installed in some spark-ignited engine plants and running experience is currently being gathered.

6.5.5.6 Water pollution

The engine plant needs only small amounts of water and can thus be operated in locations with restricted water supplies, especially if radiator cooling is applied. Together with the reduced water requirement, is the lower generation of waste water discharge, and thus consequently less thermal pollution to the surrounding watercourse.

6.6 Emerging techniques for the combustion of liquid fuels

Fuel cell applications are expected to be a future energy technique for clean liquid fuels. They may offer improvements in environmental protection and are expected to lead to higher efficiencies (possibly by up to 70 % in the future). Proof of the stability of operation for a qualified lifetime is the main necessity before they can be broadly applied. At the moment, the size of the pilot plants is small compared to LCPs.

7 COMBUSTION TECHNIQUES FOR GASEOUS FUELS

7.1 Applied processes and techniques

7.1.1 Unloading, storage and handling of gaseous fuels

Gaseous fuels are delivered to LCPs via pipeline, either from the gas-well or from liquid natural gas decompression and storage facilities. Natural gas from different wells varies in quality. Often gas clean up may occur at the production site to reduce transport problems in pipelines. Figure 7.1 shows the European natural gas network, indicating the pipelines integrated into the European system. The pressure in the main pipeline systems is 80 bar.

Figure 7.1: European natural gas network
[111, Eurogas, 1998]

The gas supplier usually provides centralised storage capacities for natural gas. At some sites, for existing LCPs, separate storage tanks still exist. Gas storage tanks are often located near to CHP units, but are used for public gas supply. On-site gas storage at LCP sites for new plants is not practised. Distillate is most commonly used as the back-up fuel in such circumstances and is stored on-site.

A range of gases may be used in gas combustion plants. If the pressure of the supply pipeline exceeds the required input pressure of the LCP, the gas needs to be decompressed. This normally takes place in an expansion turbine in order to recover some of the energy used for compression. Waste heat from the power plant can be used to heat up the decompressed gas and thus to increase electricity output. Fuel gas is then transported in pipes to the LCP.

Gas turbines only use clean gases for direct firing. Here also, natural gas may have to be decompressed if the pressure of the pipeline exceeds the required input pressure of the gas turbine. Adiabatic cooling of the expanded gas can be used to cool the fresh air entering the gas turbine's compressor. Fuel gases at atmospheric pressure from other sources have to be pressurised to the necessary input pressure of the combustion chamber of the particular gas turbine.

7.1.2 Gas turbines (GT)

Gas turbines are used for the transformation of chemically bound fuel energy into mechanical energy. They are applied for the production of electrical energy and to drive pumps and compressors. The number of gas turbines used worldwide has grown significantly during the last decade, and nowadays gas turbines are increasingly used for electricity production in base and intermediate loads. This increase may be explained by the abundant supply of natural gas at a favourable price and by the development of a new generation of gas turbines with higher output, efficiency, and reliability. Figure 7.2 shows a breakdown of gas turbines by firing mode worldwide.

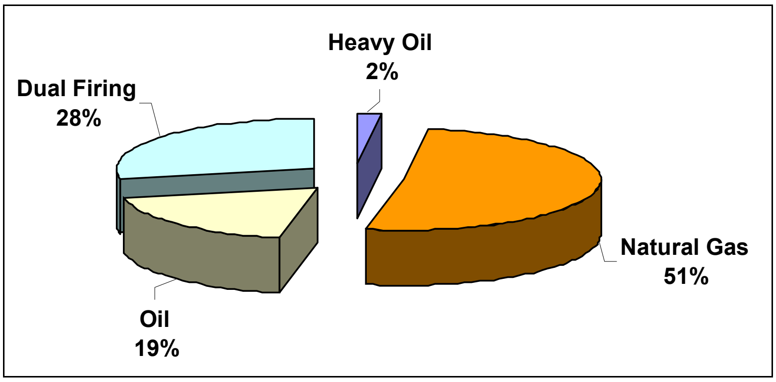


Figure 7.2: Firing mode of gas turbines – worldwide status
[32, Rentz, et al., 1999], [164, Lenk and Voigtländer, 2001]

Gas turbines are used within a wide range of thermal capacities, from small gas turbines at about 100 kW_e up to large gas turbines of 310 MW_e. Gas turbines can be fuelled with various gaseous fuels and liquid fuels. Natural gas is the usual gaseous fuel for gas turbines, but gases with low or medium calorific value are also applied, such as coal gas from coal gasification units, gas from blast furnaces and gas from biomass gasification units. Heavy duty gas turbines are capable of burning a variety of liquid fuels, from naphthas to residuals. Operating with ash-forming fuels, such as crude and residual oils, requires comprehensive treatment systems. The requirements applied for liquid fuels to be fired in gas turbines are described in Section 6.1.7.

Gas turbines are installed in different types of combustion plants such as combined cycle units, co-generation plants and integrated coal gasification units. Aeroderivative gas turbines are available up to 50 MW_e with efficiencies of up to 42 %. They are also largely used on offshore platforms. Heavy duty gas turbines (Figure 7.3) with power outputs from 200 – 300 MW_e can reach efficiencies of up to 39 %.

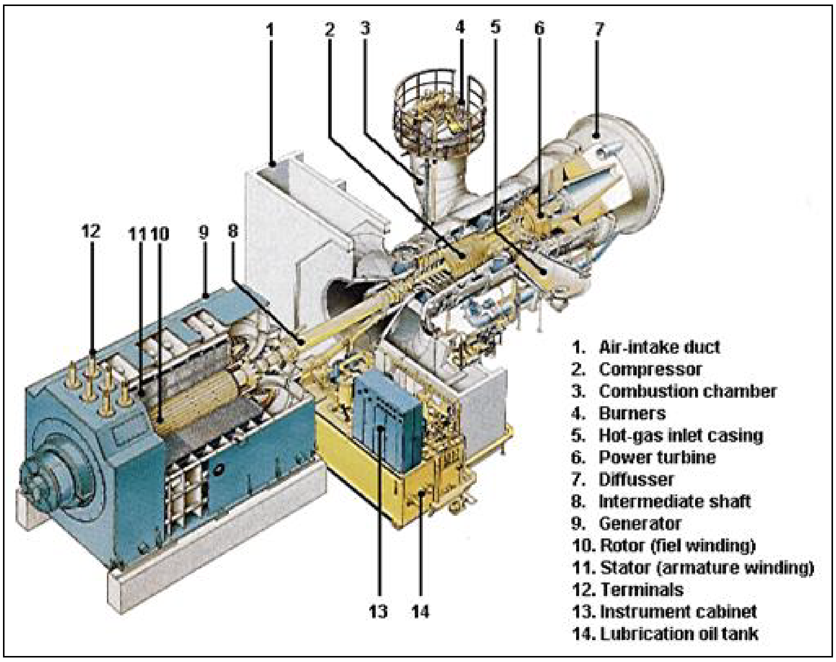


Figure 7.3: Heavy duty gas turbine electricity generating unit
[104, Siemens, 2001]

The application of new gas turbines in combined heat and power units is increasing in an attempt to improve overall efficiency and emissions. As the efficiency of single cycle gas turbines varies from approximately 30 to 42 %, the efficiency of combined cycles can be up to 58 %, while application in a combined heat and power station, fuel utilisation values of 85 % can be obtained. It should be emphasised that the efficiency values mentioned apply to new, clean gas turbines at full load and under ISO conditions. At other conditions, the values may be significantly lower. The rapid development of gas turbines is expected to lead to even higher efficiencies and power output in the future.

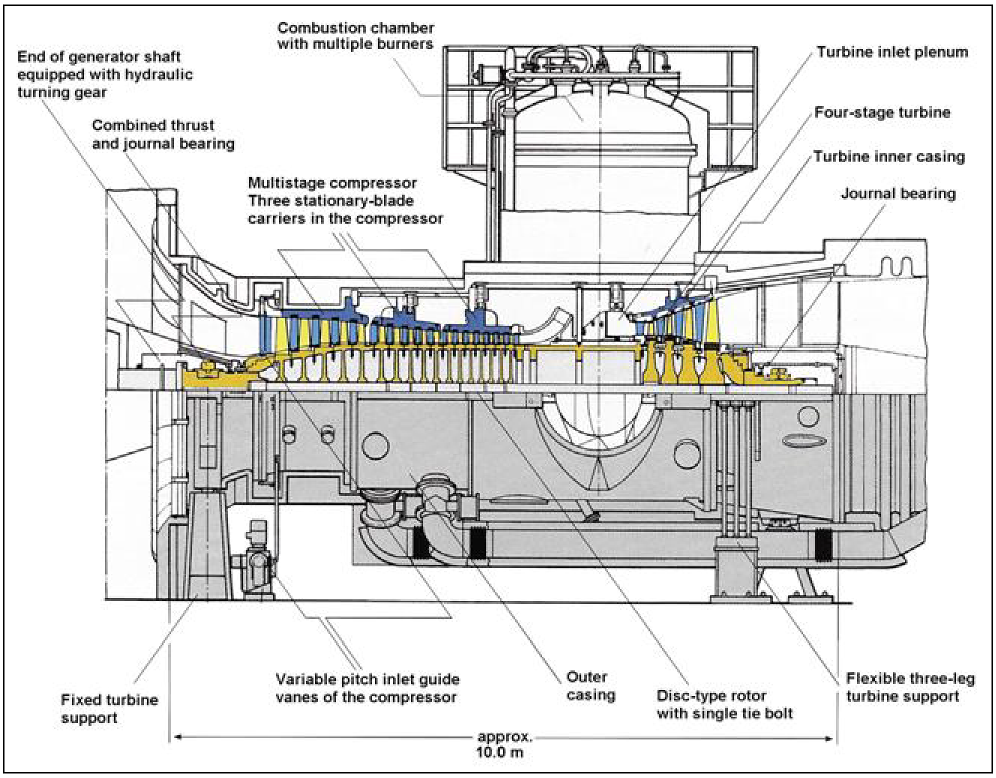


Figure 7.4: Gas turbine (159 MW) with a silo combustion chamber
[104, Siemens, 2001]

A gas turbine consists basically of three elements: a compressor, a combustion chamber and an expansion turbine (Figure 7.4). Ambient air is taken in by the compressor through the air intake system, filtered and then compressed to a pressure of between 10 and 30 bar in aeroderivative or larger industrial gas turbines. Since a gas turbine consumes large amounts of combustion air, the presence of even low concentrations of contaminants in the air can result in a significant fouling of the gas turbine. This can be due to some of the contaminants precipitating on the blades of the compressor, directly affecting the performance of the gas turbine. This effect can be seen in the photographs below, which show the first row of turbine vanes before and after turbine washing [164, Lenk and Voigtländer, 2001].

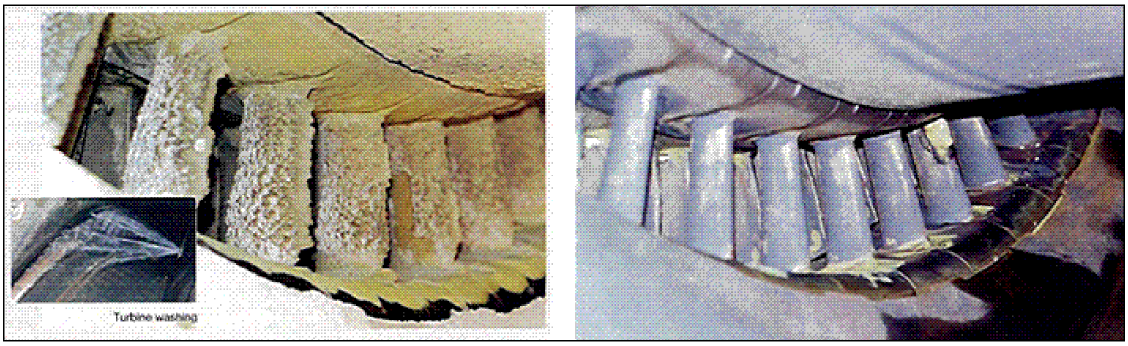


Figure 7.5: First row of turbine vanes before and after turbine washing [164, Lenk and Voigtländer, 2001]

The combustion air is filtered to prevent occurrence of these phenomena. In the combustion chamber(s), fuel and compressed air are burned at temperatures of up to 1235 to 1430 °C (for large gas turbines). After the combustion process, the gas expands through the turbine and generates electric power in the generator, drawing off the power needed to drive the compressors (Figure 7.3).

Gas turbines are designed with one or two shafts. Single-shaft gas turbines are configured with one continuous shaft and, therefore, all stages operate at the same speed. These units are most suited to generator drive applications where a significant speed variation is not required or even not wanted. In some cases, a reduction gear is applied between the gas turbine and the generator.

In a two-shaft gas turbine, the low pressure part of the turbine (the power turbine) is separated from the high pressure part, which drives the compressor. The low pressure turbine is able to operate at a wide range of speeds, which makes it ideally suited to variable speed applications. However, this feature is less important for application in power plants, because the driven equipment (i.e. the generator) has a constant speed during normal operation, related to the grid frequency.

In most heavy duty turbines for land-based operation, proven technology is used from aircraft or steam turbine applications. The materials applied in stationary gas turbines can be classified into three main groups: stainless steels (iron-based), nickel based alloys and cobalt based alloys. In general, the materials adopted for compressors are the same as those applied in the high pressure parts of the steam turbines. Nickel based materials are usually applied for combustor parts. For gas turbine blades, nickel based superalloys are applied because of their good mechanical properties at high temperatures.

As a result of optimising the superalloys with respect to mechanical properties, the corrosion resistance of these alloys is not optimal, especially at higher temperatures. Coatings are applied to improve the corrosion and oxidation resistance of turbine blade materials. Coatings for compressor blades are applied to improve the corrosion resistance (at low temperatures, condensates of moisture and acid solutions are corrosive to the components).

7.1.3 Compression ignition engines

Gas-fired compression ignition engines with a thermal input above 50 MW are rarely applied and thus described only briefly in this document. In the 1960s and 1970s, engine-driven power plants were mostly used for short-time running applications such as emergency, peaking and small-scale power production. Both larger base load engine driven power plants with outputs up to 150 MW_e and decentralised smaller simultaneous heat and power (CHP) production plants exist today. The reason for this trend is the opening-up, privatisation and decentralisation of the electricity markets in many countries, combined with the development, in recent decades, of high efficiency medium speed engines suitable for base load operation. Medium speed diesel engine units with a fuel input of up to 50 MW_{th} or more, gas diesel engines ('high pressure' and 'low pressure(dual fuel)' types) with a fuel input of up to 40 MW_{th} and spark-ignited engines with a fuel input of up to 18 MW_{th} are on the market [63, Wärtsilä, 2000].

7.1.3.1 Spark-ignited engines

A spark-ignited gas-Otto engine often works according to the lean burn concept. The expression 'lean burn' describes the ratio of combustion air and fuel in the cylinder, which is a lean mixture, i.e. there is more air present in the cylinder than needed for combustion. In order to stabilise the ignition and combustion of the lean mixture, in larger engine types, a pre-chamber with a richer air/fuel mixture is used. The ignition is initiated with a spark plug located in the pre-chamber, resulting in a high energy ignition source for the main fuel charge in the cylinder. The burning mixture of fuel and air expands, pushing the piston. Finally, the products of combustion are removed from the cylinder, completing the cycle. The energy released from the combustion of the fuel is transferred to the engine flywheel via the moving piston. An alternator is connected to the rotating engine flywheel and produces electricity. The engine type is designed for use with low pressure gas as a fuel.

7.1.3.2 Dual fuel engines

The dual fuel engine is a new engine type on the market developed for countries where natural gas is available. The engine type is fuel versatile, it can be run on low pressure natural gas or liquid fuels such as diesel oil, heavy oil, bio oils, etc. and it can operate at full load in both fuel modes. In the gas mode, the engine is operated according to the lean-burn principle, i.e. there is about twice as much air in the cylinder compared to the minimum needed for complete combustion of gas. This allows a controlled combustion and a high specific cylinder output without immediate risk of knocking or self-ignition when the process is well controlled. In gas engines, the compression of the air/gas mixture with the piston does not heat the gas enough to start the combustion process, some additional energy therefore, needs to be added and this is arranged by injecting a small pilot fuel stream (diesel oil, etc.). A liquid fuel such as diesel oil, etc. has a lower self-ignition temperature than gas and the heat in the cylinder close to the top position is enough to ignite the liquid fuel which, in turn creates enough heat to cause the air/gas mixture to burn. The amount of pilot fuel ranges from 1 to 5% of the total fuel consumption at full load. The engine works according to the diesel process in liquid fuel mode and otto-principle in gas mode. The burning mixture of fuel and air expands, which pushes the piston. Finally the products of combustion are removed from the cylinder, completing the cycle. The energy released from the combustion of fuel is transferred to the engine flywheel via the moving piston. An alternator is connected to the rotating engine flywheel and produces electricity.

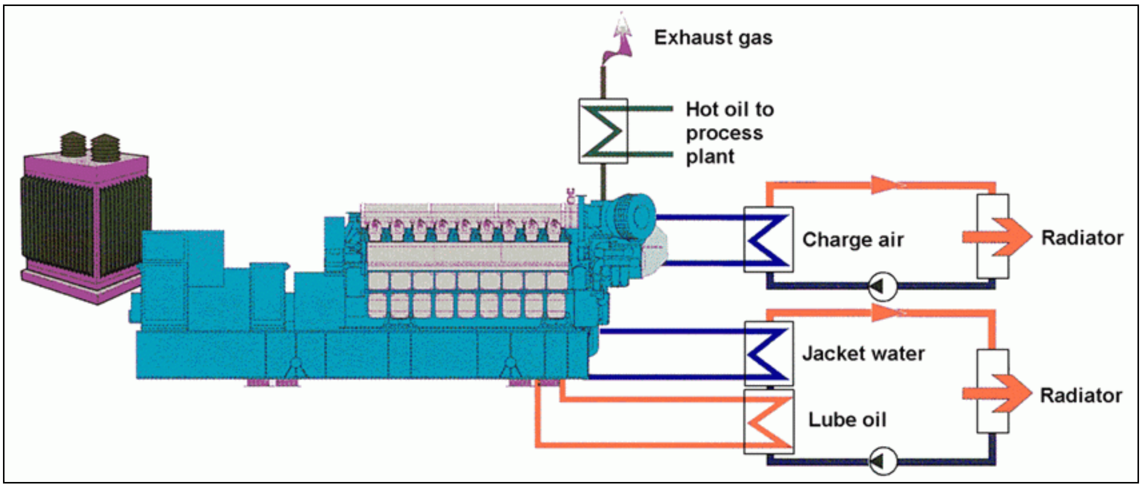


Figure 7.6: Natural gas fired engine
[149, Wärtsilä NSD, 2001]

7.1.3.3 High pressure gas injection engines

High pressure gas injection engines are operating according to the diesel process in both liquid and gas fuel modes. In gas mode, a pilot fuel oil (HFO, etc.) (typically 3 – 5 % of the total fuel heat input) and a high pressure gas at about 350 – 400 bar pressure are needed. The engine can operate at full load both in liquid and gas fuel modes. High pressure gas diesel engines up to about 40 MW_{th} or 20 MW_e are available on the market.

7.1.3.4 Co-generation using gas engines

A common heat recovery application for combined heat and power plants with gas engines, is to generate low pressure steam for industrial purposes. The pressure range is usually from 3 to 16 bar, but higher steam pressure and extended steam production can be achieved with supplementary firing or auxiliary fired boilers. Steam at 8 bar is well suited for desalination and absorption chillers, while certain industrial processes might require higher steam pressures. The ratio between electricity and heat consumption very much depends on the application of the particular industrial facility. A typical CHP plant generating steam at 7 to 8 bar, typically has a total fuel utilisation of about 60 – 70 % when only steam is produced and up to 90 % for hot water generation. The total efficiency depends on the amount of heat of the engine cooling water circuit that can be recovered. The steam generation system has an auxiliary oil or gas fired boiler in parallel with the engine exhaust gas boiler and is flexible in applications where large amounts of low steam pressures are required. The heat in the engine exhaust gas can also be either directly or indirectly (via an air-preheater – 'LUVO') be utilised for drying, preheated burning air, etc. purposes dependent on the industry process requirements.

The second solution for boosting the steam generating capacity is to equip the exhaust gas boiler with supplementary firing. For larger spark-ignited gas engines, the oxygen content is typically 11 to 12 vol-% and for a high pressure gas diesel engine, often higher. This oxygen can be used as the main combustion air for supplementary firing. The system also makes it possible to generate high pressure steam and it has a good thermal efficiency for the additional fuel for the supplementary firing. So far, there are only a few reciprocating engines which exist equipped with supplementary firing, due to the challenges of combining the combustion flame with the pulsing of the engine exhaust gas and the relatively low oxygen content of the flue-gas [63, Wärtsilä, 2000].

An interesting CHP concept is the feed-water combined cycle where the waste heat from the engine exhaust gas and cooling circuits are used for increasing the efficiency of an existing, e.g. steam boiler plant. The electrical efficiency of a gas engine plant can be raised by equipping the plant with a steam turbine. Steam turbines most used in this application are single stage condensing turbines and the steam pressure typically applied is 12 to 20 bar.

7.1.4 Gas-fired boilers and heaters

Power plant gas-fired boilers are similar to the oil boilers described in Chapter 6. When designed for gas burning only, the combustion chamber is slightly smaller but, in most cases, these boilers are designed for burning liquid fuel too, in emergency situations or for co-combustion. The heat from the combusted fuel is used for the production of superheated steam, which expands in a steam turbine that drives a generator. In order to efficiently convert the energy from the steam to electricity, modern gas-fired boilers use supercritical steam parameters, which produces plant efficiencies of up to 48 % in the condensing mode and fuel utilisation figures of 93 % at combined heat and power production. The application of double reheat and increase of the supercritical steam parameters to 290 bar and 580 °C can reach these high efficiencies.

Another use of gas-fired boilers is as auxiliary boilers, to provide start-up facilities, including cold start possibilities in different types of thermal power plants. Auxiliary boilers are also applied in most power stations for heating buildings and equipment during standstill periods. These boilers are designed to produce slightly superheated steam at relatively low pressure. These small boilers are not addressed in this document.

There are a lot of gas-fired boiler installations in process industries and in district heating systems. Most of them are medium sized installations (i.e. from 50 to 300 MW). For these levels of heat output, increasing constraints on SO_2 and NO_X emissions leads to a larger utilisation of naturel gas. A large part of these boilers could also be fed with liquid fuel in emergency situations and for co-combustion.

The burners of the boilers are, in general, arranged in several levels in the walls (front firing or opposed firing) or at several levels tangentially in the four corners of the boiler. Firing systems for gas-fired boilers are similar to coal- or oil-fired boilers.

Gas burners are also used in process heaters, which are sometimes referred to as process furnaces or direct-fired heaters. These are heat transfer units designed to heat petroleum products, chemicals, and other liquids and gases flowing through tubes. The liquids or gases flow through an array of tubes located inside a furnace or heater. The tubes are heated by direct-fired burners that use standard specified fuels such as HFO, LFO, and natural gas, or the by-products from plant processes, although these can vary widely in composition. Gaseous fuels are commonly used in most industrial heating applications in the US. In Europe, natural gases also commonly used along with LFO. In Asia and South America, HFO are generally preferred, although the use of gaseous fuels is on the increase. More detailed information on gas and liquid fuel-fired heaters is available in Sections 6.1.4 and 6.1.10.2.

Gaseous fuels are used as support or start-up fuel for coal-, lignite- or oil-fired boilers. These combustion techniques are described in Chapters 4 and 6.

7.1.5 Combined cycle combustion

Today, about half of the new power generation capacity ordered consists of combined cycle power plants. At these plants, a gas turbine is combined with a steam turbine to generate electricity. For technical and cost reasons, the only practicable combined cycle gas turbine (CCGT) fuels are natural gas and light fuel oil (as back-up fuel). Figure 7.7 shows a three-dimensional drawing of a gas turbine combined cycle power plant built in Finland.

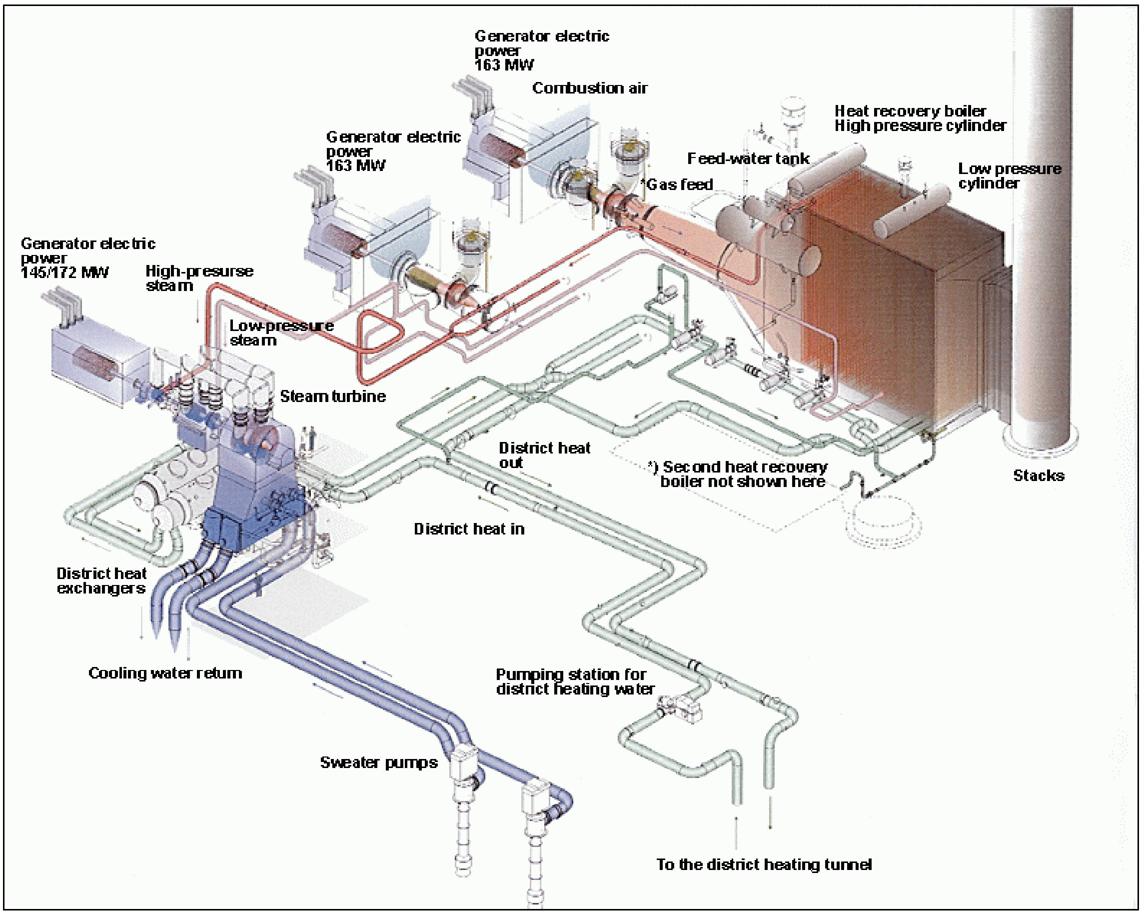


Figure 7.7: Gas turbine combined cycle power plant
[96, Helsinki Energy, 2001]

At combined cycle power plants, gas turbines generate power at an efficiency of approx. 33 - 38 %. The gas turbine exhaust gas typically has a temperature of 430 – 630 °C, depending on the turbine type and on ambient conditions. This hot gas is led to a heat recovery steam generator (HRSG), where it is used to generate steam, which then expands at a steam turbine power plant in principle similar to a condensing power plant. The great attractions of a CCGT plant are its low heat rate and its low investment cost, which have made CCGT competitive, despite the high cost of the natural gas fuel. In the past 20 years, the heat rate of a CCGT plant has decreased from 2.2 to 1.7, i.e. the LHV efficiency has grown from 45 to 58 %. Gas turbines are currently still undergoing rapid development, and a CCGT heat rate below 1.67 (efficiency over 60 %) should be possible in the near future. In today's CCGT plants, approximately 2/3 of the output comes from the gas turbine and the remaining 1/3 from the steam turbine. However, recent commissioning experience suggests that there are difficulties in achieving the very high efficiencies forecast.

Because less than 1/3 of the oxygen in the gas turbine inlet air is consumed for combustion in the gas turbine combustor, supplementary firing of fuel in the gas turbine exhaust gas is possible. In modern CCGTs, this causes a slight increase in the power generation heat rate. However, in industrial co-generation, it is frequently used as a means of controlling HRSG steam generation independently of the gas turbine output. In co-generation applications, supplementary firing also improves the overall efficiency of heat and power generation.

Because both natural gas and light fuel oil are very clean fuels and allow a practically complete combustion in gas turbine combustors, there are no problems with ash, char or SO_2 at CCGT plants. The only problem is NO_X, which, at modern plants, is controlled by using special low NO_X burners and sometimes SCR added to the HRSG. In older burners, the NO_X can be controlled by water or steam sprays into the burners, but it happens at the expense of the plant heat rate.

Gas turbines are inherently very noisy, therefore they are built into special noise attenuation enclosures, with silencers integrated into the gas turbine air intake and exhaust gas outlet channels.

Figure 7.8: Recently built gas turbine combined cycle power plant in Belgium

In the power generation sector, several gas turbine process configurations can be distinguished for the use of the energy contained in the gas turbine off-gas:

- combined cycle without supplementary firing (HRSG)
- topping cycle (hot wind box).

7.1.5.1 Combined cycle without and with supplementary firing (HRSG)

Within this process, fuel is exclusively fed into the combustion chamber and no additional firing takes place in the recovery steam generator. The steam generated by the heat recovery steam generator from the thermal energy contained in the gas turbine exhaust gas is further used to produce electricity via a steam turbine. This type of combined cycle gas turbine achieves efficiencies as high as 58.5 %. The fuel generally used is natural gas or light oil, but the use of coal in a gasification plant, that will need to be installed upstream of the gas turbine, is also possible (see Chapter 4). A schematic drawing of the combined cycle without supplementary firing (HRSG) technology is given in Figure 7.9.

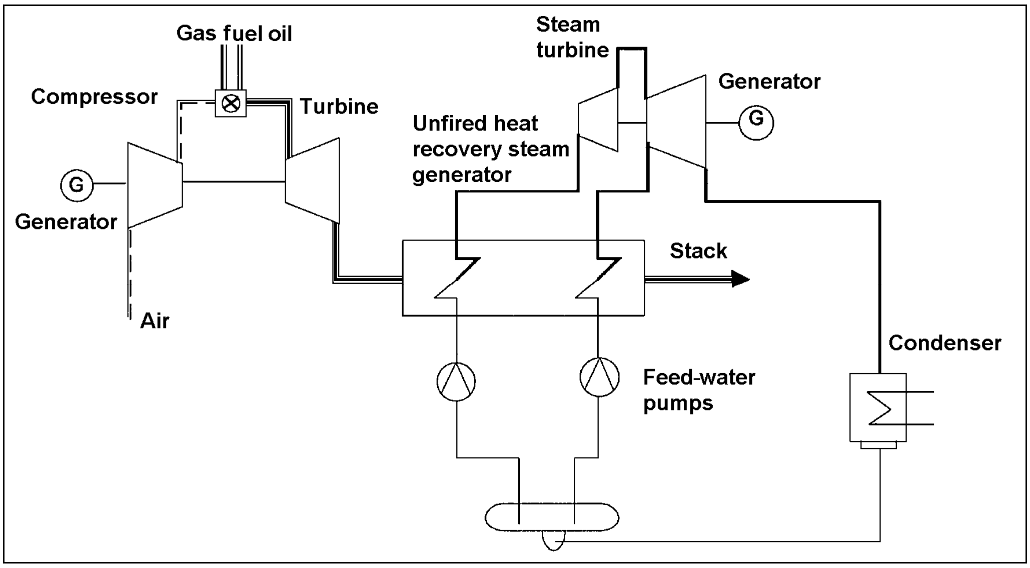


Figure 7.9: Schematic of a combined cycle power plant with a heat recovery steam generator (HRSG)
[32, Rentz, et al., 1999]

A multishaft configuration is applied mostly in phased installations in which the gas turbines are installed and operated prior to the steam cycle operation and where the intention is to operate the gas turbines independently of the steam system. Multishaft combined cycle systems have one or more gas turbine generators and HRSGs that supply steam through a common header to a separate single steam turbine generator unit.

Exhaust gas bypass systems, which are applied in multishaft combined cycle systems to provide fast start-up and shutdown and flexibility of operation are not required with singleshaft systems or with multishaft systems with one gas turbine and one steam turbine

HRSGs are generally heat-exchangers of the convection type, provided with fin tubes, and which exchange the heat from the exhaust gases to the water steam cycle. The exhaust gases are cooled down as low as possible to achieve the highest efficiency. The temperature is restricted by the risk of corrosion caused by a possible condensation of the acid (sulphur) products from the exhaust gases. Exhaust temperatures of 100 °C are considered normal.

HRSGs are constructed in horizontal (with natural circulation of the evaporation system) and vertical (with forced circulation of the evaporation system) configurations. The choice depends on the space requirements and/or the client preferences. Both types are widely used.

7.1.5.1.1 Combined cycle with supplementary firing (topping cycle)

In a topping cycle, the heat of the exhaust gases of the gas turbine is used as combustion air in a conventional power plant with coal or gas fired steam boilers. Several options for integrating this cycle with a conventional power plant process are possible. Although this integration is feasible in new designs, topping cycles have typically been applied in the past as repowering options to improve the efficiency of existing plants (see example 6.2.3.1 in Chapter 6) and/or to increase the heat supply capability of co-generation plants. Various types of topping cycle combined gas turbines are in use in application with outputs of up to 765 MW_e (1600 MW_{th}), and can achieve efficiencies of up to 48 %. A schematic drawing of this technology is shown in Figure 7.10.

Figure 7.10: Schematic of a topping cycle combined power plant
[32, Rentz, et al., 1999]

In a topping cycle (combined cycle with supplementary firing), the air preheaters that heated the inlet air are not needed and should be removed. A gas turbine is usually selected with approximately the same exhaust gas flow as the design combustion airflow of the boiler. Because of the lower oxygen content of the exhaust gases of the gas turbine (in comparison to normal combustion air), less fuel can be combusted in the existing boiler. This results in a lower average temperature of the boiler and consequently a lower steam production in the boiler. The temperature of the flue-gas at the outlet of the radiation part of the boiler will be about the same as in the existing situation. This results in excess heat at lower temperatures. To use this excess heat, a high pressure and a low pressure economiser have to be installed in the boiler. In these economisers (parallel to the existing feed-water preheaters) part of the feed-water will be preheated and, therefore, the amount of extraction steam from the steam turbine will decrease.

A two-stage combustion process can also be created by using exhaust gases of the gas turbine in the existing boiler and resulting in a considerable reduction of NO_X emissions. In one case example, a reduction of NO_X emissions of 50 % has been achieved in the Netherlands.

The electrical capacity of the gas turbine is 20 – 25 % of the total capacity of the power plant.

7.1.5.1.2 Topping cycle with feed-water heating

This process configuration is a combination of the two combined cycles mentioned above. Here, part of the condensate and of the feed-water is preheated in the heat recovery steam generator. The gas turbine or reciprocating engine heat recovery steam generator is linked to the steam turbine/steam generator but only on the water/steam side; a replacement of the combustion air by the gas turbine or reciprocating engine exhaust gas does not, therefore, take place. Reciprocating engines are suited for low pressure feed-water preheating.

By using feed-water heating, the prime mover (gas turbine or reciprocating engine) exhaust gases are cooled in the heat-exchangers by preheating the feed-water. In general, two heat-exchangers, (or strings) one each for low pressure and high pressure feed-water heating, are installed. The heat-exchangers are equipped parallel to the existing (steam fed) feed-water preheaters.

Heat extractions from the prime mover can be eliminated or reduced, which thus results in an increase in the electrical power output of the prime mover. This implies that the heat in the exhaust gases of the prime mover contributes fully to the electrical power output and efficiency of the unit. It appears that the best solution with feed-water heating will be obtained with prime mover with a high efficiency and enough heat capacity to achieve the complete feed-water heating of the bottoming cycle.

The increase in power production is, however, limited by the flow capacity of the steam turbine and by the power rating of the generator. The efficiency improvement with this option is about 2 – 5 % dependent on the prime mover and the existing steam turbine capacity.

A comparison of the capacity of the preheating system of the unit with the heat available in the gas turbine exhaust gases sets the number of prime movers required and the ultimate increase in heat capacity.

The increased flexibility (electrical power versus thermal heat production) is an important advantage gained by the modifications described. The steam plant can operate independently of the prime mover. The flexibility, however, is limited by the maximum allowable flow through the low pressure steam turbine.

Because a topping cycle with feed-water heating does not affect the combustion process of the boiler, the boiler emissions are also unaffected. Total emissions are influenced by the contribution of the prime mover exhaust gases.

7.1.6 Co-generation (CHP)

Only 40 – 60 % of the fuel energy (measured as the fuel lower heating value LHV) can be converted into electric power at electricity-only power plants. The rest is lost as low temperature waste heat into the air or water or both. Because a lot of heat is also needed by the end users in space heating and many industrial processes, the question arises as to how this rejected heat of condensing power plants can be made useful. The thermodynamic answer to this is quite simple: raise the temperature of the rejected heat to the useful level required, e.g. to 70 – 120 ºC for space heating and 120 – 200 ºC for industrial processes. However, this happens to the cost of power generation.

Co-generation is a means of improving the energy efficiency by influencing the energy supply system structure. In every case, co-generation can save fuel compared to the separate generation of heat and power from fossil fuels. If the local heat load is big enough, and the co-generation plant consequently big enough, co-generation can also save money. Technically, all power plants can be modified for co-generation. The suitability of applying a gas turbine in a co-generation plant is partly related to the relatively low investment costs and the high cycle efficiency it offers.

The heat from the gas turbine exhaust gases is used for steam production in a heat recovery steam generator (also called a waste heat boiler). The steam can be used fully for electricity production, as in the combined cycle, or can be extracted partially (or sometimes fully) and used for steam supply to consumers, who can then use the steam in their own processes or for other purposes such as district heating or seawater desalination.

There are many possible configurations to meet the specific plant requirements. Depending on the demand for heat and power, the most common are:

- gas turbine with a heat recovery steam generator and supply of all the generated steam to steam consumers
- gas turbine with a heat recovery steam generator with back-pressure steam turbine, and supply of all the generated heat to steam consumers
- gas turbine with a heat recovery steam generator with steam extractions to consumers and/or the use of extraction steam for other heating purposes and a vacuum steam condenser. This design usually gives more flexibility in the power/heat ratio
- steam injected gas (STIG) cycles in which steam is also generated by the exhaust heat but partly injected to the gas turbine. These are used primarily with aeroderivative gas turbines without the application of a steam turbine. These cycles are mainly applied in co-generation applications with intermittent process steam demands.

An important measure of a co-generation power plant is its power/heat output ratio. Obviously, because electric power can be economically two to four times as valuable as heat, it can be preferable to have as high a power/heat ratio as possible in combination with a low overall heat rate. Here again, the laws of physics set their limits. As explained above, the higher the temperature level of the recovered heat, the less power and more heat is gained from the process. In case a high power/heat ratio is requested or required in this respect, the combined cycle (CCGT) is far more favourable than the conventional steam process. At a condensing CCGT, 2/3 of the power output comes from the gas turbine, and the co-generation-related power loss only occurs in the steam turbine producing the other 1/3 of the output. The power/heat output ratio of a CCGT at nominal load can be 1.1 in district heating applications and 0.9 in the pulp and paper industry, while the figures in steam only co-generation are 0.6 and 0.3 respectively. The annual average figures are typically clearly lower, due to, among others, part load operation and start-up/shutdown cycles.

For co-generation to compete successfully in the market, a high price and demand of electricity and a big enough local heat demand are determining parameters required. For a small power and heat demand, the plant size may remain under the limit of economic competitiveness.

	Power generation heat rate (1)	**Power to heat ratio (2)**	**Total co-generation system heat rate (3)**	**Separated system heat rate; coal (4)**	**Separated system heat rate; CCGT (5)**
Conventional coal condensing	2.3				
CCGT condensing	1.8				
Industrial conventional co-generation (6)	5.0	0.28	1.1	1.36	1.25
Industrial CCGT co-generation	2.4	0.9	1.15	1.67	1.43
DH conventional co-generation	2.9	0.6	1.1	1.55	1.36
DH CCGT co-generation	2.1	1.1	1.1	1.73	1.47
Heat only boilers/coal			1.1		
Heat only boilers/HFO			1.1		
Heat only boilers/gas			1.07		

Notes:
1) Fuel input (LHV)/Net power output
2) Net heat output/Net power output
3) Fuel input (LHV)/(Net power + heat output)
4) Combined heat rate of producing separately in conventional coal condensing plants and heat only boilers (HR = 1.1) the same amounts of power and heat as in the cogenerating system. To be compared with the HR indicated in row 3
5) Combined heat rate of producing separately in CCGT condensing plants and heat only boilers (HR = 1.1) the same amounts of power and heat as in the cogenerating system. To be compared with the HR indicated in row 3
6) Live steam 80 bar 480 °C; back-pressure 4 bar

All figures refer to nominal full load operation.

Table 7.1: Indicative comparison of co-generation with separate power and heat generation [59, Finnish LCP WG, 2000]

In Table 7.1, the total system heat rates (the final three columns on the right) are comparable in each row. They tell how much fuel is needed in a co-generation system and in a separated system with the same power and heat outputs, but with heat and power generated separately. It can be seen that, in each case, the separated system – whether conventional or CCGT-based – clearly consumes more fuel than the co-generation system providing the same energy service. When the comparison basis is conventional condensing power, the reduction in fuel consumption by co-generation ranges from 20 % for the conventional industrial co-generation to 57 % for the district heating CCGT co-generation. If CCGT condensing is assumed for the separate power generation, the savings are smaller, 12 % and 34 % respectively. These figures are quoted only to give a general idea of fuel savings through co-generation; the actual figures always depend on the specifics of each project and the energy supply system of which it is a part.

For co-generation to compete successfully in the market, a high electricity price and a big enough local heat demand are required. For a small heat demand, the plant size remains under the limit of economic competitiveness. Big local industrial heat loads typically exist in the pulp and paper industry, in refineries and in the chemical industry and, in some cases, in the food and textile industries. See also Section 7.1.3.4 'co-generation using gas engines' for reciprocating engine information.

Cheng cycle

In the 'Cheng cycle', the heat of the exhaust gases from a gas turbine is used for steam generation on one pressure level, which is fully injected into the gas turbine. In practice, the Cheng cycle is applied in combined heat and power (CHP) units giving a normal steam supply to users, with a varying heat demand. In situations where no heat or less heat is required the generated steam can be used for electric power generation. It can be noted that make-up water is required for the steam generation, which has to be considered as an overall loss due to its discharge to air together with the exhaust gases. The efficiency increases with decreasing compressor ratio. A turbine efficiency of more than 50 % at a turbine inlet temperature of 1200 °C is calculated [58, Eurelectric, 2001].

7.1.7 Control of emissions to air from gas-fired turbines and combined cycles

7.1.7.1 Abatement of dust emissions

Fuel dust contained in natural gas is washed out at the production site if necessary. Dust or particulate matter emissions from gas turbines burning natural gas are not an environmental concern under normal operation and controlled combustion conditions.

Other gases, such as the by-products of chemical plants, can contain dust. These gases are required to meet different emission limit values compared to natural gas and must be burned or co-combusted in power plants equipped with primary and secondary measures to reduce the dust emissions if these limits cannot be met.

7.1.7.2 Abatement of SO_2 emissions

Fuel sulphur in natural gas in the form of H_2S is washed out at the production site. Thus, fuel qualities are obtained which directly meet SO_2 emission limit values for all applications. Other gases, e.g. as by-products of chemical plants, can contain sulphur. These gases are required to meet different emission limit values compared to natural gas and must be burned or co-combusted in power plants equipped with FGD technology if these limits cannot be met.

7.1.7.3 Abatement of NO_X emissions

7.1.7.3.1 Water or steam injection

Since dry low NO_X combustors (DLN) have reached an acceptable state of development, water/steam injection is now used in Europe, although only to a minor degree so far, as a NO_X reduction measure. However, for existing installations, it is the most easily applicable technology, and may be applied in combination with other NO_X abatement measures. In Canada, about half of the gas turbines with NO_X control are equipped with steam/water injection.

Water/steam injection can be performed either by the injection of a mixture of fuel and water or steam or by the injection of water or steam through nozzles directly into the combustion chamber. The evaporation or superheating of steam requires thermal energy, which is then not available to heat the flame. Thus, the flame temperature decreases and NO_X formation also reduces. As can be seen from Figure 7.11, the emission reduction rate strongly depends on the amount of water or steam used. In order to reach high emission reduction rates, large amounts of water or steam are necessary; sometimes the amount of water or steam injected is higher than the amount of fuel burned. A higher emission reduction rate can be achieved with water than with steam (for a given water or steam-to-fuel ratio), which can be explained by the fact that more energy is required to evaporate the water (in practice approximately twice as much steam is necessary to achieve the same NO_X emission reduction). Water injection is often used when steam is not available, e.g. in simple cycle applications and in pipeline compression, whereas steam injection is usually preferred on natural gas-fired combined cycles, where steam is readily available from the exhaust heat recovery system.

The steam, or water, injected into gas turbines needs to be of very high purity, which requires the use of a high quality water treatment plant, which in turn may create a liquid effluent requiring disposal. Also, the steam or water needs to be injected at high pressures, usually 20 bar or greater. The use of steam or water injection may also reduce the life expectancy of a gas turbine.

Emission reduction rates of between 60 and 80 % can be achieved but without limiting CO. If CO emission limit values are observed, NO_X reduction rates between 40 and 60 % can be achieved. The steam/water to fuel ratio depends on the gas turbine type (e.g. for flame) and it varies between 1 and 1.2. NO_X emissions can be reduced to approximately 80 – 120 mg/Nm^3 (at 15 % O_2). The reduction rates by steam or water injection are presented in Figure 7.11.

The injection of water or steam has an influence on the general gas turbine parameters, such as the output, efficiency, and the exhaust mass flow. For example: the efficiency of a gas turbine is reduced through water/steam injection, and flame stability problems can be observed at high water to fuel ratios [32, Rentz, et al., 1999].

The investment costs for retrofitting gas turbines with water or steam injection can vary widely. These costs are mainly related to the water conditioning and injection devices used. The additional operating costs incurred by the water/steam injection are due to an increased fuel consumption.

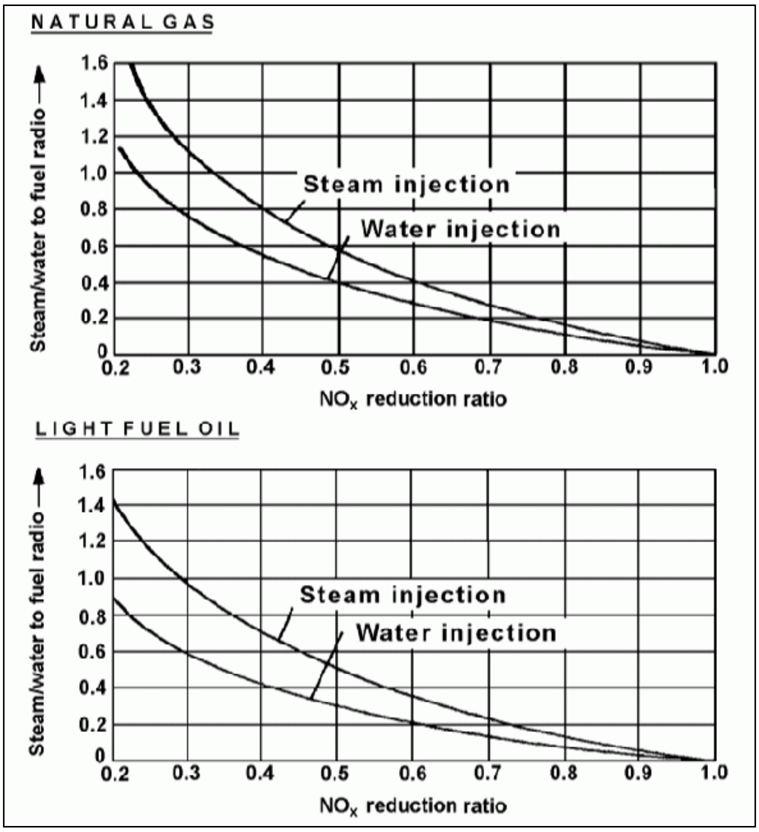


Figure 7.11: NO_X reduction by steam or water injection
[32, Rentz, et al., 1999]

Some major drawbacks of this NO_X abatement technique are the increased emissions of CO and hydrocarbons, a decrease in the thermal efficiency of the installation, and an increase in fuel consumption. Steam injection causes a greater efficiency loss than water injection (3 – 4 % for water injection). Furthermore, direct injection of water or steam results in a higher material stress (small fissures can occur on the material surface due to temperature shock) than injection of a fuel/water or steam mixture. As a consequence, the latter alternative is preferred. [32, Rentz, et al., 1999].

The emission levels can vary a lot, depending on the load of the turbine. In many installations, the steam can be produced only in higher loads, which means that emissions will be reduced only after this base load level has been reached. This makes steam injection of little use for gas turbines with lots of load changes. A steam injection retrofit for a 140 MW_{th} gas turbine costs about EUR 1.7 million.

The injection of water or steam to reduce NO_X can only be carried out to a certain limit. If the steam flowrate injected in the fuel burner is too high (typically the gas turbine supplier fix a limit on steamflowrate/fuel gas flowrate = 1.2), the effects on the compressor are relevant. The amount of steam (or water) can also be responsible for trouble in the combustion chamber (burners, flow sleeves, liners, transition pieces) with particular effect on lifetime and risks of failure with damages to the downstream turbine section. In addition, the increase of water concentration in the exhaust flow from the combustion chamber to the turbine section has an impact on the integrity of blades and nozzles. In fact, the heat exchange coefficient from the exhaust flow to the surface of the nozzles or blades is proportional to the water concentration. So if the gas turbine runs with a large amount of steam or water in order to control the NO_X, mechanical damage and a efficiency reduction may occur, increasing the maintenance costs and the risk of failure.

The injection of water or steam requires a preparation of water used for the process. At sites where steam or water is not used a for other requirements, the investment and operation costs are high. In the cases where gas compressor stations – with a size capacity of between 20 and 250 MW thermal input, with changing operation conditions and with low operating hours per year – are situated at remote sites, the total costs are high. Furthermore, for existing gas turbines, the conversion of the burning system of a gas turbine to a steam or water injection system requires an amount of changes in the design and the layout of the gas turbine. This technology is not appropriate for the gas transmission system of Europe.

7.1.7.3.2 Dry low NO_X (DLN) technologies

Currently, dry low NO_X combustors are applied for large gas turbines, and seem to be becoming more widespread in small facilities (e.g. gas turbines with capacities even below 20 MW_e). DLN technology has also recently been applied to gas turbines operated offshore (see also Sections 7.1.12 and 7.5.5).

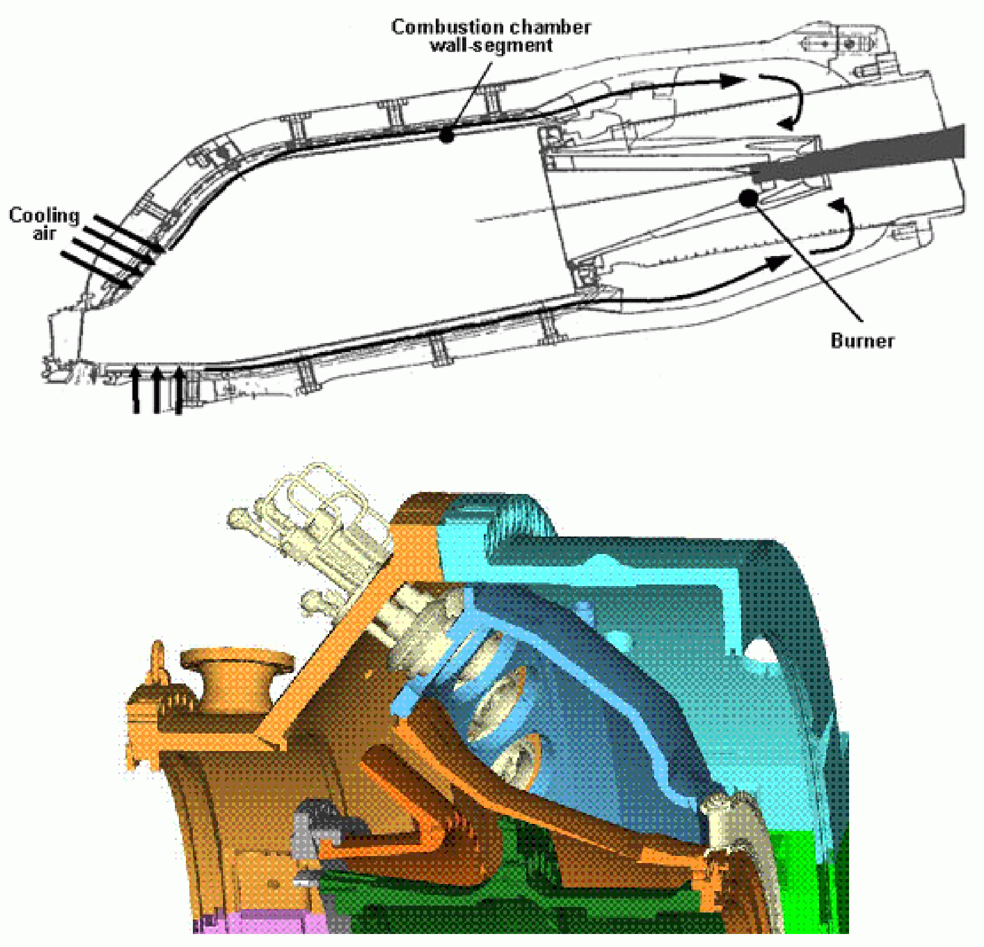


Figure 7.12: Schematic of a DLN combustion chamber

The basic characteristic of dry low NO_X combustors (e.g. Figure 7.12) is that the mixing of the air and fuel and the combustion both take place in two successive steps. By mixing combustion air and fuel before combustion, a homogeneous temperature distribution and a lower flame temperature are achieved, resulting in lower NO_X emissions. Currently, dry low NO_X combustors represent a well established technology, especially for gas turbines using natural gas. Further developments are necessary for gas turbines utilising fuel oils: as, in these turbine operations, not only does premixing of the air and fuel have to be carried out before combustion, but so does evaporation of the liquid fuel. As the particle size has an impact on the evaporation velocity, current research is focusing on developing more efficient atomiser systems. At a Swedish gas turbine power plant, hybrid burners have been operated on light fuel oil in premix mode for almost two years: a considerable NO_X reduction has been achieved, but achieved values are not as low as for the combustion of natural gas. DLN systems for dual fuel-fired (gas/gasoil) GTs are also under development. It is understood from one manufacturer that such dual fired DLN systems are now available and have been tested.

Dry low NO_X combustion systems are very effective and reliable. Today, almost all gas turbines in industrial use are equipped with dry low NO_X systems. Modern dry low NO_X burner retrofits cost approx. EUR 2 million for a 140 MW_{th} gas turbine. Due to their high efficiency, new burners are very economical to operate, especially as there are no great losses of energy from fuel losses, or in the form of hydrocarbons, etc. The investment costs are approx. 15 % higher and maintenance costs are about 40 % higher than non-DLE gas turbines. Dry low NO_X combustion is very model-specific, i.e. each manufacturer develops the technology for each model where there is enough demand to justify the research necessary to develop it. For older models or models with low demand for the technology, it may not be available. Also, earlier versions of the technology may have slightly higher NO_X levels than recently developed versions.

7.1.7.3.3 Selective catalytic reduction (SCR)

Many gas turbines currently use only primary measures to reduce NO_X emissions, but SCR systems have been installed at some gas turbines in Austria, Japan, the Netherlands and in the US (especially in California). It is estimated that approximately 300 gas turbines worldwide are equipped with SCR systems. Further applications of SCR technology at gas turbines are planned in Denmark and Italy [32, Rentz, et al., 1999]. Figure 7.13 and Figure 7.14 demonstrate how SCR catalysts are applied within the CCGT concept, first in a horizontal HRSG and secondly in an installation with a vertical flow set-up [161, Joisten, et al.,].

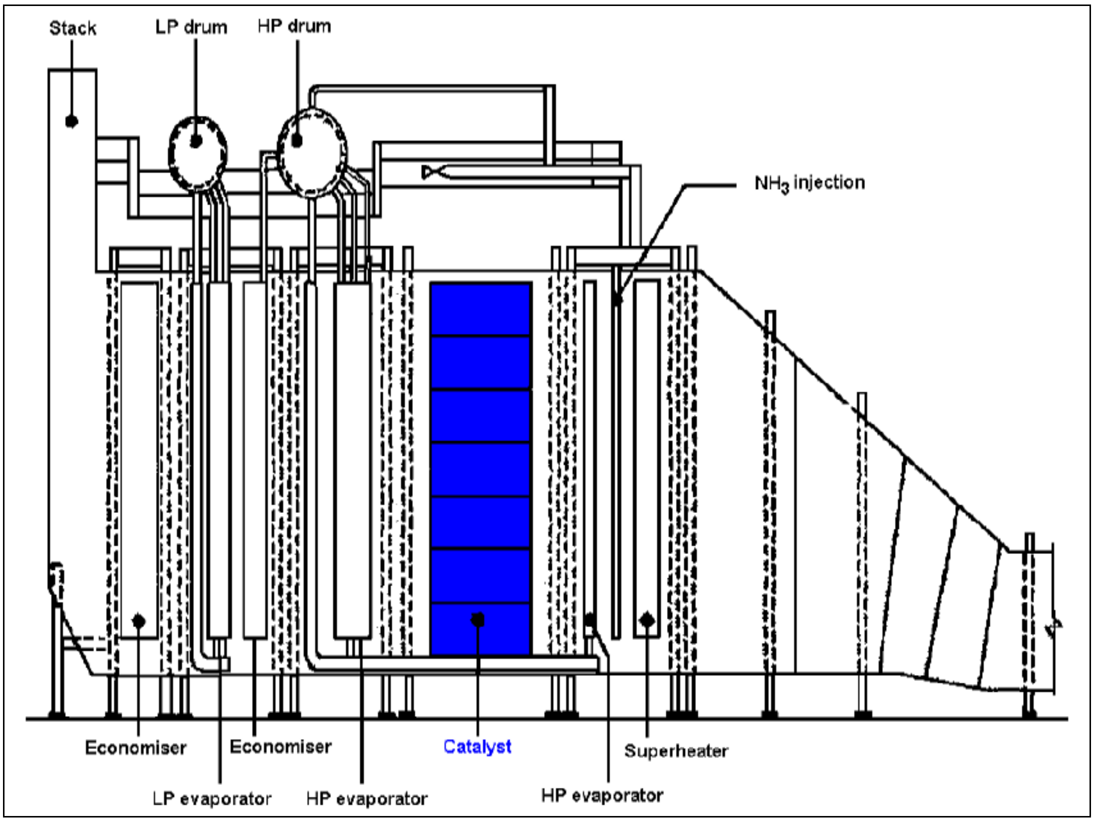


Figure 7.13: HRSG design and SCR installation
[161, Joisten, et al.,]

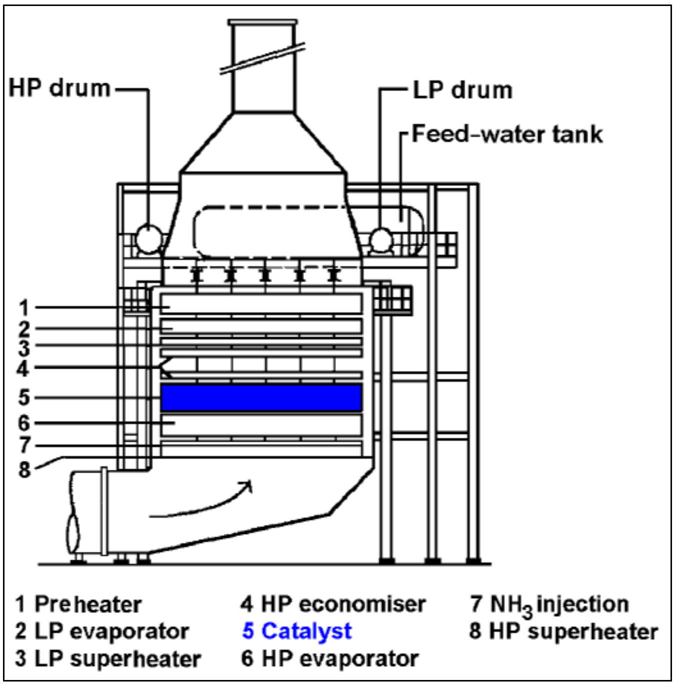


Figure 7.14: SCR installation with vertical flow
[161, Joisten, et al.,]

7.1.7.3.4 Comparison of 1993 and 1999 NO$_X$ control costs for gas turbines

NO$_X$ control technology	Turbine output (MW)	Emission reduction (ppm)	1993		1999	
			USD/tonne	USD cents/kWh	USD/tonne	USD cents/kWh
Water/steam injection	4 – 5	Uncontr. → 42	1750 – 2100	0.47 – 0.50	1500 – 1900	0.39 – 0.43
DLN	4 – 5	Uncontr. → 42	820 – 1050	0.16 – 0.19	n.a. [2]	n.a.
DLN	4 – 5	Uncontr. → 25	n.a.[2]	n.a.	270 – 300	0.006 – 0.09
Catalytic comb. [1]	4 – 5	Uncontr. → 3	n.a.	n.a.	1000	0.32
Low temp. SCR	4 – 5	42 → 9	n.a.	n.a.	5900	1.06
Conventional SCR	4 – 5	42 → 9	9500 – 10900	0.80 – 0.93	6300	0.47
High temp. SCR	4 – 5	42 → 9	9500 – 10900	0.80 – 0.93	7100	0.53
SCONO$_x$	4 – 5	25 → 2	n.a.	n.a.	16300	0.85
Water/steam injection	20 – 25	Uncontr. → 42	980 – 1100	0.24 – 0.27	980	0.24
DLN	20 – 25	Uncontr. → 25	530 – 1050	0.16 – 0.19	210	0.12
Catalytic comb. [1]	20 – 25	Uncontr. → 3	n.a.[2]	n.a.	690	0.22
Low temp. SCR	20 – 25	42 → 9	n.a.	n.a.	2200	0.43
Conventional SCR	20 – 25	42 → 9	3800 – 10400	0.30 – 0.31	3500	0.20
High temp. SCR	20 – 25	42 → 9	3800 – 10400	0.30 – 0.31	3800	0.22
SCONOX	20 – 25	25→ 2	n.a.	n.a.	11500 [3]	0.46
Water/steam injection	160	Uncontr. → 42	480	0.15	480 [4]	0.15
DLN	170	Uncontr. → 25	n.a.[2]	n.a.	124	0.05
DLN	170	Uncontr. → 9	n.a.	n.a.	120	0.055
Catalytic comb. [1]	170	Uncontr. → 3	n.a.	n.a.	371	0.15
Conventional SCR	170	42 → 9	3600	0.23	1940	0.12
High temp. SCR	170	42 → 9	3600	0.232	2400	0.13
SCONOX		25 → 2	n.a.	n.a.	6900 [2]	0.29

Notes:

(1) Costs are estimated, based on Catalytica's 'Xonon™' catalytic combustor technology which entered commercial service in 1999. Annualised cost estimates provided by the manufacturer are not based on 'demonstrated in practice' installations.

(2) 'n.a' means technology that was not available in 1993, or technology that is obsolete in 1999.

(3) The SCONOX ™ manufacturer provided a quote for a 83 MW unit. The quote has been scaled to the appropriate unit size.

(4) The one baseload gas turbine installed in 1990 is the only baseload turbine that is equipped with steam injection. All subsequent baseload machines have been equipped with DLN. For this reason, the 1993 figures are assumed to be unchanged for steam injection.

Table 7.2: Comparison of 1993 and 1999 NO$_X$ control costs for gas turbines (retrofitting costs are not considered)
[182, OSEC, 1999]

The costs listed in Table 7.2 are strongly dependent upon the specific boundary conditions of the gas turbine and a transfer to other plants may not be possible. The cost data are not applicable for offshore installations.

7.1.8 Control of NO_X emissions from spark-ignited (SG) and dual fuel (gas mode)

The most important parameter governing the rate of NO_X formation in internal combustion engines is the combustion temperature; the higher the temperature the higher the NO_X content of the exhaust gases. One method to reduce the combustion temperature is to lower the fuel/air ratio, the same specific heat quantity released by the combustion of the fuel is then used to heat up a larger mass of exhaust gases, resulting in a lower maximum combustion temperature. This primary measure called the lean-burn approach in reciprocating engines is analogous to dry low-NO_X combustors in gas turbines. Gas engine (SG and DF) installations have low NO_X levels due to the lean-burn approach. In some special applications (e.g. larger plants in non-attainment areas in the US), gas turbines are equipped with SCR for additional NO_X reduction.

Spark-ignited lean-burn (SG) and dual fuel (DF) engines in gas mode are often equipped with an oxidation catalyst mainly for CO removal. The NMVOC emission from spark-ignited lean-burn gas (SG) engines and dual fuel (DF) engines in gas mode depend on the natural gas composition. Depending on the legislation in force and the composition of the natural gas, NMVOC secondary emission reduction techniques might, in some cases, be needed and oxidation catalysts for simultaneous CO and NMVOC reduction are applied.

In the case of SCR, a urea solution is generally the reduction agent of choice for SCR systems applied to engines. For applications with varying loads, the engine emissions are measured at different load levels during commissioning. The measured emissions values are then entered into the system controls, which ensures that the reduction agent is injected into the exhaust gas stream in the correct quantities for varying NO_X levels. The catalyst type and the SCR reactor size are tailored to the pressure drop constraints of each particular application so that the engine performance is not affected by any changes [167, Rigby, et al., 2001].

7.1.9 Control of NO_X emissions from gas-fired boilers

The boilers and firing systems are in general designed for low NO_X firing. Basically there are three different ways to reduce NOx emissions:

- application of low NO_X burners. The conditions for low NO_X emissions is a low temperature in the primary combustion zone and a sufficient long retention time of the flue-gases in the furnace for a complete burnout. This will reduce the flame temperature
- Flue-gas recirculation is a method that can be effective if a large percentage of the emission is thermal NO_X. It reduces both the flame temperature and the concentration of oxygen as well
- two stage combustion reduces the reaction between oxygen and nitrogen in the air during the combustion process. Substantially low NO_X emissions can be achieved by supply of the air at three stages around the individual burner and supplementing air above the individual burners and a precise dosing of these air streams.

The NO_X emissions, which are standard for gas-fired boilers, are lower than 100 mg/Nm^3.

7.1.10 Water and waste water treatment

For the gas turbine and the HRSG, demineralised water is required for the following purposes:

- to compensate for the blowdown water from the drums for the HRSG. If steam or water injection is applied, the water loss also has to be compensated for by make-up water. The quality has to meet the requirements of the manufacturers and water treatment is, therefore, required. Demineralisation is usually sufficient to meet these requirements
- demineralised water is usually used for washing the gas turbine compressor. Condensate from the water/steam cycle is sometimes used for online washing, but usually demineralised water is supplied to a separate water wash unit. For offline washing, a detergent is added to the demineralised water to improve the washing effect.

Waste water from a gas turbine and an HRSG (if applied) includes:

- blowdown water from the boiler circulation system to maintain the quality of the boiler water. To protect the boiler from corrosion, the boiler water usually contains additives such as ammonia, sodium hydroxide and/or phosphates. In practice, this blowdown water is quenched and discharged to sewerage systems or to a water treatment plant if the water does not meet permit requirements
- waste water from the gas turbine water washing process can be discharged or may have to be considered as a chemical waste, depending on the detergents used for washing and the compressor materials to be disposed of
- water, which is contaminated with oil or with fluids containing oil, is usually collected into a collecting system and discharged separately to a treatment plant
- remaining waste water from the plant, such as scrubbing water, is normally discharged to the domestic sewerage system.

Further treatment of waste water from the gas turbine (and/or HRSG if applied) is necessary to meet the permit requirements for the discharging the waste water.

7.1.11 Control of noise emissions

The large equipment used in gas-fired power plants can give rise to emissions of noise, and/or noises due to vibrating machinery. In these cases, the noise emissions may be abated in the following way:

- by locating gas turbines, steam turbines and generators in enclosures
- by ventilating enclosures with low noise fans
- by adding cladding to the steam turbine support structure
- by fitting high level stack silencers
- by locating boiler feed pumps in enclosures
- by building a pump house around the pumps for circulating the cooling water
- by operating moderate noise fans in the cooling towers (it should be noted that the noise emissions from once-through cooling water systems are less than from cooling towers).

7.1.12 Offshore combustion installations

Oil and gas production facilities in the UK and Norwegian offshore sector, based on a steel or concrete support structure and topside modules containing oil and gas processing equipment, typically use gas turbines for power generation and possibly large pump and compressor drives, with reciprocating internal combustion engines ('diesels') for emergency generation and possibly for fire pump duty. Such combustion installations operated on offshore platforms in the North Sea, as covered by the IPPC Directive, i.e. of a rated thermal input exceeding 50 MW, namely gas turbines, operate a total number of about 270 turbines. These are turbines that are mostly fuelled by natural gas produced from the field under operation. Part of it is not suitable for further purposes and, therefore, has had to be flared or vented to theair. Therefore, it is not, or cannot be, fully processed and varies both in composition and calorific value, from field to field and, over time, even within a field [124, OGP, 2000].

Figure 7.15: North Sea oil platform
[150, Marathon OIL, 2000]

For technical reasons and for safety, 44 % of the turbines operated offshore are of the 'dual fuel' type and can be fuelled either by natural gas from the producing field or by diesel fuel. Dual fuel turbines are usually employed to generate the electrical power required for the activities performed onboard a platform. They are operated on diesel fuel under non-routine or emergency conditions, e.g. where the gas production has been shut down. Diesel is also used for start-up operations when only a limited amount of natural gas is available. The remaining 56 % of turbines operated offshore are of the single gaseous type and are primarily used for mechanical drives, such as gas compression [124, OGP, 2000]. There are two basic types of industrial gas turbines used on offshore applications, aeroderived gas turbines and the heavy-duty gas turbines. The dual fuel (DF) reciprocating engine is a new prime mover type used in the off shore market (see Section 7.1.3.2) for more information about this type of engine.

The aeroderivative type of gas turbine is more adaptable to variable loads than the heavy-duty unit and is, therefore, widely used for gas and oil pumping, as well as for electrical power generation. The turbine may contain more than one concentric shaft to obtain optimum performance from different stages of gas expansion and air compression.

The heavy duty gas turbines are used mainly for electrical generation. They are often built as a single shaft machine where the compressor, turbine and power turbine are all on a single shaft. On start-up, the complete rotor has to be accelerated to a self-sustaining speed, usually by a diesel engine or electric motor. When used for power generation, they can maintain good speed control, even in the event of a loss of electrical load [123, DTI, 2001].

The offshore oil and gas facility, although using some combustion equipment common to onshore applications, is a more complex and potentially hazardous environment than, say, an onshore power station, which results in higher cost due to the following resons:

- logistics related to bringing people and equipment to the installation
- limited cabin capacity for additional crew during modification work, which either may mean a prolonged installation period or the need for renting a flotel (floating hotel)
- higher man-hour rates
- hot work in congested process areas is a safety hazard; thus more of the work will have to be carried out in habitats (which add to the cost) or during complete shutdown (loss of production)
- the more extensive and sophisticated fire protection systems often have to be modified too in addition to the equipment modifications
- if modifications require additional space, expensive structural work has to be added, if at all possible
- the value of lost or deferred production is often more significant than for a landbased facility.

In addition, space and weight are at a premium, leading to a much higher equipment density than is common in onshore applications. In addition, any undue complexity is generally avoided offshore, because of the weight, space, and operability factors, including safety factors [123, DTI, 2001]. Therefore, more complex systems, such as combined cycle plants, are applied only in a very few cases, as are systems which require significant chemical usage or supporting equipment offshore, e.g. flue-gas cleaning devices.

7.1.12.1 Control of emissions to air from offshore gas turbines

Consideration of the mechanisms of nitric oxide formation (see also Section 1.3.2.2) shows that the design of combustion equipment to reduce its formation by the thermal route involve limiting the overall temperature and residence time and minimising the formation of hot spots by optimising air and fuel mixing.

Improving the thermal efficiency by operating at higher temperatures, however, tends to increase nitric oxide concentrations, although mass releases may be reduced because of increased energy efficiency, but this phenomenum is, however, very machine specific. In addition, NO_X emissions may increase at part load conditions, and this should be considered when design proposals are reviewed.

Water and steam injections are available for a range of gas turbines. This requires modifying the fuel jets or installing a separate water injection manifold. Water is injected at a pre-set ratio with the fuel. For example, a 50 MW_{th} input installation would require about three tonnes/hr of water to achieve a 65 % reduction in nitrogen oxides. There is a modest increase in power output but a slight decrease in the turbine efficiency. However, water must be of at least ‘high pressure boiler feed-water’ quality, and such quality and quantities are not usually readily available on an offshore facility.

Steam injection into the combustion chamber of a gas turbine has the same effect as water injection in cooling the combustor and reducing the thermal oxides of nitrogen. For a 50 MW_{th} input installation about four tonnes/hr of steam would be required to achieve a 65 % reduction in nitrogen oxides. The Cheng steam injection cycle for simultaneously reducing NO_X and increasing efficiency which can be applied to all gaseous fuel turbines with conventional combustion (diffusion flame technology) can be applied to offshore turbines as well. Conventional steam injection in gas fired turbines is described in Section 7.1.7.3.1 in this BREF, where 40 to 60 % NO_X emission reduction can be achieved with no significant increase in CO emission. However, the Cheng steam injection cycle provides solutions which makes this NO_X control technique more qualified than conventional steam injection. The Cheng system provides unique mixing of gaseous fuel and steam so that NO_X can be reduced by up to 95 %. Again, the high quality water required to produce steam is not usually readily available in an offshore facility [123, DTI, 2001].

Some turbine manufacturers are developing dry low NO_X emission (DLE) technology, using gas analyser equipment and software integrated in the fuel and engine management system, for new turbines and for retrofitting equipment. Because of the special constraints on offshore platforms (i.e. space, complexity and weight) that makes water and steam injection not a very practical solution, dry low NO_X technology is currently applied to a few gas turbines on Norwegian platforms. As reported by [122, Carstensen and Skorping, 2000], DLE turbines are installed more frequently on mechanical drive applications. This is because many turbines used in power generation have a dual fuel system. Turbines that combine lean premix features as well as liquid fuel capabilities do not yet have sufficient field experience and are, therefore, not applied to such turbines.

The NOxRED-GT can be applied to new and existing gas turbines, but the main market is on SAC turbines offshore. Since ammonia is injected in small amounts after the combustion chamber, the NOxRED-GT will not affect the burning condition and the turbine efficiency. The technique can be used on both dual fuel and single fuel turbines and is independent of the fuel quality.

Post-combustion techniques such as SCR, have been applied to gas turbines in several European countries and in parts of Japan and California, in order to meet low emission standards for nitrogen oxides. SCR is a chemical reduction of nitrogen oxides by a reducing agent, usually ammonia gas. According to the space and weight of such a system and particularly the health and safety problems encountered by the storage and handling of ammonia, this technique has not been applied and is not considered particularly viable for offshore combustion installations at the present time.

The Parametric Emission Monitoring System called PEMS can be seen as an alternative to continious monitoring CEMS offshore. PEMS is widely used in the US as NO_X monitoring techniques. In the US, the operator of an installation can apply for using PEMS instead of CEMS if the installation can document that the new PEMS has ‘the same or better precision, reliability, accessibility and timeliness as that provided by the continious emission monitoring systems’.

7.1.12.2 Efficiency of offshore gas turbines

Open or simple cycle configurations are mostly used for offshore facilities, because of space, weight, and operability reasons. Thermal efficiencies of up to about 40 % can be expected from the latest new large gas turbines. However, for existing gas turbines under operating conditions more typical numbers are 30 – 35 % of thermal efficiency. Higher thermal efficiencies can lead to high combustion temperatures, which may increase NO_X production, thus requiring sophisticated combustion chamber designs to achieve both high thermal efficiencies, and low emissions [123, DTI, 2001].

The efficiency of the turbines themselves is only one of the factors of the total energy efficiency of the offshore installation. To obtain a more efficient energy production on the platforms, many factors need to be taken into account and some of them are listed below:

- optimisation of the process in order to minimise the energy consumption and the mechanical requirements
- using variable speed drives for large rotating equipment if loads are variable
- optimising line sizes to reduce pressure drops, using expanders and hydraulic pumps to utilise pressure drops instead of throttling
- optimise equipment sizing to avoid recycling amd part-load operation
- optimise and maintain inlet and exhaust systems in a way that keep the pressure losses as low as practically possible
- utilisation of gas turbine exhaust heat for platform heating purposes.

7.2 Examples of applied processes and techniques

This part of Chapter 7 provides a number of examples of techniques and processes currently applied in different gas combustion installations. The aim of the examples is to demonstrate how specific techniques have been applied to new or retrofitted plants in order to ensure a high level of protection for the environment as a whole, taking into account, in each case, the particular site-specific conditions and environmental requirements. However, from the information collected, it is not always clear, if or how each technique described in the examples has been assessed against the definition of BAT given in article 2 (11) of the Directive, as well as against the list of ‘considerations to be taken into account generally or in specific cases when determining the best available techniques bearing in mind the likely costs and benefits of a measure and the principles of precaution and prevention’ and, consequently, how the technique has been selected and applied. Furthermore, it cannot be assured that the environmental performance presented is constant and continual under all operational conditions, over which time period, whether any problems have been encountered, and what the cross-media effects are. Also, it is not always clear what the driving force is for applying the technique and how the costs and environmental benefits are related in each case. Therefore, the information provided in the following examples is meant only to provide general indications of reported current practice and cannot be considered as appropriate reference points. The techniques that are given as examples arise from information provided and assessed by members of the Technical Working Group as part of the information exchange of LCPs.

7.2.1 Individual techniques to reduce emissions from gas-fired large combustion plants

EXAMPLE 7.2.1.1 WATER INJECTION AS A PRIMARY MEASURE TO REDUCE EMISSIONS OF NO_X FROM GAS TURBINES

Description: In the example plant, water injection was applied in a 25 MW_e gas turbine, but it can also be applied to much larger turbines. Water injection can generally be performed either by the injection of a mixture of fuel and water or by injecting water through nozzles directly into the combustion chamber.

Achieved environmental benefits: Reduced emissions of NO_X as shown in Table 7.3. With the injection of water, NO_X emissions were reduced from 400 mg/Nm^3 to about 60 mg/Nm^3.

	Measured emission values
CO (mg/Nm^3)	5 – 7
NO_X (mg/Nm^3)	48 – 57

Table 7.3: NO_X and CO emission by applying water injection to a gas turbine [44, Austrian Ministry of Environment, 2000]

Applicability: Water injection can be applied to new and existing gas turbines.

Cross-media effects: As water injection can increase the amount of CO in the turbine off-gas, a CO catalyst was installed to oxidise the CO to CO_2. Steam or water injected into gas turbines needs to be of very high purity, and therefore application of this technique requires the use of a high quality water treatment plant, which in turn may create a liquid effluent requiring disposal.

Operational data: The efficiency of the gas turbine is 36 %. The injection of water or steam to reduce NO_X can only be carried out to a certain limit. If the steam flowrate injected in the fuel burner is too high (typically the gas turbine supplier fixes a limit on steam flowrate/fuel gas flowrate = 1.2), the effects on the compressor are relevant.

Economics:

Driving force for implementation: Low NO_X emissions

Reference literature: [44, Austrian Ministry of Environment, 2000], [32, Rentz, et al., 1999], [182, OSEC, 1999].

EXAMPLE 7.2.1.2 GAS TURBINE EQUIPPED WITH A DRY LOW NO_X COMBUSTION CHAMBER

Description: The gas turbine is operated as part of a district heating plant in Austria. The gas turbine has a capacity of 40 MW_e and is equipped with a dry low NO_X combustion chamber to reduce the generation of NO_X. The basic characteristic of dry low NO_X combustors is that the air and fuel mixing and combustion both take place in two successive steps. By mixing combustion air and fuel before combustion, a homogeneous temperature distribution and a lower flame temperature can be achieved, this results in lower NO_X emissions.

Achieved environmental benefits: Low emission levels of NO_X and CO.

Applicability: Dry low NO_X technology is available for new gas turbines and can also be retrofitted to a large number of existing gas turbine types.

Cross-media effects: None.

Operational data: NO_X and CO are measured continuously. The measured data are transferred online to the competent authority.

	Measured emission as half hourly average, at 15 % O_2 (mg/Nm^3)	Remarks
NO_X	33	Dry low NO_X burner, continuous measurement
CO	35	Continuous measurement
Dust	<1	Determined by calculation
NH_3	<2	Discontinuous measurement

Table 7.4: Measured emission concentrations of a gas turbine with dry low NO_X combustion chamber

Economics: The cost of DLN combustors to be retrofitted can vary dramatically for the same size turbine offered by different manufacturers. As an example, the incremental cost of a DLN combustor for a new gas turbine from manufacturer A (5.2 MW) was approximately EUR 180000, whereas the incremental cost for a similar DLN combustor from manufacturer B (5.1 MW) was EUR 20000. The cost discrepancy is related to performance capabilities, design complexity and reliability/maintenance factors. Investment costs for retrofitting can be estimated as EUR 20 – 40/kW$_{e.}$

For new build plants, it can be assumed that dry low NO_X combustors are nowadays no more expensive than the former conventional combustors. Therefore, for new installations, the additional costs for using dry low NO_X combustors can be considered as negligible.

Driving force for implementation: Low emission levels of NO_X and CO.

Reference literature: [32, Rentz, et al., 1999], [44, Austrian Ministry of Environment, 2000], [182, OSEC, 1999].

EXAMPLE 7.2.1.3 SCR SYSTEMS APPLIED TO GAS TURBINES COMBINED WITH HEAT RECOVERY BOILERS

Description: The SCR process is a widely applied process for the reduction of nitrogen oxides in exhaust gases from large combustion installations (see Chapter 3 for detailed information). It is applied in a number of countries, such as the US and Japan and widely in Europe, particularly in Austria, France, Germany, and the Netherlands. In Italy, SCR has also been applied but only to one gas turbine not using a commercial fuel. Further applications are planned in Denmark. In the US (especially in California as described below), the use of SCR gas turbines is mostly in co-generation applications. Approximately 85 % of the estimated 300 equipped units have a capacity between 20 and 80 MW$_{th}$. Some units are in the 3 – 10 MW$_{th}$ capacity range [32, Rentz, et al., 1999].

As examples:

- in case A, a simple cycle gas turbine was specified in a permit issued in California, US, with a limit of 5 ppmvd NO_X (approx. 10 mg/Nm^3) at 15 % O_2 averaged over three hours with an ammonia slip limited to 20 ppmvd at 15 % O_2. The determination was made for a 42 MW gas turbine with water injection and SCR. This turbine has been in operation since 1995 [183, Calepa, 1999].

- in another case (case B), a combined cycle gas turbine (CCGT) permit was issued in California US with a limit of 2.5 ppmvd NO_X (approx. 5 mg/Nm^3) at 15 % O_2 averaged over one hour with ammonia slip limited to 10 ppmvd at 15 % O_2. This determination was for a gas turbine nominally rated at 170 MW with dry low NO_X combustors and SCR [183, Calepa, 1999].

- in the third case (case C), a combined cycle gas turbine was operating under the limit of 3 ppmvd NO_X (approx. 6 mg/Nm^3) at 15 % O_2 averaged over three hours with the ammonia slip limited to 10 ppmvd at 15 % O_2. This emission level was achieved on a 102 MW combined cycle gas turbine also in California US. The gas turbine is equipped with dry low NO_X combustors and an SCR. This unit has been operating since October 1997 [183, Calepa, 1999].

There are other major combined cycle and co-generation power plant projects currently going through the California Energy Commission's (CEC) siting process with a limit of 2.5 ppmvd NO_X (approx. 5 mg/Nm^3) at 15 % O_2 averaged over one hour.

Achieved environmental benefits:

Parameters	Value	Comments
NO_X concentration in clean flue-gas	5 – 42 mg/Nm^3	Reference O_2 content 15 %
NO_X reduction	60 – 85 (95) %	
NH_3/NO_X molar ratio	0.9 - 1.6	

Table 7.5: NO_X emissions measured by using an SCR system at a gas turbine

Applicability: SCR systems can be applied to new plants but it can also be retrofitted to existing ones if it has already been taken into account at the design stage. The lifetime of an SCR system typically exceeds 5 – 8 years without any regeneration or replacement.

Cross-media effects: Ammonia is used as an additive. It use may result in a certain amount of ammonia emitted to the air.

Operational data:

Parameters	Value	Comments
Operating temperature (°C)	170 – 510	Catalyst based on metal oxides (V, Ti), on Ti, silica or W
	315 – 510	Zeolites catalyst (based on precious metal bases)
Pressure drop across the catalyst (10^5 Pa)	0.0047 – 0.015	

Table 7.6: Operational data using an SCR system at a gas turbine

Economics:

Cost	Percentage share of total investments
Installation: • reactor housing • ammonia supply (storage, vaporisation and injection systems • flue-gas ducting • monitoring and control equipment • electro technical installations • insulation. painting, etc.	30 %
Construction and start-up	30 %
Planning, licensing, unforeseen	10 %
First catalyst filling	30 %
Total investment for the SCR unit	100 %

Table 7.7: Cost components for SCR at gas turbines

Type of catalyst	SCR		SCR after DLN retrofit
	New	Retrofit	
Catalyst volume requirements (m^3/MW_e)			
High temperature	3 – 4	4 – 5	3
Low temperature	1.5 – 2	2 – 2.5	1.5
Catalyst price (EUR/m^3)			
High temperature	12000	12000	12000
Low temperature	24000	24000	24000

Table 7.8: Cost figures for SCR at gas turbines

Related operating costs include the costs incurred by ammonia consumption, steam consumption, electricity consumption, catalyst replacement, maintenance and repair, insurance and taxes, and possibly personnel, administration and catalyst disposal costs.

Advances in SCR technology in the past few years have resulted in a 20 per cent reduction in the amount of catalyst required to achieve a given NO_X target level. In addition, increasing experience gained in the design and installation of SCR units has lowered engineering costs. These two factors have substantially reduced the cost of SCR. Operating costs have also been reduced through innovations, such as using hot flue-gas to preheat ammonia injection air which lowers the power requirements of the ammonia injection system [183, Calepa, 1999], [182, OSEC, 1999].

Driving force for implementation: Reduction of NO_X emissions.

Reference literature: [32, Rentz, et al., 1999], [57, Austrian Ministry of Environment, 2000], [183, Calepa, 1999].

EXAMPLE 7.2.1.4 SCR SYSTEMS APPLIED TO GAS-FIRED ENGINE PLANTS

Description: The SCR process is a widely applied process for the reduction of nitrogen oxides in exhaust gases from large combustion installations. SCR has also been applied to gas fired engine plants mainly in the US.

Achieved environmental benefits: Low NO_X emissions.

Operational data: Table 7.9 below lists the main performance parameters of the gas fired engine plants:

	Plant A	**Plant B**
Location	US	US
Commissioning year	2002	2001
Plant type	Power generation	Power generation
Fuels	Natural gas	Natural gas
Combustion technique	20 gas engines	5 gas engines
Capacity	111 MW	14 MW
Secondary measure	SCR (Reagent: aqueous urea)	SCR (Reagent: aqueous urea)
NO_X without SCR (mg/Nm^3)	159	187
NO_X with SCR fresh catalyst (mg/Nm^3) at 15 vol-% O_2	5 – 19	13
NO_X reduction rate over SCR	88 – 97 %	93 %
Ammonia slip (NH_3) (mg/Nm^3) at 15 vol-% O_2	2 – 6	<2

Table 7.9: Emission levels of two gas-fired engine power plants equipped with SCR

Applicability: SCR systems can be applied to new plants but it can also be retrofitted to existing ones.

Cross-media effects: Urea is used as an additive, but it may result in a certain amount of ammonia emitted to the air. The catalyst needs to be regenerated.

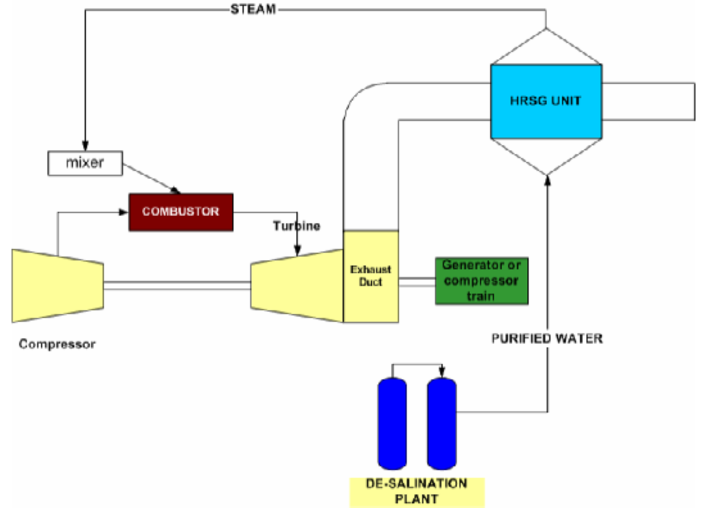
Driving force for implementation: Reduction of NO_X emissions. However, SCR has been considered mainly where local air quality sandards requested a high reduction of NO_X or ozone emissions, as a result of operation in highly populated areas or the contribution of several industries or mobile sources.

Reference literature: [78, Finkeldei, 2000], [184, Krishnan, 2002].

EXAMPLE 7.2.1.5 THE CHENG INJECTION CYCLE FOR SIMULTANEOUS NO_X REDUCTION AND EFFICIENCY INCREASE

Description: The Cheng steam injection cycle provides solutions which make this NO_X control technique more suitable than a conventional steam injection. The Cheng steam injection cycle technique provides unique mixing of gaseous fuel and steam so that NO_X can be reduced by up to 95 % with no significant increase in CO emission.

The thermal efficiency of the process is reduced if the steam is produced in a separate boiler. However, the power output from the turbine increases up to 60 %, with 50 % being the average. When using a heat recovery steam generator (HRSG) for steam production, the thermal efficiency increases. Steam for three turbines is produced by one HRSG installed on the exhaust duct from one gas turbine. This makes installation less expensive and time consuming. The Cheng steam injection cycle requires the same purity of water as a conventional steam injection.



Equipment/modifications required:

- water production plant
- HRSG
- steam piping
- gas turbine Modifications
- modifications to the turbine logical control system.

Figure 7.16: Principle sketch of Cheng Steam Injection Cycle

Since the steam will achieve the same pressure and temperature as the flue-gas in the combustion chamber, the increase in power output with will be greater than with a combined cycle.

Achieved Environmental Benefits:

- NO_X reduction (up to 95 %)
- no penalty in terms of increased CO associated with steam injection
- higher steam/fuel ratio possible than other steam injection technologies
- increase in thermal efficiency, up to 45 %, which reduces CO_2 emissions per kWh produced.

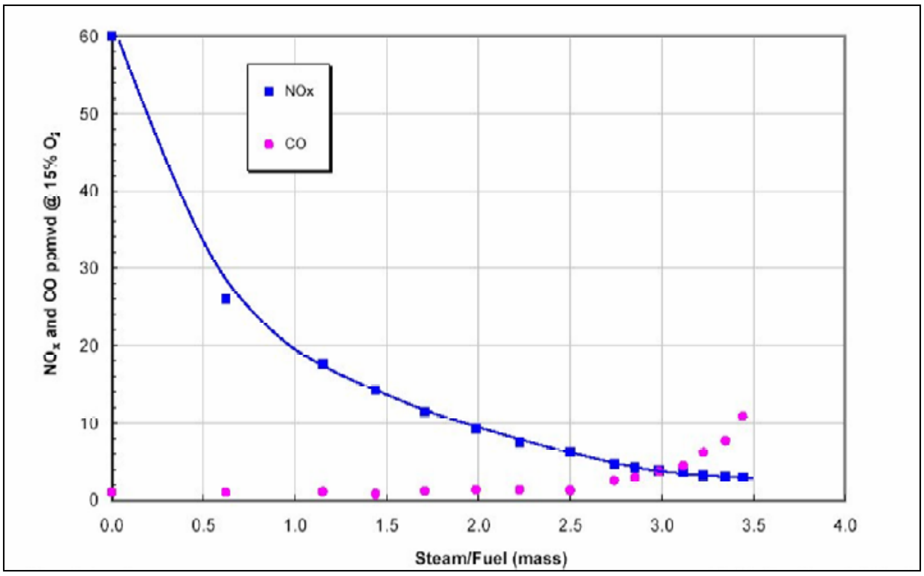


Figure 7.17: NO_X and CO emission as a function of steam ratio

Steam/fuel ratio	Achieved NO_X level (ppm)	Thermal efficiency
0	Standard configuration	34.5
1.5	25	39
3	7	44

Table 7.10: Achieved NO_X emission and thermal efficiency for conventional combustor turbines with modified fuel nozzle

Applicability: The Cheng Steam Injection Cycle is utilised at about a hundred installations in Japan, the US and Europe. The technology can, in general, be applied on all gaseous fuel fired turbines with conventional combustion (diffusion flame technology).

Necessary modifications and installations are listed below:

- replace fuel injection nozzles
- modification of GT control system
- reducing one exhaust channel and installation of boiler (HRSG)
- piping for steam from HRSG to GT generator/compressor sets
- water to be produced by either reverse osmosis or acuum distillation.

Cross-media effects: Contrary to other steam injection concepts, the Cheng Cycle also features a unique control system that allows the power plant peak (maximum) thermal efficiency to follow load changes. This should be very applicable to offshore installations where the turbine load is not constant.

Operational data: The Cheng Steam Injection Cycle can be used at all operational loads. When needed, the steam injection can simply be turned off during operation. Only higher NO_X emission rates and larger fuel consumption in order to maintain delivered power will be the effect of the turn-off action.

Economics: Calculation example:

- installed Power: 3x 22 MW each, 66 MW total.
- one HRSG installed in the exhaust duct of one gas turbine, produces steam for three turbines
- steam/Fuel ratio of 2.5
- reduction of NO_X to <10 ppm
- additional costs for support structure for the installation on an offshore platform needs to be taken into account.

	Cost (NOK million)	Weight (t)
Gas turbine rebuild	30	~1
HRSG	10	30
De-salination plant for water production	6	16

Table 7.11: Costs and weight for a Cheng steam injection cycle on a GE LM 2500 package

Driving force for implementation:

- retrofit to Cheng cycle possible for all gas turbines with conventional combustion technology (diffusion flame combustor)
- little space required on gas turbine package for modification. Therefore, emission levels lower than DLE/DLN can be achieved in offshore installations that are not prepared for DLE/DLN turbines
- retrofit and maintenance cost lower than DLE/DLN systems available
- a conventional combustion system with Cheng steam injection has a higher availability then DLE/DLN systems. Hence more applicable on gas compression trains
- emissions lower than DLE/DLN systems without CO/UHC trade-off
- many offshore installations already have a HRSG onboard, which makes the requirement for modifications, investments and installation costs lower
- increased power output or reduced fuel consumption

Reference Literature: [196, ASME,], [197, ASME,], [198, ASME,], [199, Cheng, 1997]

EXAMPLE 7.2.1.6 CATALYST POLLUTION CONTROL TECHNOLOGY FOR THE REDUCTION OF CO AND NO$_X$ FROM COMBINED CYCLE GAS TURBINES

Description: The example technology uses a single catalyst that operates in two cycles: oxidation/absorption and regeneration. The catalyst works by simultaneously oxidising CO to CO_2, NO to NO_2, and then absorbing NO_2 onto its surface through the use of a potassium carbonate absorber coating. The regeneration of the catalyst is accomplished by passing a controlled mixture of regeneration gases across the surface of the catalyst in the absence of oxygen. The regeneration gases are steam, hydrogen and carbon dioxide. It uses no ammonia, and can operate effectively at temperatures ranging from 150 to 370 °C.

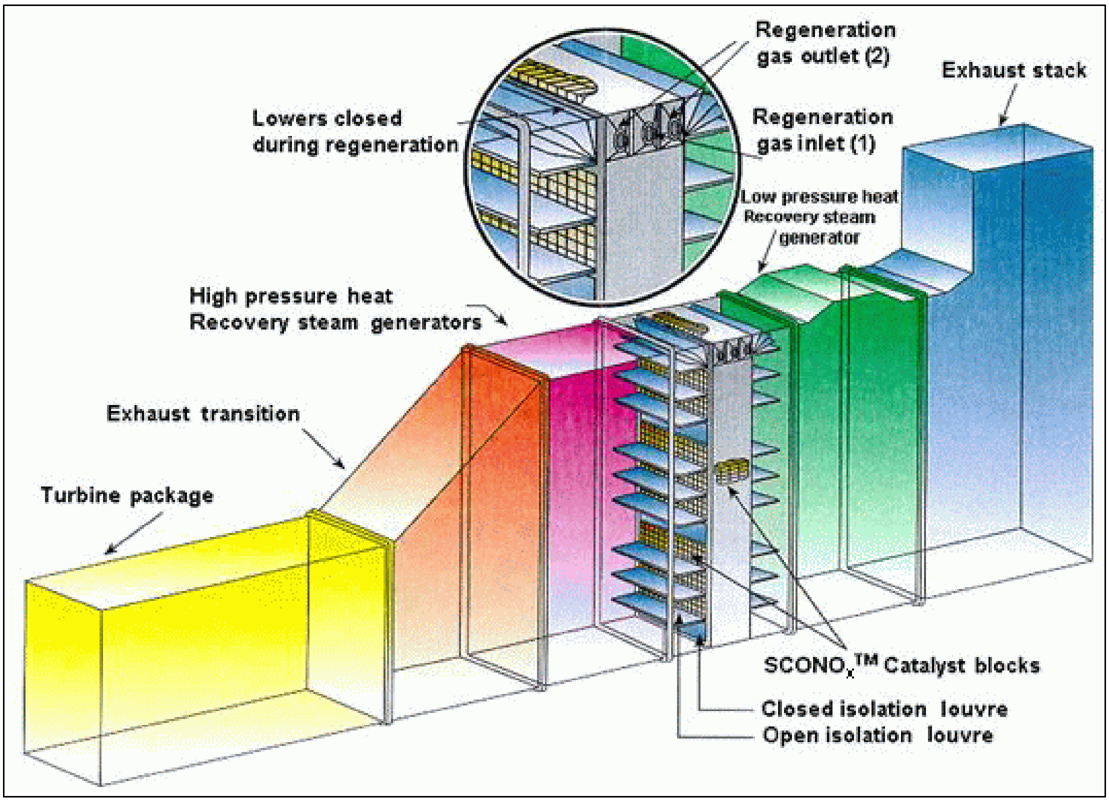


Figure 7.18: Schematic representation of the catalyst system
[26, ABB, 2000]

Achieved environmental benefits: By using this technology, combined cycle gas turbines can be operated with very low NO_X emissions levels. At the same time, the system reduces emissions of CO and non-methane volatile organic compounds. In conjunction with a sulphur removal catalyst, this system can also be used for reducing sulphur compounds from the exhaust gas.

Applicability: Applicable to both new and retrofit applications. Such a unit can be installed at the back-end of the boiler or in the 'heat recovery steam generator' within the envelope reserved for an SCR system.

Cross-media effects: The system emits CO_2, H_2O, N_2 and trace levels of SO_2 to the stack. Due to masking and poisoning of the catalyst, it requires annual catalyst cleaning with deionised water and a potassium carbonate solution (K_2CO_3). The spent cleaning fluids can be neutralised and disposed of through the sewerage system and are harmless to the water and soil.

Operational data:

- NO_X emissions below 2 ppm (4 mg/Nm^3 as NO_2 at standard conditions: 0 ºC, 1013 mbar)
- conversion rate of CO into CO_2 is 90 %
- the destruction of non-methane volatile organic compounds (NMVOC) is greater than 90 % at 315 °C
- the destruction of formaldehyde and acetaldehyde have been measured at 97 % and 94 % respectively at 150 °C.

Economics: The estimated cost numbers presented refer to a typical 400 MW size gas-fired power plant. The cost estimate numbers below are based on 8000 hours of operation per year and a NO_X reduction from 25 to 5 ppm (50 to 10 mg/Nm^3 as NO_2 at standard conditions 0 ºC; 1013 mbar), which equals approx. 666 tonnes (metric) annually of NO_X removed. Included in the costings are investment cost, operating and maintenance costs and indirect annual costs.

Investment costs: EUR 19.2 million.

This includes:
- plant equipment
- delivery
- fitting
- commissioning/start up.

This is the total cost from the supplier.

Operating and Maintenance costs: EUR 1.6million.

This includes:
- general maintenance
- steam and natural gas consumption in the regeneration cycle
- pressure drop across the unit (converted to power consumption)
- average cost/year for catalyst replacement (lifetime of the catalyst is seven years)
- catalyst disposal/refund.

Additional indirect annual costs to the contractor are not included.

A reduction of NO_X from 25 to 2 ppm (50 to 4 mg/Nm^3 as NO_2 at standard conditions 0 ºC; 1013 mbar) will contribute to an increase in the investment costs due to the need for an additional catalyst. It will also somewhat increase the operating and maintenance cost due to the increased consumption of natural gas and steam, and due to the increased pressure drop.

Driving force for implementation: Requirements to meet very low NO_X emissions and limitations set on using air pollution control equipment utilising ammonia, especially for plants situated in densely populated areas.

Reference literature: [26, ABB, 2000].

7.2.2 Improving the environmental performance of existing gas-fired large combustion plants

EXAMPLE 7.2.2.1 COMBINED CYCLE HEAT AND POWER PLANT WITH RETROFITTED COMBUSTION CHAMBERS

Description: The example plant was commissioned in 1994 and consists of two gas turbines (2 x 67.8 MW_e) with two dedicated waste-heat boilers (2 x 26.5 MW_{th}), including auxiliary firing and one steam turbine (48.8 MW_e). The standard fuel is natural gas. Light fuel oil is used as backup fuel. The combustion chambers of the gas turbines were retrofitted in 1997 in order to reduce the emission of NO_X. NO_X reduction at the fuel oil operation is realised by the injection of demineralised water.

Achieved environmental benefits: Comparatively low emission levels are achieved due to the low NO_X technique, taking into account the size of the plant. The measures to use waste heat lead to a high overall energy efficiency and thus minimise the consumption of resources and the subsequent emission of CO_2.

Applicability: Existing boilers in an old plant might be transformed into a waste-heat boiler. In general, retrofitting measures of this kind can be applied to existing plants.

Cross-media effects: The primary measures to reduce emissions do not produce any residues. The treatment of input water produces sludge.

Operational data: In 1999, a total of 530 GWh_e of electricity and 585 GWh of district heat were produced. The plant was in operation for 4456 hours. The annual mean value for the electrical net efficiency amounted to 39.5 % and 83.1 % for the overall energy efficiency (net). The volume flowrate of the exhaust gas added up to 2 x 526000 m^3/h at an O_2 content of 14.5 %. Table 7.12 shows the atmospheric emissions in 1999.

	Monitoring	Monthly mean value[1] (at 15 % O_2)	Specific emissions (kg/TJ fuel)
NO_X (mg/Nm^3)	Continuous	60	46.7
CO (mg/Nm^3)	Continuous	6	3.6
[1] Equivalent to annual mean value for rated load.			

Table 7.12: Emissions to air measured in 1999

In 1999, 132 million Nm^3 of natural gas (equivalent to 43.9 MJ/kWh_e) and 181 m^3 of light fuel oil were fired.

The waste water flow of the plant originates from the treatment of the feed-water and the condensate and from the treatment of the water for the district heating circuit. (8575 m^3/yr). The main source is the regeneration of the ion exchangers. Waste water from this process is discharged after neutralisation. AOX is the only substance which is monitored regularly. The mean concentration is 0.097 mg/l. Some 2.9 tonnes of oil and oil contaminated materials were recycled and 1.6 tonnes of filter material were disposed of.

As the adjacent residential site is only 110 to 300 metres away from the single components of the plant, extensive sound reduction measures had to be realised. These comprise acoustic insulations of the boilers and the ducts, sound absorbers and the encapsulation of noisy components.

Driving force for implementation: The heat and power station is part of a municipal energy concept which aims to provide economically priced district heat in the long run. Therefore, the production of heat should be coupled to the production of electricity as far as possible. The upper power limit for the plant is determined by the heat demand and the possibilities to market the electricity.

Reference literature: [98, DFIU, 2001].

7.2.3 Environmental performance of new gas-fired combustion plants

EXAMPLE 7.2.3.1 COMBINED CYCLE HEAT AND POWER PLANT WITH AUXILIARY BURNERS AND GAS AND FUEL OIL FIRING

Description: A combined cycle heat and power station commissioned in 1995 in Germany has a total rated thermal input of 640 MW_{th}. It consists of three gas turbines with three assigned waste-heat boilers including auxiliary firing, one boiler and two steam turbines. The boiler serves to provide for peak load operation and for increased safety of supply. The operation of the whole plant is optimised to cover the heat demand. Each of the gas turbines has a rated thermal input of 135 MW_{th} and a terminal rating of 35.5 MW_e. Each of the auxiliary firings of the waste-heat boilers has a rated thermal input of 49 MW_{th}. The steam is fed to the turbines and used for the production of district heat in condensers and other heat-exchangers, i.e. the so-called peak load preheaters. Steam is also fed into a net for process steam. The electrical efficiency in 1998 was 40.2 % and the overall efficiency 59.7 %.

Primary measures for NO_X emission control**:** An additional system for the injection of steam was installed for the reduction of NO_X. The control system injects steam into the combustion chamber with flowrates proportional to the consumption of natural gas. This increases the power and efficiency of the turbine. Furthermore, NO_X emissions are reduced by 30 %.

Further measures: Electrostatic precipitators are installed for the removal of oil vapour which occurs during the suction of the lubricating oil tanks (separation efficiency = 92 %).

Achieved environmental benefits: Lower emission levels of NO_X, SO_2 and dust.

Applicability: The plant was retrofitted from an old lignite and heavy fuel oil-fired CHP plant. One boiler of the old plant was included in the design of the new plant and was retrofitted to be fired either with natural gas or with light fuel oil.

Cross-media effects: Not known.

Operational data: The plant was in operation for 6538 hours, equivalent to 4885 full load hours. The emission limit values of the complete plant depend on the ratio between the power input of the auxiliary firing and the power input of the gas turbine. As the emission limit values for the single units also differ in the related O_2 contents, the assigned O_2 content for dual operation must also be calculated by weighting with the share of the power input. The following tables define three operational states and the measured emissions.

Operational mode	Rated thermal input of gas turbine (MW)	Rated thermal input of auxiliary firing (MW)	Exhaust gas volume flowrate (Nm^3/h)	Related O_2 content (%)
I	123	35.6	375000	13.3
II	119	8.5	360000	14.5
III	122	0	375000	15.0

Table 7.13: Operation modes of gas turbine and auxiliary firing

Pollutant	Operation mode	Monitoring	Daily mean value (mg/Nm^3)	Specific emissions (kg/TJ Input)
NO_X	I	Continuous	73	56.16
NO_X	II	Continuous	73	53.91
NO_X	III	Continuous	82	63.13
CO	I	Continuous	60	46.12
CO	II	Continuous	27	19.88
CO	III	Continuous	9	6.97

Table 7.14: Measured atmospheric emissions in 1998

In 1998, 102.63 million Nm^3 of natural gas and 123 tonnes of fuel oil were fired. The consumption of important auxiliary supplies is shown in Table 7.15.

Auxiliary material	**Oils**	**HCl (33 %)**	**NaOH (50 %)**	**$Ca(OH)_2$**	**$FeCl_3$**
Application	Turbines/ hydraulic systems	Input water treatment/conditioning/ waste water treatment			
Consumption (tonnes)	1.4	169	77	23	7.4
Specific consumption (g/MWh_e)	3.4	410.5	187	55.9	18

Table 7.15: Consumption of important auxiliary supplies in 1999

A system for full water softening is applied to the water for the boiler. If surface water is used it is also decarbonised. The plant is operated with separated sewerage systems. One of them for household like sewage, and a second for rainwater and water from the boiler, the cooling system, oil separators and settling tanks. This waste water is dumped to the receiving watercourse. In 1998, 251180 m^3 cooling water and 45182 m^3 waste water from the production process were discharged.

Economics: The total investment for the plant amounted to EUR 118 million in 1998. The total operational costs in 1998 were EUR 56.1 million.

Driving force for implementation: The imposition of more stringent emission limit values meant that the retrofitting of an existing lignite and heavy fuel oil fired heat and power station would have been necessary. At the same time, the plant life needed to be extended and the economical performance needed to be improved. For these reasons, the combined cycle power plant was erected.

Reference literature: [98, DFIU, 2001].

EXAMPLE 7.2.3.2 GAS-FIRED COMBINED CYCLE HEAT AND POWER PLANT WITHOUT AUXILIARY FIRING

Description: The example power plant was erected in Germany between 1994 and 1996 with a total capacity of 380 MW_e for power and 340 MW_{th} for district heat production (at the design stage). It consists of two gas turbines (i.e. GT1 and GT2), two waste-heat boilers and three condensers for the off-take of district heat. Each gas turbine is equipped with a 21-storied compressor and 72 burners in an annular ring combustion chamber, and has a maximum power output of 185 MW_e. The standard fuel is natural gas. Light fuel oil is used as back-up fuel. The waste heat boilers (dual pressure drum boilers) produce steam at high and low pressure (77 bar/525 °C and 5.3 bar/203°C). The steam turbine (back pressure turbine) is operated with sliding pressure and generates up to 108 MW_e.

Measures for optimised efficiency: To reach high efficiencies, the gas turbines work with a compression ratio of 15:1. The turbine gas temperature reaches 1100 °C. The whole plant reaches a gross electrical efficiency of 47.4 % (at the design point). As the operation of the plant is optimised to cover the heat demand, it is often operated at part load. The design with two turbines offers high flexibility in these cases. With two turbines in operation, high efficiencies can be achieved for loads of between 60 and 100 %. With a single gas turbine these efficiencies are achieved for loads between 30 and 50 %. At the minimum load, the efficiency of the gas turbine decreases by 8 % compared to full load operation. The use of heat is optimised by:

- controlling the use of the exhaust gas heat
- preheating the gas turbine combustion air at part load
- using the waste heat from the transformer.

These measures allow an overall energy efficiency of nearly 90 % to be achieved. The efficiencies of the whole plant are summarised in Table 7.16.

	Gross efficiency related to	
	Design point	Annual mean value 1999
Electrical efficiency for CHP production	47.4 %	44.8 %
Electrical efficiency for power production only	52.6 %	49.6 %
Overall energy efficiency	89.2 %	85.9 %

Table 7.16: Efficiencies of a combined-cycle power plant without auxiliary firing

Primary measures for NO_X emission control: The annular ring-type combustion chamber of the gas turbines is equipped with 72 low NO_X burners. NO_X reduction at the fuel oil operation can be achieved by the injection of demineralised water. The combustion air can be preheated to reduce emissions either in the case of part load operation or to reduce the risk of icing. These measures allow for NO_X emissions of <100 mg/Nm^3 for natural gas and <150 mg/Nm^3 for fuel oil.

Measures for reduced emission of sound: As the residential area is only 16 m away from the building's wall, very low emission limit values must be attained. At the residential area, a sound pressure level of 45 dB(A) originating from the power plant can be met by utilising the following single measures:

- adequate facade and roof
- overhead noise barrier and sound insulation of the inlet port for the combustion air
- soundproof pipes
- canals for combustion air and exhaust gas are equipped with acoustic absorbers
- stack with double walls
- 'silent' design of safety valves and *exhaust ventilator cowl.*

Achieved environmental benefits: The low NO_X technique is responsible for achieving comparatively low emissions, taking into account the size of the plant. Measures to use waste heat also lead to higher overall energy efficiency and thus minimise the consumption of resources and the emissions of CO_2.

Applicability: The plant was designed to cover a high heat demand. This is the main prerequisite for a reasonable operation of plants of the same configuration. On the other hand, the single components of the plant, offering low emissions on their own, can also be integrated into power plants of a different design.

Cross-media effects: The primary measures to reduce emissions do not produce any residues. The cooling water and the waste water resulting from the operation of the plant are treated on site. Thereby screenings and sludges are produced.

Operational data: In 1999, a total of 1182.2 GWh$_e$ and 1083.5 GWh of district heating were produced. The 3070 equivalent full load hours resulted from the demand for district heat. The volume flowrate of the exhaust gas was 1450000 m^3/h for a rated thermal input of 470 MW. Table 7.17 shows the emissions to the air in 1999.

	Monitoring	Daily mean values at 15 % O_2		Specific emissions (kg/TJ Input)	
Natural gas – firing		GT 1	GT 2	GT 1	GT 2
NO_X (mg/Nm^3)	Continuous	76.0	65.7	62.65	55.31
CO (mg/Nm^3)	Continuous	6.7	11.3	5.58	9.48
Fuel oil – firing		GT 1	GT 2	GT 1	GT 2
NO_X (mg/Nm^3)	Continuous	79.6	131.4	101.88	112.29
CO (mg/Nm^3)	Continuous	19.1	13.6	24.44	11.46

Table 7.17: Measured emissions to air in 1999

In 1999, 249.616 million Nm^3 of natural gas and 9463 m^3 of light fuel oil were fired. The consumption of important auxiliary supplies is shown in Table 7.18.

Auxiliary material	Oils	HCl (33 %)	NaOH (50 %)	NaCl brine	NH_4OH
Application	Turbines/ hydraulic systems	Waste water treatment/feed-water treatment			
Consumption	1735 litres	72 t	40 t	58 t	300 litres
Specific consumption (g/MWh$_e$)	1.5	61	34	49	0.25

Table 7.18: Consumption of important auxiliary supplies in 1999

One waste water flow originates from the treatment of the feed-water and the condensate (12000 m^3/yr). After sedimentation this water is fed into the municipal sewerage system. Further waste water results from elutriation of the boiler, depletion of the whole system and from condensates (11014 m^3/yr). This waste water is fed directly to the municipal sewerage system after cooling. Waste water from the regeneration of the ion exchangers is regularly controlled for the concentration of absorbable organic halogen (AOX). The mean value of the AOX concentration during the last five years was 0.053 mg/l.

Economics: The total investment for the new plant and the removal of the old coal-fired power station mounted up EUR 327 million in 1997. Detailed cost information is not available.

Driving force for implementation: The former heat and power station on this site could not reach the lower emission limit values in 1996. It also could no longer be operated in an economically reasonable way. The new plant offered higher efficiencies and a reduced manpower was needed for operation. The site already offered the complete infrastructure for supply and disposal. The old plant was completely demolished and the new one was built, as retrofitting the old plant could not achieve the efficiency of a new one.

Reference literature: [98, DFIU, 2001].

EXAMPLE 7.2.3.3 NATURAL GAS-FIRED COMBINED CYCLE HEAT AND POWER PLANT WITHOUT AUXILIARY FIRING FOR A RAILWAY SUPPLY SYSTEM

Description: The example power plant produces electricity with a frequency of 16.67 Hz for the power supply system of the German railway. It consists of two gas turbines (GTs) (both are 180 MW_{th}, or both are 60 MW_e,), two waste heat boilers and one steam turbine (57 MW_e). In this plant, the combination of gas turbines with 16.67 Hz generators was used for the first time. The temperature of the hot gas at the turbine intake is 1280 °C. At the outlet of the gas turbine the gas has a temperature of 540 °C at 1.053 bar and produces steam with a maximum temperature of 530 °C and 62 bar in the waste heat boiler. After the waste heat boiler, the flue-gas passes through an economiser and is finally conducted to the stack with a temperature of 110 °C. An additional stack is installed for each gas turbine for single operation without the steam cycle. The steam is conducted to the single pass steam turbine where it is expanded. The pressure in the condenser drops to 0.07 bar. The waste heat boilers have a second stage where low pressure steam is produced at 198 °C at 4.5 bar. This steam is also conducted to the steam turbine. The reverse-flow cooling system consists of four fan driven cellular radiators and the cooling water pump.

The plant was commissioned in 1994 (GT – unit 1) and in 1995 (GT – unit 2). The electrical net efficiency of the plant amounts to 49.6 % at full load and decreases to 42 % at 50 % load. For further decreasing load numbers, one of the gas turbines is turned off which results in a sudden increase of the efficiency to 48 %. For a 25 % load, the efficiency finally decreases to 40 %. The start-up time of a gas turbine amounts to 26 minutes for full load. 14 minutes after the start of the first gas turbine, the second one can be started. After 40 minutes, 120 MW_e are available for single operation of the gas turbines. The start-up of the waste heat boilers needs between three and six hours. For combined cycle operation, the maximum load changing speed is 20 MW/min.

Achieved environmental benefits: The construction of the hybrid burner (diffusion and premixing stage) in combination with an adapted burning chamber ensures low NO_X concentrations. The high electrical net efficiency of nearly 50 % allows for an efficient use of resources.

Applicability: The overall design of the plant was optimised for the production of electricity for the railway power supply system. Nevertheless, single components can also be integrated into other power plants to optimise emissions.

Cross-media effects: The cooling tower make-up water is treated in a slow decarbonisation plant. A sludge is produced which mainly contains lime. Furthermore, waste waters and small amounts of residues are produced.

Operational data: In 1999, 501 GWh_e of net electricity was produced. The number of equivalent full load hours amounted to 2830. Table 7.19 shows the atmospheric emissions of the gas turbines in 1999. The flue-gas flowrate is 2 x 500000 m^3/h at full load.

Pollutant	Measurement	Measured emission levels (mg/Nm^3)	Specific emissions (kg/TJ Input)
Dust			
NO_X	Continuous	41.6	32
CO	Continuous	1.8	1.4

Table 7.19: Measured emission levels in 1999

In 1999, 101.8 million Nm^3 of natural gas (= 0.2 Nm^3/kWh_e) were fired. Consumptions of the most important auxiliary supplies are shown in Table 7.20.

Auxiliary material	Lubricants	Ferrous-III-chloride-sulphate	Hydrated calcium lime	Ammonia water	HCl	NaOH
Application		**Water treatment**				
Consumption (t/yr)	0.5	60	70	0.5	20	13
Specific consumption (g/MWh$_e$)	1	120	140	1	40	26

Table 7.20: Consumption of important auxiliary supplies in 1999

The waste water flowrate of the whole plant is up to 75 m^3/h at full load. Some 60 m^3/h originate from the cooling system. This waste water is dumped to the pre-clarifier without treatment. The waste waters from the full water softening plant (15 m^3/h) are neutralised and dumped to the pre-clarifier together with the effluent of the cooling system. The concentrations of impurities in this mixed waste water is shown in Table 7.21 for 1999. These results show the initial level of pollution before the water enters the power plant.

	Mean value from 14 measurements (if not specified) (mg/l)	Specific emissions (g/MWh$_e$)
Cl	339	137
AOX	0.06	0.024
COD	67	27.1
P	17.5	7.07
N	8	3.23
Zn	<50*	-
Cr	<2*	-
Cd	<0.1*	-
Cu	<5*	-
Pb	<3*	-
Ni	<5*	-
Filterable matter	8.7	3.52
Sulphate	624	252.2
Hg	<0.1*	-
pH-value	8.3	-
*These values result from a singular measurement and thus cannot be transformed to specific loads		

Table 7.21: Concentrations of impurities in the waste water of the power plant

The sole source of a considerable amount of the residues is the cooling tower make-up water treatment, where sludge is produced. In 1999, 214.4 tonnes of this sludge had to be disposed of in a landfill and 50.3 tonnes were used for spreading in agriculture. Furthermore, 10 tonnes of used detergent from turbine cleansing and six tonnes of residues from the oil separator, were produced.

The legal requirements for sound control are adapted to the residential site which is about 500 m away from the plant. With the help of noise attenuators, a sound immission level of 30 dB(A) can be reachedfrom this distance.

Economics: The total investment amounted to EUR 185 million (1995). This equals a specific investment of EUR 1043/kW$_e$.

Driving force for implementation: The restructuring of the railway in the former eastern part of Germany after 1989 necessitated the building of a new power plant with the following characteristics:

- short time for construction of the plant
- high efficiency
- low environmental burden
- low investment and operational costs.

Reference literature: [98, DFIU, 2001].

7.2.4 Techniques to increase the environmental of combustion installations operated on offshore platforms

This section presents techniques for the prevention or reduction of emissions released from combustion installations operated on offshore platforms. They are all currently commercially available. Examples are given in order to illustrate techniques that demonstrate a high environmental performance. The techniques that are given as examples rely on information provided by industry, and on evaluation by the European IPPC Bureau.

EXAMPLE 7.2.4.1 PARAMETRIC EMISSION MODELLING SYSTEM (PEMS)

Description: A continuous emission monitoring systems (CEMS) is the total equipment necessary for the determination of a gas or particulate matter concentration or emission rate, using pollutant analyser measurements and conversion equations, graphs, or computer programs to produce results in units of applicable emission limitation standards.

In order to have a cost effective monitoring system and backup if the CEMS should malfunction, PEMS was developed for gas turbines in the early seventies. Instead of direct monitoring of the NO_X emissions, the PEMS calculate the NO_X emissions from key operation parameters. Examples of such parameters are temperature, pressure and fuel consumption. Today PEMS for turbines, boilers, engines and flares are widely used instead of CEMS in order to monitor NO_X, SO_X,. total hydrocarbons, VOC and CO emissions.

Since PEMS already uses existing sensors from the plant control systems, the investment costs are reduced to only include software development and implementation. Also, the use of existing sensors does not require extra personnel with special skills to handle and calibrate the instrumentation, such as CEMS requires. This is especially valuable for offshore industry. Even though a PEMS needs to be periodically checked using CEMS, PEMS operation costs are significantly lower than with CEMS. Finally, no stack mounted hardware is required with PEMS.

A complete PEMS consists of a mathematical module, a quality assurance module and a report module. The mathematical module can be evaluated in three different ways: (1) first principles, (2) statistical regression and (3) artificial intelligence, neural networks or non-linear regressions. When using the first principles approach, the module is evaluated based on physico-chemical knowledge of NO_X formations. The operational characteristics and the turbine design varies between different types of turbines. The module for each turbine, therefore, has to be tuned by NO_X emission measurements and logged operation parameters to adjust the factors in the module. The statistical regression and artificial intelligence approach requires a set of historical operational data with simultaneous NO_X emission measurements in order to develop the modules.

The quality assurance module consists of a sensor check procedure and a PEMS check procedure. PEMS is not more accurate than the accuracy of the operational parameters used in the PEMS module. Check of the sensor signals is of great importance to detect signal drifts in order to avoid incorrect predictions. A sensor check can be performed by comparing the signals with either the signals from redundant sensors or with calculated values from a mathematical module using signals from other sensors. An alarm is sounded if the system detects a sensordrift. In addition, a complete PEMS should also detect PEMS drift as an extra quality assurance.

PEMS is widely used in the US as a NO_X monitoring technique, and approved as a Best Available Technique in the UK. In the US, the operator of an installation can apply to use PEMS instead of CEMS if the installation can document that the new PEMS has 'the same or better precision, reliability, accessibility, and timeliness as that was provided by the continuous emission monitoring systems'. PEMS accuracy is computed from 720 hours of operation emissions monitoring, both by the alternative PEMS and a verified CEMS. The relative accuracy for CEMS is 20 % in 40 CFR Part 60 and 10 % in 40 CFR Part 75. (CFR = Code of Federal Regulations).

Achieved environmental benefits: Applying modelling can enable gas turbine operators to become more aware of the real-time emission values from equipment. This in itself is a major benefit. As a consequence, the technique can indicate optimum operating points for equipment. This control can be either manual or automatic. One system onshore that drives parallel compressor trains has been used to give an 8 % reduction in CO_2 emissions for a fixed task. The technique can also be used to highlight a deterioration in the gas turbine performance, that might otherwise lead to an increase in NO_X emissions. Where properly administered, this technique can result in lower operating costs.

Applicability: Parametric modelling can be retrofitted to the majority of gas turbines. Some operators prefer this technique to the option of fitting emission monitoring systems, whose disadvantages include large space requirements, poor instrumentation accuracy and high maintenance costs. Specially at offshore installations, PEMS will offer cost-effective solutions for emission monitoring.

Cross-media effects: In particular situations, energy consumption can be reduced, Once installed, there are few disadvantages compared to the option of 'continuous emissions monitoring systems'. Parametric modelling can also build up useful emissions monitoring information that can easily be used to provide the framework for annual emissions reporting.

Operational data:

Economics: The software costs are not likely to exceed EUR 80000 per installation. However, installation and maintenance costs have to be considered. Installation costs depend on the level of instrumentation that already exists and hence what needs to be added so that all the required parameters are monitored. Experience suggests that the installation costs could add another EUR 160000 to the software costs. Once installed, little maintenance is required, though annual verification of emission signatures is required using portable emission meters. The total cost of this will be in the region of about EUR 30000 per year. The PEMS investment costs are about 50 % and the maintenance costs 1/3 of a CEMS. In addition, daily operation will not require any special attention or costs.

Driving force for implementation: Parametric modelling first gained impetus in Norway, where the high levels of CO_2 tax forced operators to evaluate all possible control options available. This driving force has followed through to onshore UK, where parametric modelling has been installed on several gas compression stations – leading to lower fuel costs. This provides accurate and inexpensive NO_X monitoring.

Reference literature: [119, Guinee,], [120, Bakken and Skogly,], [121, Fripp,], [206, Pavilion, 2003], [200, Southern Research Institute, 2000], [201, Macak III, 1996], [202, Lefebvre, 1998], [203, EPA, 2002], [204, The Cadmus Group, 2000], [205, Tronci, et al., 2002].

EXAMPLE 7.2.4.2 POWER INTEGRATION OF MULTIPLE FIELDS

Description: Use of a central power source to a number of participating installations. This can involve either one or two central power stations delivering power via electric cables to other fields. Examples include a ‘mother’ platform supplying power to numerous satellite fields via an underwater cable. Also, a multiple field development being fed as part of a ring main by two central power stations.

Achieved environmental benefits: Power stations offshore are invariably powered by gas turbines. There are inefficiencies in having one power station per platform. There is extensive use of ‘spinning reserve’ to give sufficient margin to maintain production should part of the power generation system fail. Integrating several fields to a central power station can ensure that gas turbine efficiencies are maximised and that the spinning reserve is minimised, thereby reducing both CO_2 and NO_X emissions.

Power integration between installations has been studied and applied in the UK and Norway, and may be economically interesting in specific situations as mentioned. However, the transmission loss should be taken into account when calculating the environmental benefit, which, in most cases, is marginal. The emission reduction can become more significant if the power generation can be based on combined cycle and/or based on low NOx turbines.

Applicability: Power integration is a major capital project that can only be used in specific situations. These include installation of a newly manned or a normally unmanned platform adjacent to a ‘mother’ installation. Retrofitting existing installations to an integrated power distribution network is unlikely to be cost effective, although these schemes are presently being evaluated.

Cross-media effects: Adoption of power integration will invariably lead to reduced power consumption.

Operational data: Reference [125, Evans and McConnell, 1994] summarises the experiences of the Marathon Brae offshore platform, where East Brae was added to the existing field with its power supplied from the existing facilities via underwater cables. Additional platform weight was eliminated, with cost savings in excess of EUR 98 million. An interesting benefit reported was the ability to maintain power to an installation during shutdowns. There is also an onshore example where the producing fields of BP’s Prudhoe Bay in Alaska are supplied from a single power station, again with economic and environmental benefits.

Economics: Power integration is a major capital investment. Cost savings for installation have been reported. However, these costs need to be compared to those for the installation of cable and control equipment.

Driving force for implementation: The implementation of power integration can only be considered in selective cases, and is unlikely to be used to achieve emissions reductions alone. Economic considerations are the main driving force. In the Marathon Brae field, there was a desire to reduce platform costs by maximising the use of existing infrastructure, and utilising surplus power. Emission benefits were achieved as a result.

Reference literature: [125, Evans and McConnell, 1994], [78, Finkeldei, 2000].

EXAMPLE 7.2.4.3 DRY LOW NO_X (DLN) COMBUSTION CHAMBERS APPLIED TO OFFSHORE GAS TURBINES

Description: The basic characteristic of dry low NO_X combustors is that the mixing of air and fuel and combustion take place in two successive steps. By mixing combustion air and fuel before combustion, a homogeneous temperature distribution and a lower flame temperature are achieved, resulting in lower NO_X emissions. Since 1995, 11 new single fuel gas turbines have been applied, such DLN combustion chambers, on Norwegian oil and gas producing platforms. Additionally, two existing gas turbines have been retrofitted from conventional types into DLE type engines.

The DLN gas turbines require an input of fuel gas properties such as CO_2, N_2, compressibility, relative density (specific gravity) and calorific value for engine control.

The engine control system can accommodate small changes of these properties provided they lie within a given tolerance. However, if the changes go outside these tolerances, then active inputs will be required. The most likely parameters that require active inputs are the fuel gas specific gravity and calorific value. Consequently, offshore installations often require devices such as calorimeters or chromatographs for the online monitoring of the fuel gas.

Achieved environmental benefits: Low levels of NO_X emissions. However, the environmental benefit will be marginal for turbines operating on part-load and in cases where varying load leads to frequent turbine trips and consequent flaring.

Applicability: DLN combustion systems are available for a number of new gas turbines. For retrofitting existing gas turbines there are mainly two technical limitations. One limit is related to the fuel system. Turbines that have dual fuel (gas and diesel) capability are not yet considered mature. The second limit is related to the age of the equipment. The retrofit requires a significant upgrade of the control as well, so there is certain additional space required in combination with the gas manifold. This might not be available. Some of the packages have all the utility equipment placed inside the hood.

Gas turbines have been used for decades as a reliable prime mover on offshore production facilities. The introduction of this new combustion technology has not been without certain risks. The operation of the turbines has been challenging both with respect to availability and performance at those facilities experiencing certain changes of gas properties or ambient temperatures. The lean premixing combustor technology (DLN) is beginning to reach the necessary state of maturity for use on offshore facilities.

Operational experience so far indicates lower reliability of DLN turbines than turbines with conventional burners, resulting in more frequent process shutdowns and flaring. This is partly due to the higher operational complexity of the DLN. Some improvements have been recorded as a part of a ‘learning curve’, but some of the problems are due to fundamental characteristics of the technology that cannot easily be cured.

Cross-media effects: Low levels of NO_X emissions may result in higher emissions of CO and unburned hydrocarbons (UHC). The prevailing turbine type in the Norwegian sector will have lower thermal efficiency with low NOx equipment, especially on part-load, than conventional turbines. The loss in efficiency on part-load may be as much as 13 %, which means that CO_2 emissions would increase by up to 13%.

Operational data: At full load, a normal gas turbine has an emission figure of approx. 360 mg/Nm^3 NO_X (at 15 % oxygen), while under similar conditions, the DLN version produces around 50 mg/Nm^3 NO_X (at 15 % oxygen) and 30 mg/Nm^3 of CO at 75 – 100 % load measured under ISO conditions.

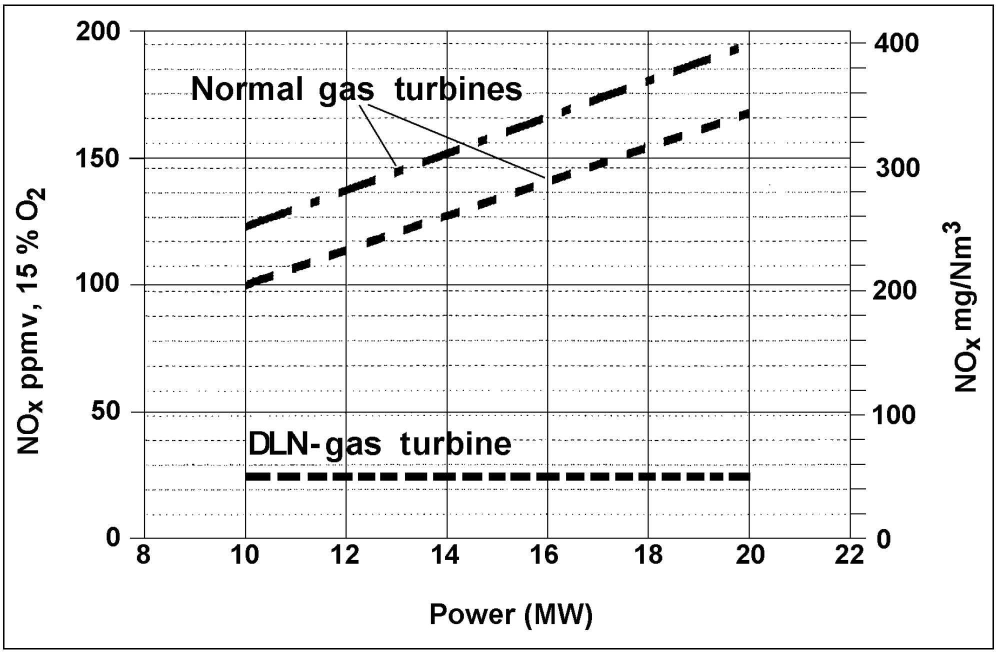


Figure 7.19: NO_X emissions from offshore gas turbines with a DLN combustion chamber [122, Carstensen and Skorping, 2000]

Economics: The required shutdown period during installation, and the associated economic loss due to deferred or lost production, as well as the increased maintenance costs are significantly higher than previous assessments have indicated. A cost benefit analysis showed a great range of costs per unit of NO_X reduced, ranging from 23 NOK/kg NO_X (3 EUR/kg) to nearly 1000 NOK/kg (125 EUR/kg). Only 20% of the turbines could be retrofitted at a cost of less than 100 NOK/kg NO_X (12 EUR/kg NO_X).

Driving force for implementation: Low emission limit values of NO_X

Reference literature: [122, Carstensen and Skorping, 2000], [78, Finkeldei, 2000].

EXAMPLE 7.2.4.4 REDUCTION OF LOADS ON GAS TURBINE DRIVEN EQUIPMENT

Description: The turbine driven equipment includes: compressors, pumps, and power generation equipment. This equipment may be directly driven by a gas turbine, or driven indirectly by an electric motor which derives its power from a gas turbine. Reduction of the load can have both environmental and cost benefits to operators. Examples of ways to reduce load include:

- reduction of compressor recycling
- reduction of pump bypass quantities
- process control loop tuning of the plant.

Achieved environmental benefits: A reduction of the load to gas turbines invariably means a reduction in fuel consumption, and hence a reduction in CO_2 emissions. In general, as the gas turbines are generally then operated at lower speeds there can also be significant reductions in NO_X emissions. Flaring quantities have also often been reduced as plant stability is improved.

Applicability: Techniques to reduce loads are applicable to all gas turbines as they generally provide power, either directly or indirectly, to all items of equipment on an installation.

Cross-media effects: In extreme cases, the amount of driven equipment can be reduced. i.e. three pumps reduced to two, and so again costs can be reduced. Similarly, the power generation spinning reserve can be reduced.

Operational data: Experience suggests that there are significant gains to be made by simple adjustments to the plant. For example, on some installations there is a high percentage of process control loops in manual configuration. These loops can be properly tuned and put in automatic mode. Consequently, such variables as pressure settings can be reduced, which in turn reduce driven loads. The number of unplanned shutdowns can be reduced, which in turn leads to less flaring. Time spent correctly setting surge protection lines of centrifugal compressors can be equally beneficial. A key aspect here is improving the awareness of plant personnel to the benefits of reducing inefficiencies.

Economics: Most of the changes in this technique require little modification to equipment. Instead, the changes are to the control of the plant and so require little capital expenditure. Correct tuning of key loops for an installation can be achieved for less than GBP 25000. Training of key personnel can be another GBP 10000. Consequently, there is often an increase in production with an increase in plant stability.

Driving force for implementation: Historically, there has been little driving force to implement such changes. Operators had little confidence in the manual techniques for control loop tuning, etc. Software techniques are now available to enable such delicate changes as loop tuning to be confidently made. Many operators have since realised the benefits and have implemented such techniques to create robust systems.

Reference literature: [78, Finkeldei, 2000], [207, Underbakke and Jakobsen,]

EXAMPLE 7.2.4.5 COMBINED CYCLE HEAT AND POWER UNIT OF OFFSHORE INSTALLATIONS

Description: Increasing fuel costs and concerns about emissions have directed attention to energy conservation on offshore oil and gas installations. This has stimulated significant changes in operational procedures and technology development on several oil and gas installations. Focus has increased on keeping the power requirement down, avoiding unnecessary fuel consumption and designing more energy efficient systems. The most efficient way of achieving this is by installing cold process flares and steam cycles on existing or new gas turbines to form combined cycles (CC).

The combined cycle concept is a combination of a gas turbine process and a steam turbine process. The gas turbine exhaust normally exits the gas turbine at approximately 500 °C. This represents a large amount of energy, which is recovered by producing steam under pressure in waste-heat recovery units. The steam is routed to the steam turbine, which produces additional power. The low pressure steam from the steam turbine outlet is condensed by using cooling water (seawater), and then routed back to the waste heat recovery unit for steam generation (WHRU-SG). The WHRU-SG and the steam turbine from a steam bottoming cycle, which is a closed circuit steam cycle. This is conventional technology in onshore gas-fired power plants.

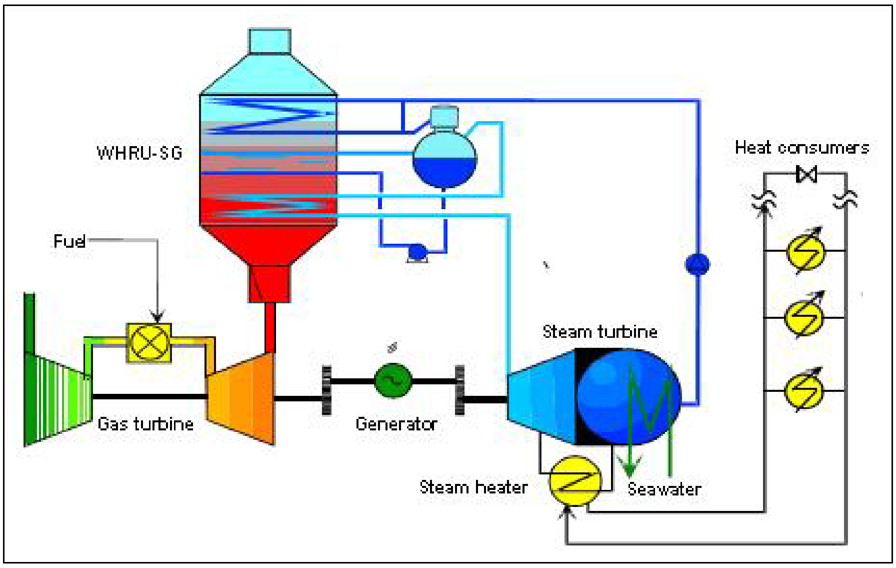


Figure 7.20: Flow diagram of the combined cycle heat and power plant offshore [25, ABB, 2000]

Achieved environmental benefits: A typical efficiency increase from ‘simple cycle’ to combined cycle offshore based on new gas turbines will be from 37 to 50 %. This will reduce fuel consumption and emissions of CO_2 and NO_X by typically 25 %. Compared to larger onshore utility combined cycle plants, the thermal efficiency is lower due to the trade-off made between cost and efficiency and the fact that larger onshore plants have lower thermal losses.

Combined with the extraction of steam from the steam turbine, the ‘combined cycle plant’ is transformed to a ‘combined heat and power plant’ (CHP). The extracted steam can cover heat demands indirectly by the production of liquid heating medium, or alternatively, steam can be directly used in process heaters. Depending on the magnitude of the heat demand, the efficiency of a CHP will be from 47 to 80 %. The CC and CHP plants are very flexible, as heat recovery may be maximised at all times regardless of the load level or the heat demand.

Applicability: The need to watch investment costs and weight whilst pursuing new technology and optimisation efficiency has brought the weight of the heat recovery unit down 30 % to 50 %. As an example, a single inlet heat recovery unit for a gas turbine has a weight of approx. 125 tonnes, while standard units are normally 200 to 250 tonnes. The space requirement for a waste heat recovery unit for steam generation is about 25 to 50 % extra compared to conventional process heat production. However, these heat recovery units are placed on top of the gas turbines, which are normally placed at the top of the platform. Thus, the space required is normally available.

The relatively low steam conditions enables the use of low pressure steam turbine modules with welded turbine casing. As a result, the weight of a steam turbine skid for 15 to 20 MW will be 150 to 175 tonnes, which is close to the weight of a comparable gas turbine. Such a skid will be about the same size as for a 20 MW gas turbine skid.

The conclusion is that a combined cycle plant is in general applicable for both new and retrofit offshore applications.

Figure 7.21: Example of a combined cycle power plant installed on an offshore platform on the Norwegian continental shelf
[25, ABB, 2000]

Cross-media effects: As the combined cycle concept only involves ultra-pure water in a closed circuit, no waste products are disposed of to the environment under normal operation.

Operational data: The following operational data are based on a combined cycle with a total power production of 67 MW:

steam pressure at steam turbine inlet:	15 bar
steam temperature at steam turbine inlet:	430 °C
steam mass flow at steam turbine inlet:	17.5 kg/s
rated power output at steam turbine generator:	15.8 MW_e

The steam data given are based on heat recovery from hot exhaust gases from two conventional gas turbines with the following exhaust data:

exhaust gas temperature:	481 °C
rated power output:	2 x 25.9 MW_e.

An offshore steam cycle will then typically recover one third of the rated power production of a conventional gas turbine.

The steam cycle requires seawater as the cooling medium in the steam condenser. The steam turbine requires a seawater flow of approximately 2000 m^3/h. Seawater system investment costs can sometimes be reduced by integration with other seawater users. The cost of cooling water varies a lot from case to case, and on some platforms the cost of providing cooling water for a retrofit can be very high.

In addition, the steam cycle requires a small amount of electricity and instrument air to operate pumps and valves. A small amount of ammonia (typically 1 kg/day) is added to the steam cycle to control the pH. The water consumption is typically around 0.5 m^3/h.

Economics: The estimated cost numbers presented refer to a typical 16 MW steam power plant fitted to two gas turbines instead of one conventional gas turbine. The total power production for the combined cycle plant will then be in the range of 67 MW. On an offshore platform total project costs are strongly linked to space and weight. It should be noted that for oil platforms, gas, in many cases, is a free or nearly free commodity. Reduced gas consumption during the oil production phase will increase the volume of gas that has to be reinjected. In cases where gas compression capacity is a limiting factor, this may in fact reduce the oil production capacity and hence there may be negative economic incentives against fuel gas saving. The value of the saved gas will only be recovered late in the lifetime of the facility, and this will have a low net present value. However, in the Norwegian sector, reduced CO_2 tax may, in specific cases, justify such investments.

Driving force for implementation: Demands for reduced CO_2 and NO_X emissions, CO_2 taxes in the Norwegian shelf and improved operational stability and reliability.

Reference literature: [25, ABB, 2000].

7.3 Current consumption and emission levels

7.3.1 Mass stream overview

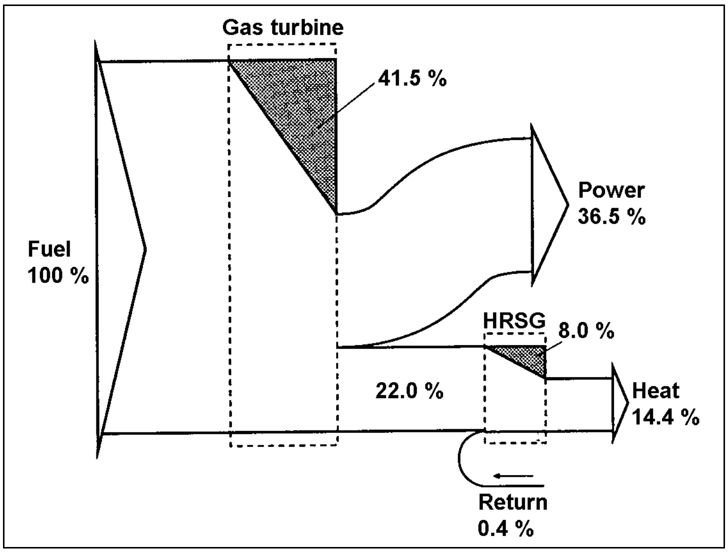


Figure 7.22: Grassmann diagram of a gas turbine with HRSG
[50, Korobitsyn, 1998]

The Grassmann diagram shows the energy flow though a combined cycle gas turbine without supplementary firing. The grey marked areas represent the internal losses of energy in the turbine and the heat recovery steam generator (HRSG).

7.3.2 Overview of gaseous fuels used in large combustion plants

Natural gas is a clean fuel causing practically no SO_2 or particulate emissions. The CO_2 emissions from natural gas combustion are inherently far lower than from other fossil fuels. Table 7.22 gives an overview of the relevant gaseous fuels fired in large combustion plants.

Substance	Natural gas (mol %)	Blast furnace gas (BFG) (mol %)	Refinery gas (mol %) *
N_2	0 – 14	52 – 57	0
CO_2	1 – 2	20 – 21	4 – 5
$CH_4 – C_4H_{10}$	84 – 99	0	0 – 46
CO	0	21 – 23	20 – 50
H_2	0	2 – 4	30 – 45
Sulphur	0	Some	20 – 1700 mg H_2S/Nm^3
Dust	0	Depends on the applied gas cleaning system, but normally <40 mg/Nm^3	0
* See Refinery BREF. Range depends on the type of gas (e.g. refinery gas, hydrogen gas, coke gas, FCC gas)			

Table 7.22: Overview of the relevant gaseous fuels fired in large combustion plants
[58, Eurelectric, 2001]

Offshore gas turbines burn crude natural gas supplied directly by the adjacent oilfield. This gas can have a different composition from that of natural gas normally used for onshore gas turbines. A typical composition of natural gas from an oil field in the North Sea can be seen in Table 7.23.

Component	Mol %	g/mol
Methane	68.69	46.18
CO_2 (1)	14.65	27.01
Ethane	8.18	10.31
Propane	4.45	8.22
n-Butane	1.19	2.9
Nitrogen	0.84	0.98
H_2O	0.7	0.52
i-Butane	0.49	1.3
n-Pentane	0.30	0.92
i-Pentane	0.26	0.78
Hexane	0.089	0.32
Heptane	0.06	0.25
Octane	0.033	0.15
H_2S	0.007	0.01
Helium	0.0	0.0
(1) The CO_2 content of crude natural gas varies quite a bit from field to field but it is rarely above 10 %.		

Table 7.23: An example composition of crude natural gas from an oil field in the North Sea [78, Finkeldei, 2000]

More information on natural gas and refinery gases is available in the Mineral Oil and Gas Refinery BREF.

7.3.3 The efficiency of gaseous fuel-fired combustion plants

The efficiency of power plants has increased continuously during the last decade by optimisation of the process and by new developments in the field of materials and cooling techniques, which make higher turbine inlet temperatures possible. In a combined cycle, the application of more pressure stages and the increase of allowable steam inlet temperatures (possible by the development of high temperature resistant materials) cause efficiency increases of the steam cycle too. Table 7.24 gives an overview of the efficiencies of gas fired power plants, designed for electricity production at base load. It should be emphasised that the efficiency values quoted apply to new, clean gas turbines at full load and ISO conditions and once-through cooled condensers. For other conditions, the values may be lower, as efficiency strongly depends on ambient conditions and the type of cooling system applied, as well as on the operating mode.

	Maximum unit size (MW_e)	Thermal efficiencies (%)
Conventional power station		38 – 49
Simple cycle gas turbine	275	30 – 42
Simple cycle spark-ignited (SG) or dual fuel engines.		40 – 47
Combined cycle with HRSG	400	46 – 58
Topping cycle with hot wind box		50
Notes: These data have been obtained during full load operation. If the load operation decreases, thermal efficiencies decrease significantly.		

Table 7.24: Overview of efficiencies of gas fired LCPs

The reason for the highest efficiency of the combined cycle is that the gas turbine gives 65 to 70 % of the total capacity and the energy conversion in the gas turbine is very effective in using relatively hot gases in the turbine.

An increased unit efficiency is possible due to the increased firing temperature of the gas turbine and the increased gas turbine exhaust temperature, which results in higher superheated steam temperatures and allows the use of dual or triple pressure heat recovery steam generators. If the exhaust temperature is high enough, a steam reheat is economically attractive.

Various process modifications can be applied to improve the thermal efficiency of gas turbines. For example, regeneration may improve efficiency by transferring waste heat to the compressor discharge air, thus reducing fuel consumption but on the other hand may also result in a certain reduction of power. Co-generation is an arrangement where the energy released in a combustion process is used to produce both electricity and useful heat. The electricity may be generated either using the hot combustion gases directly, as in a gas turbine, or by using them to produce high temperature and pressure steam to drive a steam turbine, as in a conventional boiler. The useful heat is usually provided in the form of steam. This steam may be withdrawn directly or via a heat-exchanger in the case of a conventional boiler or through the use of a heat recovery steam generator (HRSG) extracting energy from the exhaust gases, in the case of a combustion turbine. High quality fuels must be used for combined cycle plants with HRSG to avoid corrosion/erosion problems. The heat produced may be used in different applications, e.g. in industrial processes, district heating, etc.

Some effects must be considered which diminish efficiency in real operating cycles, such as inefficiency in compression and expansion, loss of pressure during heat addition and rejection, variation of working fluid specific heat with temperature, incomplete combustion, etc. [87, Molero de Blas, 1995].

7.3.4 Emissions to air

In gas-fired combustion installations, particularly gas turbines, the generation of NO_X emissions is mainly due to the formation of thermal NO_X, which is influenced by the following parameters [32, Rentz, et al., 1999]:

- **fuel composition:** as the hydrogen content of the fuel increases, NO_X emissions increase. Higher alkane content in the natural gas tends also to increase the NO_X emission
- **flame temperature:** When fuel and air are combusted at a stoichiometric ratio, the highest flame temperature is reached, resulting in the highest NO_X emissions
- **retention time of the fuel/air mixture in the combustion zone:** The retention time can be reduced by using an increased number of burners with a constant fuel and airflow. This is a way to reduce NO_X formation and was applied at an early stage in gas turbine development
- **atmospheric conditions:** An increase of humidity in combustion air also helps to reduce NO_X formation. The effect causes a reduced flame temperature, which is similar to the injection of a water/fuel-emulsion into the combustion chamber of the gas turbine.

The precise exhaust concentration of NO_X to be achieved depends on the type of gas turbine. However, there is a conflict between increasing gas turbine efficiency and reducing the NO_X emissions (high gas turbine efficiency is, of course, also highly important since less fuel is needed). The aim to increase the gas turbine efficiency leads to higher firing temperatures in the gas turbine. As a consequence, measures taken to reduce NO_X emissions will be less effective. Nevertheless, newly built high efficiency combined cycle installations with dry low NOx combustion chambers can achieve exhaust concentrations of 20 – 50 mg/Nm^3 without using ‘end-of-pipe’ NO_X reducing measures. (see Table 7.25). The NO_X emission of existing installations cannot be presented with one single figure, but varies between 50 and 75 mg/Nm^3, although old installations may find difficulty in staying below the 75 mg/Nm^3 level. However, it should be noted, that low emission levels of NO_X may lead to higher CO emissions.

With increasing temperature, the NO_X emission level increases slower than the efficiency of electricity generation. For this reason, technical development to higher efficiencies implies a higher NO_X level in mg/Nm³.

Type of gas turbine	Power (MW at ISO conditions)	Off-gas temperature (°C)	Off-gas volume (kg/s)	Emission of NO_X(ppm) at 15 % O_2 and ISO condition
GE Frame 6	38.34	539	136.98	25
W 251 B12	49.1	520	171.46	9 – 25 (9 ppm since 1997)
ABB GTBC	52.6	517	179.17	25
Siemens V64.3	60.5	534	183.7	25
GE Frame 7EA	83.5	530	292.11	9
ABB GTI INI	83.8	505	317.06	15
Siemens V 84.2	106.7	548	346.99	9
ABB GTI In2	109.2	525	375.12	15
W 501 D5	109.8	527	361.97	9 – 25 (9 ppm since 1996)
GE Frame 9E	123.4	538	403.7	9 – 25 (9 ppm since 1996)
ABB GT 13 E	147.9	516	501.22	25
Siemens V 84.3	152	550	425.01	25
Siemens V94.2	153.6	546	498.95	9
GE Frame 7 FA	159	589	417.75	9
W 501 F	161.3	583	430.46	9 – 15 (9 ppm since 1995)
ABB 13E2	164.3	525	524.81	25
GE 9FA	226.5	589	601.92	9 – 25 (9 ppm since 1997)
Notes: GE = General Electric Co. W = Westinghouse ABB Asea Brown Boveri Siemens = Siemens KWU				

Table 7.25: Selected parameters and the NO_X emission levels for new gas turbines [185, Smith, 1995]

Since no major technical problems with waste heat boilers (combined cycle, co-generation) have been observed with gas turbines equipped with SCR technology, SCR can be seen as a proven technique to reduce NO_X emissions from gas-fired installations. As disadvantages of SCR, the pressure loss, and the connected loss in efficiency, as well as possible emissions of ammonia have to be taken into account in the integrated pollution prevention approach. According to [32, Rentz, et al., 1999], 20 mg/Nm^3 are achieved in California by using the SCR. At that site, NO_X emission values of 20 mg/Nm^3 and less have to be met since ambient air conditions are worse for most of the year due to an extremely high ozone concentration or continuous summer smog periods. In Japan and in Europe, 30 – 50 mg/Nm^3 for large gas turbines (>100 MW_{th}) can be achieved with natural gas firing.

The use of dry low NO_X systems in a gas turbine can achieve 9 – 42 ppmvd NO_X (15 % O_2), 9 - 50 ppmvd (15 % O_2) for gas. When using distillate as fuel, the use of dry low NO_X systems can achieve 42 – 90 ppmvd NO_X (15 % O_2), 20 – 30 ppmvd (15 % O_2) [190, Davis and Black, 2000].

The most important parameter governing the rate of NO_X formation in internal combustion engines is the gas combustion temperature. One method to reduce the combustion temperature is to lower the fuel/air ratio – the same specific heat quantity released by the combustion of the fuel is then used to heat up a larger mass of exhaust gases, resulting in a lower maximum combustion temperature and low NO_X emissions. This primary NO_X reduction measure called ‘the lean-burn approach’ is used in some gas fired engines. Spark-ignited lean-burn (SG) and dual fuel (DF) engines in gas mode are often equipped with an oxidation catalyst mainly for CO removal. The NMVOC (non methane volatile organic compound) emission from spark-ignited lean-burn gas (SG) and dual fuel (DF) engines in gas mode depend on the natural gas composition. Depending on the legislation in force and the composition of the natural gas, NMVOC secondary emission reduction techniques might, in some cases, be needed and oxidation catalyst for simultaneous CO and NMVOC reduction are then applied.

Installation	Used fuel oil or SO_2	NO_X (as NO_2)* (mg/Nm^3)	Average dust (ISO 9096 or equivalent other method)	Remarks
Gas diesel, Gas mode	natural gas main fuel, pilot fuel: heavy fuel oil (2.9 wt-% S, 0.05 wt-% ash, 9 wt-% micro carbon residue)	1584 – 1612	10 … 13	120 MWe power plant in Asia
Spark ignited gas engine, (SG)	N/A	161 – 190	N/A	5 MWe plant in Northern Europe
Spark ignited gas engine, SG (low NO_X tuned)	N/A	71 – 83	N/A	40 MWe plant in Americas. Fuel consumption about 3 % higher compared to ‘normal’ rated SG.
Spark-ignited gas engine, SG		5 - 13		SCR (15 % O_2)
Dual fuel engine - gas mode - LFO mode	<0.05 wt-% S, <0.01wt-% ash	147 – 177 1531 – 1751	N/A 6 – 27	5 MW_e plant in Northern Europe
* NO_X emission given at 0ºC, 101.3 kPa at 15 vol-% O_2, dry gas				

Table 7.26: NO_X emissions for steady state full engine load
[192, TWG, 2003]

The efficient combustion of gaseous fuels does not generate particulates. However, the local effects dominates the inlet particulate levels that may affect turbines [191, GE, 2002].

Combustion technique	Capacity (MW_{th})	Emission reduction measures	Emissions to air (mg/Nm^3)			Remarks
			NO_X	Dust	CO	
Gas-fired boiler	50 – 100		60 – 93	2 – 5.4	7 – 14	All these values are in mg/Nm^3 at 3 % O_2. Smaller industrial boilers in the 20 – 50MW(th) range has been reported that can achieve emission limits of around 140 mg/m^3 at 3% oxygen, dry gas basis, 273K
		without reduction measures	300		100	
		primary measures	150		100	
			150 – 200			
	100 – 300					
	>300		60 – 180			
Gas turbine combined cycle combustion (natural gas)	>50	SCONOX	<6		<1.1 mg/Nm^3 (1ppm)	Retrofitted to an existing 32 MW_e co-generation unit and a small 5 MW_e gas turbine, both operated in the US Technique can be applied to plants over 50 MW_{th}
	50 – 100					NO_X levels of less than 50 mg/Nm^3 are achieved
	100 – 300	Pm (DLN)	18 – 41.6		0.1 – 11.3	NO_X levels of less than 50 mg/Nm^3 are achieved
		Pm (water injection)	80 – 200		<50	
	>300	Pm (DLN)	<30		<30	This plant has also applied an SCR system which is no longer in operation because of the high performance of the DLN technology
		Pm (two stage LNB)	47 – 73		6 – 60	
		Pm/SCR	33	<1	30	<2
Gas turbine offshore	50 – 100		65 – 355		<8 – 668	Gas turbines 41.9 – 79 MW_{th} burning North Sea crude natural gas
Gas turbine fired with natural gas	50 – 100	Pm (water injection)	30 – 57	5 - 7	<30	At 15 % O_2
		DLN	18 – 35			At 15 % O_2
		Pm (water injection)	50 – 90			At 15 % O_2
	100 – 300					
	>300	DLN	50			
Notes: Pm (..) Primary measures to NO_X emissions DLN Dry low NO_x combustion chamber SCR Selective catalytic reduction						

Table 7.27: Emissions to air from gaseous-fuel-fired combustion plants

7.3.5 Emissions to water

The operation of gas-fired boilers and turbines leads to the following specific waste water:

- **scrubbing leakage and rinsing water:** the scrubbing, leakage and rinsing water will be carried off to the sewer via an oil separator. The amount will normally be about 0.1 m^3/h. It can be contaminated with oil. A peak amount of 150 m^3/h occurs if the pipelines have to be flushed. The contamination would then consist mainly of sediment. Oil is not expected. Gas turbine compressors need to be cleaned about four times a year with water and detergent. The type of detergent is not yet established. When the detergent used is biologically degradable it is discharged to the surface water. If heavy metals are present, the water is collected and disposed of off-site by an authorised contractor
- **boiler water blowdown:** the boiler water that is drained from the boiler for maintenance purposes will be collected and could be treated in a neutralisation basin. After neutralisation the water will be discharged to the surface water. The boiler water is demineralised water with supplementary chemicals. The boiler should be drained once a year. The salt content in the water/steam circuit should remain below a certain value to prevent depositions in evaporation and over-heating pipes and to prevent accelerated corrosion. To keep the salt level in the specified range, boiler water is regularly (if necessary) blown down from the drum to the cooling water system. Consequently, the blowdown water will contain low salt concentrations
- **blowdown from demineralisation installation:**

7.3.6 Combustion and other plant residues

Solid and liquid residues: only small quantities of solid and liquid residues are produced by the operation of gas turbines and gas fired boilers. Most of the residues will be the product of subsidiary activities, such as maintenance and water treatment. The waste substances associated with these subsidiary activities may include scrap metal, used oil, packaging materials, liquids used to wash down the compressors/gas turbines, ion exchangers, and activated carbon.

Used oil: normally the turbine control oil and lubricating oil will be changed every ten years. They may also be changed shortly after commissioning. The quantity of oil involved on each occasion will be about 30000 to 40000 l per unit of 400 MW_e.

Cleaning liquids: the liquids used to wash the compressors and turbines will be synthetic detergents dissolved in water. These liquids will be used periodically to remove dirt and grease deposits from the blades; cleaning will take place during shutdown periods. The resulting dirty liquids have to be sent to an authorised processor. The total quantity of such liquids produced is estimated to be 7 m^3 per unit each time offline cleaning is performed (four times a year).

Demineralised water chemicals: the demineralised water installation will produce waste chemicals and resins. If an ion exchange installation is used, the chemicals used, are chloric acid and caustic soda. The salts will normally be discharged into the surface water after neutralisation. The resins have to be changed once every three to five years. The amounts of chemicals used and the waste resins depend on the kind of installation, the raw water quality and the amount of demineralised water produced.

7.3.7 Noise emission

Most EU countries have their own environmental noise regulations, which have to be met.

Typically, the noise criteria is based on different area types: land use (residential, commercial, industrial, etc.) A further common practice is to use different quantities for day and night, especially for residential areas (night is typically between 22.00 hrs and 07.00 hrs). Industrial areas usually have only onequantity: if the power plant is a base load plant, the night time (if stipulated) value is used as the design basis.

The environmental noise requirement is defined with a noise receptor outside the project property boundary line. Also existing background noise must be taken into account when defining the noise impact from a new power plant.

The determination of reasonable noise requirements is necessary to avoid needless costs. For example, if the background noise in an industrial area is already 70 dB(A) it does not give any added value to design a plant for a 60 dB(A) noise impact or lower. For noise within the plant – in areas where the noise level exceeds 85 dB(A) ear protection must be used and these areas must be clearly marked. In other locations where people may stay for longer periods, the noise level should be able to be lowered if needed.

The main noise sources of thermal power plants are: fans (including inlets, outlets, stacks and enclosures), pumps, turbines, steam systems, buildings (including windows and ventilation systems), cooling towers and transformers (audible tones 100 Hz and harmonics).

7.4 Techniques to consider in the determination of BAT for the combustion of gaseous fuels

This section presents techniques, that are considered in the determination of BAT for the prevention or reduction of emissions from the combustion of gaseous fuels and for increasing the thermal efficiency. They are all currently commercially available. In this section, the techniques to be considered have been described in a general way, but for most of the techniques, detailed descriptions are presented in Chapter 3 and for some techniques examples are given in Section 7.2 in order to demonstrate, in detail, the environmental performance of these techniques when applied in a ‘real situation’. In principle, techniques described in Chapter 3 apply, to a large extent, to the combustion of gaseous fuels and should, in general, also be seen as techniques to consider in the determination of BAT.

To avoid duplication throughout this document, refer to Environmental Management Systems (EMS) in Section 3.15.

7.4.1 Techniques for the supply and handling of gaseous fuel and liquid additives

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Use of an expansion turbine to recover the energy content of the pressurised gases delivered by gas pipelines	More efficient use of energy	Possible	Possible	High	None	Not available	
Preheating of fuel gas by recovering the off-gas energy content							
Regular checks of the gas delivering facilities and piping	Reduced risk of fire hazards						
Sealed surfaces with drainage systems (including oil separators to avoid water and soil contamination cased by lubrication oil)	Prevention of soil and groundwater contamination	Possible	Possible	High	None	Cost for waste water treatment	Collected drainage water needs to be treated in a settling pond
In the case of SCR, storage of ammonia as ammonia-water solution	Higher safety	Possible	Possible	High	Less risk than from storage as pressurised liquid ammonia	Not available	

Table 7.28: Techniques for the supply and handling of gaseous fuel and liquid additives

7.4.2 Techniques to increase the efficiency of gaseous-fuel-fired boilers and turbines

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Combustion cycle							
Co-generation of heat and power (CHP)	Increased efficiency (fuel utilisation)	Possible	Limited	High			
Preheating of fuel gas by using waste heat	More efficient use of energy	Possible	Possible	High	None	Not available	
Use of advanced materials to reach high operating temperatures and thus increased steam turbine efficiencies	Increased efficiency	Possible	Not possible	Practised in new plants	None	Not available	The use of advanced materials allows higher pressures and temperatures
Double reheat	Increased efficiency	Possible	Not possible	Practised mainly in new plants	None	Not available	
Regenerative feed-water heating	Increased efficiency	Possible	Sometimes possible		None	Not available	
Advanced computerised control of combustion conditions for emission reduction and boiler performance	Increased boiler efficiency	Possible	Possible	High	None	Plant specific	
Heat accumulation (heat storage)		Possible	Possible			Not available	Increases the energy generated with CHP mode
Preheating of combustion air	Increased efficiency	Possible	Possible	High	None	Not available	If preheating temperature higher than 150 ºC, NO_X emissions tend to increase
Gas turbines							
Advanced computerised control of the gas turbine and subsequent recovery boilers	Increased boiler efficiency	Possible	Possible	High	None	Plant specific	
Use of advanced materials to reach high operating temperatures and pressures thus increased gas turbine efficiencies	Increased efficiency	Possible	Not possible	Practised in new plants	None	Not available	The use of advanced materials allows higher pressures and temperatures

Table 7.29: Techniques to increase the efficiency of gaseous-fuel-fired boilers and turbines

7.4.3 Techniques for the prevention and control of NO_X and CO emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Gas fired boilers							
Low excess air	Reduction of NO_X and increased efficiency	Possible	Possible	High		Plant specific	
Flue-gas recirculation	Reduction of NO_X	Possible	Possible	High		Plant specific	
Low NO_x burners for gas fired boilers	Reduction of NO_X	Possible	Possible	High			Older plants may have problems according to the flame length of modern low NO_X burners
Selective catalytic reduction (SCR)	Reduction of NO_X	Possible	Possible	High	Ammonia slip	Plant specific	
Gas turbines							
Direct steam injection	Reduction of NO_X	-	Possible	High			
Direct water injection	Reduction of NO_X	-	Possible	High		Table 7.2	
Dry low NO_X combustion chamber	Reduction of NO_X	Standard	Depending on the specific gas turbine	High		Table 7.2	Today, almost all industrial new uses of gas turbines are equipped with dry low NO_X (DLN) systems. In cases where the conversion of old GTs is possible, costs can be very high, up to 50 % of the costs of a new turbine
Selective catalytic reduction (SCR)	Reduction of NO_X	Possible	Possible	High	Ammonia slip	Table 7.2	Depending on specific situation
CO oxidation catalyst	Reduction (conversion) of CO into CO_2	Possible	Possible	High			Depending on specific situation
Catalytic combustion	Reduction of NO_X	Possible	-	No	No ammonia slip	Table 7.2	Catalytic combustor technology which is a very promising technology is just entering commercial service in the US. Information provided by the manufacturers are not generally based on ‘demonstrated in practice’ installations. Very low NO_X emission down to about 5 – 6 mg/Nm^3 are estimated

Table 7.30: Techniques for the prevention and control of NO_X and CO emissions

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Stationary gas engines							
Selective catalytic reduction (SCR)	Reduction of NO_X	Possible	Possible	High	Ammonia slip	Plant specific	
Lean-burn Concept	Reduction of NO_X	Possible	Not possible	High			Spark-ignited lean-burn (SG) and dual fuel (DF) engines in gas mode are often equipped with an oxidation catalyst mainly for CO removal. The NMVOC emission from spark-ignited lean-burn gas (SG) engines and dual fuel (DF) engines in gas mode depend on the natural gas composition.

Table 7.31: Techniques for the prevention and control of NO_X and CO emissions

7.4.4 Techniques for the prevention and control of water pollution

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Regeneration of demineralisers and condensate polishers							
Neutralisation and sedimentation	Reduced waste water discharge	Possible	Possible	High	Sludge that needs to be dewatered to be disposed of	Plant specific	
Elutriation							
Neutralisation		Only in case of alkaline operation		High		Plant specific	
Washing of boilers, gas turbines, air preheater and precipitator							
Neutralisation and closed loop operation, or replacement by dry cleaning methods where technically possible	Reduced waste water discharge	Possible	Possible	High		Plant specific	
Surface run-off							
Sedimentations or chemical treatment and internal re-use	Reduced waste water discharge	Possible	Possible	High		Plant specific	

Table 7.32: Techniques for the prevention and control of water pollution

7.4.5 Techniques to consider in the determination of BAT for offshore installations

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Co-generation of heat and power (CHP)	Increased efficiency	Possible	Limited	Limited			The combined production of heat and power is also suitable for installations on offshore platforms but the required space must be available and the additional weight needs to be taken into account
Power integration of multiple fields or platforms	Better use of energy generation equipment and thus less emissions	Depends very much on the specific location of the offshore platforms and the oil field		Limited		Major cost investment	For more information see example 7.2.4.2
Optimisation of energy consuming equipment	Less energy consumption means less emissions	Possible	Possible	High			
Parametric modelling	Optimisation of turbine operation and thus reduced emissions	Possible	Possible	High			
Direct steam injection	Reduction of NO_X	Possible	Possible				Water must be at least 'high pressure boiler feed-water' quality, and such quality and quantities are not usually readily available on an offshore facility
Direct water injection	Reduction of NO_X	Possible	Possible				
NO_XRED-GT	Reduction of NO_X	Possible	Possible				
PEMS (parametric emission monitoring system)	Better emission monitoring	Possible	Possible	Hugh			
Cheng steam injection cycle	Simultaneously NO_X reduction and efficiency increase						

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	**Retrofitable**				
Dry low NO_X combustion chamber (DLN)	Reduction of NO_X	Standard technique for new gas turbines	Possible, available as retrofitting package but not for all turbine types	DLN has jet not been applied very often to gas turbines operated offshore			DLN techniques are installed more frequently on the mechanical drive applications. This is because 44 % of the electricity generating gas turbines operated offshore are of the 'dual fuel' type. Turbines that combine lean premix features as well as liquid fuel capability have not yet achieved any field experience and, therefore, not been applied to such turbines
Lean-burn concept	Reduction of NO_X	Possible	Not possible	High			
Selective catalytic reduction (SCR)	Reduction of NO_X				Ammonia slip	Plant specific	According to the space and weight of such a system and particularly the health and safety problems by storage and handling of ammonia on an offshore platform, this technique has not been applied and is not considered particularly viable for offshore combustion installations at the present time.
Cheng steam injection cycle	Simultaneously NO_X reduction and efficiency increase	Possible					

Table 7.33: Techniques to consider in the determination of BAT for offshore installations

7.5 Best available techniques (BAT) for the combustion of gaseous fuels

In understanding this section and its contents, the attention of the reader is drawn back to the preface of this document and in particular the fifth section of the preface: ‘How to understand and use this document’. The techniques and associated emission and/or consumption levels, or ranges of levels, presented in this section have been assessed through an iterative process involving the following steps:

- identification of the key environmental issues for the sector; which are emissions to air and water, thermal efficiency and combustion residues
- examination of the techniques most relevant to address those key issues
- identification of the best environmental performance levels, on the basis of the available data in the European Union and worldwide
- examination of the conditions under which these performance levels were achieved; such as costs, cross-media effects, main driving forces involved in the implementation of this techniques
- selection of the best available techniques (BAT) and the associated emission and/or consumption levels for this sector in a general sense all according to Article 2(11) and Annex IV of the Directive.

Expert judgement by the European IPPC Bureau and the relevant Technical Working Group (TWG) has played a key role in each of these steps and in the way in which the information is presented here.

On the basis of this assessment, techniques, and as far as possible emission and consumption levels associated with the use of BAT, are presented in this section that are considered to be appropriate to the sector as a whole and in many cases reflect current performance of some installations within the sector. Where emission or consumption levels ‘associated with best available techniques’ are presented, this is to be understood as meaning that those levels represent the environmental performance that could be anticipated as a result of the application, in this sector, of the techniques described, bearing in mind the balance of costs and advantages inherent within the definition of BAT. However, they are neither emission nor consumption limit values and should not be understood as such. In some cases, it may be technically possible to achieve better emission or consumption levels but due to the costs involved or cross-media considerations, they are not considered to be appropriate as BAT for the sector as a whole. However, such levels may be considered to be justified in more specific cases where there are special driving forces.

The emission and consumption levels associated with the use of BAT have to be seen together with any specified reference conditions (e.g. averaging periods).

The concept of ‘levels associated with BAT’ described above is to be distinguished from the term ‘achievable level’ used elsewhere in this document. Where a level is described as ‘achievable’ using a particular technique or combination of techniques, this should be understood to mean that the level may be expected to be achieved over a substantial period of time in a well maintained and operated installation or process using those techniques.

Where available, data concerning costs have been given together with the description of the techniques presented in the previous sections. These give a rough indication about the magnitude of costs involved. However, the actual cost of applying a technique will depend strongly on the specific situation regarding, for example, taxes, fees, and the technical characteristics of the installation concerned. It is not possible to evaluate such site-specific factors fully in this document. In the absence of data concerning costs, conclusions on economic viability of techniques are drawn from observations on existing installations.

It is intended that the general BAT in this section are a reference point against which to judge the current performance of an existing installation or to judge a proposal for a new installation. In this way they will assist in the determination of appropriate ‘BAT-based’ conditions for the installation or in the establishment of general binding rules under Article 9(8). It is foreseen that new installations can be designed to perform at, or even better than, the general BAT levels presented here. It is also considered that existing installations could move towards the general BAT levels or do better, subject to the technical and economic applicability of the techniques in each case.

While the BREFs do not set legally binding standards, they are meant to give information for the guidance of industry, Member States and the public on achievable emission and consumption levels when using specified techniques. The appropriate limit values for any specific case will need to be determined taking into account the objectives of the IPPC Directive and the local considerations.

To avoid duplication throughout this document, refer to BAT on Environmental Management System (EMS) in Section 3.15.1.

7.5.1 Supply and handling of gaseous fuels and additives

BAT in preventing releases related to the supply and handling of gaseous fuels, but also for storage and handling of additives such as ammonia etc. are summarised in Table 7.34.

Material	Environmental effect	BAT
Natural gas	Fugitive emissions	• using fuel gas leak detection systems and alarms.
	Efficient use of natural resources	• using expansion turbines to recover the energy content of the pressurised fuel gases • preheating the fuel gas by using waste heat from the boiler or gas turbine
Pure liquified ammonia (if used)	Health and safety risk according to ammonia	• for handling and storage of pure liquified ammonia, pressure reservoirs for pure liquified ammonia >100 m^3 should be constructed as double wall and should be located subterraneously; reservoirs of 100 m^3 and smaller should be manufactured including annealling process • from a safety point of view, the use of an ammonia-water solution is less risky than the storage and handling of pure liquefied ammonia.

Table 7.34: BAT for the supply and handling of gaseous fuels

7.5.2 Thermal efficiency of gas-fired combustion plants

To reduce greenhouse gases, in particular releases of CO_2 from gas-fired combustion plants such as gas turbines, gas engines and gas-fired boilers, the best available options from today’s point of view are techniques and operational measures to increase the thermal efficiency of the plant. Secondary measures, i.e. CO_2 capture and disposal as described in Annex 10.2 of this document, are at a very early stage of development. These emerging techniques might be available in the future, but they cannot yet be considered as BAT.

The energy efficiency has been considered as heat rate (fuel input energy/energy output at power plant border) and as power plant efficiency, which here is the inverse of heat rate, i.e. the percentage of produced energy/fuel input energy. The fuel energy is measured as the lower heating value.

For gas-fired combustion plants, the application of gas turbine combined cycles and the co-generation of heat and power (CHP) are technically the most efficient means of increasing the energy efficiency (fuel utilisation) of an energy supply system. A combined cycle operation and co-generation of heat and power is, therefore, to be considered as the first BAT option, i.e. whenever the local heat demand is great enough to warrant the construction of such a system. The use of an advanced computerised control system in order to achieve a high boiler performance with increased combustion conditions that support the reduction of emissions are also considered as BAT.

Improvement of the efficiency can also be obtained by preheating the natural gas, before its supply to the combustion chambers or burners. The heat can be obtained from low temperature sources, such as the exhaust gases from cooling from other regenerative processes.

Gas engine driven power plants are suited for both decentralised heat and power production (CHP) as well as for bigger base load applications. The BAT associated total efficiencies are up to 60 – 70 % in low pressure steam generation. With supplementary firing (i.e. when the oxygen content of the engine flue-gas acts as the main 'combustion air' in the burner) a large amount of low pressure or high pressure steam can be generated in an efficient way, In hot water production (with outlet temperatures typically in range of 80 – 120 ºC), a total efficiency (fuel utilisation) of up to 90 % in gas fuel mode can be seen as BAT, although highly depending on the portion of the engine cooling water energy recovered in the application. Hot water of up to 200 ºC can, of course, be produced by utilising the energy in the flue-gas and part of the engine cooling energy. Another advantage is the high thermal efficiency (i.e. low fuel consumption, and consequently low specific CO_2 emissions) of the engines. The BAT electrical efficiency (at alternator terminals) ranges from about 40 to 45 % (depending on the engine size) and is calculated on the lower heating value of the fuel.

For existing plants, a number of retrofit and repowering techniques can be applied to improve the thermal efficiency. The technical measures described in Section 2.7.8 should be taken into account as part of BAT options to improve the efficiency of existing plants. By applying the techniques and the measures listed in Section 7.4.2, to improve the thermal efficiency such as double reheat, and using the most advanced high temperature materials for gas turbines and boilers, energy efficiencies associated with the use of BAT can be achieved as summarised in Table 7.35.

In addition, the following measures also needs to be taken into consideration to increase the efficiency:

- combustion: minimising the heat loss due to unburned gases
- the highest possible pressure and temperature of the working medium gas or steam
- the highest possible pressure drop in the low pressure end of the steam turbine through the lowest possible temperature of the cooling water (fresh water cooling) for boilers and CCGT plants
- minimising the heat loss through the flue-gas (utilisation of residual heat or district heating)
- minimising the heat loss through conduction and radiation with isolation
- minimising the internal energy consumption by taking appropriate measures, e.g. scorification of the evaporator, greater efficiency of the feed water pump, etc.)
- preheating the fuel gas and or the boiler feed water with steam
- improved blade geometry of the turbines.

There was a split view from industry about the efficiency measures applied to CCGT plants, because the proposed measures will only have a marginal improvement of the total combined cycle efficiency. It should be noted that improvements of the gas turbine efficiency may result in a decrease of efficiency of the steam cycle. Therefore, the improvement of efficiency of the total cycle will be less than the improvement of the efficiency of the gas turbine only. Based on the above given rationale, industry is of the opinion that the proposed measures shall not be incorporated in the final draft of the BREF LCP.

Plant type	Electrical efficiency (%)		Fuel utilisation (%)	Remarks
	New plants	Existing plants	New and existing plants	
Gas turbine				
Gas turbine	36 – 40	32 – 35	-	
Gas engine				
Gas engine	38 – 45		-	
Gas engine with HRSG in CHP mode	>38	>35	75 – 85	The wide range of energy efficiency in CHP plants is very much dependent upon the specific situation and the local demand of electricity and heat
Gas–fired boiler				
Gas–fired boiler	40 – 42	38 – 40		
CCGT				
Combined cycle with or without supplementary firing (HRSG) for electricity generation only	54 – 58	50 – 54	-	
Combined cycle without supplementary firing (HRSG) in CHP mode	<38	<35	75 – 85	The wide range of the electrical and energy efficiency of CHP plants very much depends on the specific local demand for electricity and heat. By operating the CCGT in the CHP mode, the energy efficiency includes the amount of the electrical efficiency and should always be seen together to achieve the best overall exergetic efficiency.
Combined cycle with supplementary firing in CHP mode	<40	<35	75 – 85	

Table 7.35: Efficiency of gas-fired combustion plants associated to the use of BAT (based on ISO conditions)

It should be borne in mind that these BAT levels are not achievable in all operation conditions. The energy efficiency is at its best at the design point of the plant. The actual energy efficiencies throughout the operational period of the plants may also be lower due to changes, for instance changes in the load during the operation, quality of the fuel, etc. The energy efficiency also depends on the cooling system of the power plant, and on the energy consumption of the flue-gas cleaning system. It should also be recognised that high efficiency gas turbine systems may generate problems such as vibration and higher short term NO_X emissions.

7.5.3 Dust and SO_2 emissions from gas fired combustion plants

For gas-fired combustion plants using natural gas as a fuel, emissions of dust and SO_2 are very low. The emission levels of dust by using natural gas as a fuel are normally well below 5 mg/Nm^3 and SO_2 emissions are well below 10 mg/Nm^3 (15 % O_2), without any additional technical measures being applied.

If other industrial gases are used as a fuel such as refinery gas or blast furnace gas, pre treatment gas cleaning measures (such as fabric filters) needs to be applied and considered as BAT, in order to reduce the dust content and the amount of SO_2 in the flue-gas, which may otherwise damage the gas turbines or engines. As mentioned in the Refinery BREF, BAT is to limit the H_2S content of the refinery gas to 20 – 150 mg/Nm^3 leading to an emission of 5 – 20 mg of SO_2/Nm^3. Such gas do not create particulate emissions. In the case of natural gas refineries, also refer to the Mineral Oil and Gas Refinery BREF.

7.5.4 NO_X and CO emissions from gas-fired combustion plants

In general, for gas turbines, gas engines and gas fired boilers, reduction of nitrogen oxides (NO_X) is considered to be BAT. The nitrogen compounds of interest are nitric oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as NO_X.

For new gas turbines, dry low NO_X premix burners (DLN) are BAT. Most existing gas turbines can be converted to the dry low NO_X premix burner (DLN) technique, but sometimes the use of water and steam injection can be a better solution. This needs to be decided case by case.

Several gas turbine and gas engines operating in Europe, Japan and the US have also applied SCR to reduce the emissions of NO_X. Beside the dry low NO_X premix burner technique (DLN) and the injection of water and steam, SCR is also considered to be part of the BAT conclusion. For new gas turbines, the DLN burners can be seen as the standard technique so that the application of an additional SCR system is, in general, not necessary. For further reduction of NO_X, SCR can be considered where local air quality standards request a further reduction of NO_X emissions compared to the levels given in Table 7.37 (e.g. operation in densely populated urban areas). In Table 7.37 emergency machinery has not be taken into account.

For existing gas turbines, water and steam injection or conversion to the DLN technique is BAT. Gas turbines of unchanged combustion design, but with higher inlet temperatures, have higher efficiencies and higher NO_X values. In this context, it should be noted that with a higher efficiency the specific NO_X emission per kWh are still lower.

SCR retrofitting is technically feasible, but not economical for existing CCGT plants if the required space in the HRSG was not foreseen in the project and is therefore not available.

A split view was declared by industry saying that in the case of combined cycles, the HRSG has to be modified, which means dismantled and retrofitted to enable the incorporation of an SCR. This will increase the already high investments of SCR. Furthermore, the operation and maintenance costs of an SCR are relatively high, therefore, SCR is not cost effective for existing combined cycles. Industry also declared that, in the case of simple cycle gas turbines, SCR is not cost effective, because a) the gases have to be cooled down. This requires an additional cooler to reduce the gas temperature to a level to enable the SCR to operate. This cooler will increase the already high investments and operational costs, and b) simple cycle gas turbines in Europe are peak load plants, which run in emergency cases only. The high investment, operation and maintenance costs make the implementation of an SCR in a gas turbine economically unviable.

For gas-fired stationary engine plants, the lean-burn approach is BAT analogous to the dry low NO_X technique used in gas turbines. This is an inbuilt method and no extra reagents or wate need to be supplied to the site for NO_X reduction. Because gas engines are sometimes equipped with an SCR, these techniques can also be considered as part of BAT. To reduce the CO emissions, the application of oxidation catalysts is BAT with the associated emission levels for natural gas firing mentioned in Table 7.36. In the case of buring other gasous fuels such as biogas or landfill gases, the CO emission can be higher due to the specific fuel used

The NMVOC emissions from spark ignited lean burn gas (SG) engines and dual fuel (DF) engines in gas mode depend on the composition of natural gas. NMVOC secondary emission reduction techniques might, in some cases, be needed and an oxidation catalyst for simultaneous CO and NMVOC reduction can be applied. CO values kept below 100 mg/Nm^3 (15 % O_2) and formaldehyde values below 23 mg/Nm^3 (15 % O_2) are considered as BAT for a gas-fired engine equipped with an oxidation catalyst.

BAT for the minimisation of CO emissions is complete combustion, which goes along with good furnace design, the use of high performance monitoring and process control techniques and maintenance of the combustion system. Besides the combustion conditions, a well optimised system to reduce emissions of NO_X will also keep the CO levels below 100 mg/Nm^3. In addition, the application of an oxidation catalyst for CO can be seen as BAT when it is operated in densely populated urban areas.

The BAT conclusion for the prevention and control of NO_X and CO emissions and the associated emission levels are summarised in Table 7.36 and Table 7.37. Flue-gases from gas turbines and gas engines typically contain about 11 – 16 vol-% O_2 and, therefore, the emission levels associated with the use of BAT for turbines and engines have been based on an O_2 level of 15 vol-%, and standard conditions as the reference point. For gas-fired boilers, 3 vol-% O_2 is usually used as a reference level. The BAT associated emission levels are based on a daily average, standard conditions and represents a typical load situation. For peak load, start up and shut down periods as well as for operational problems of the flue-gas cleaning systems, short-term peak values, which could be higher have to be regarded.

Plant type	**Emission level associated with BAT (mg/Nm^3)**		**O_2 level (%)**	**BAT options to reach these levels**	**Monitoring**
	NO_x	**CO**			
Gas turbines					
New gas turbines	20 - 50	5 – 100	15	Dry low-NO_x premix burners (standard equipment for new gas turbines) or SCR	Continuous
DLN for existing gas turbines	20 - 75	5 - 100	15	Dry low-NO_x premix burners as retrofitting packages if available	Continuous
Existing gas turbines	50 – 90$^{(1)}$	30 - 100	15	Water and steam injection or SCR	Continuous
Gas engines					
New gas engines	20 – 75$^{(2)}$	30 – 100$^{(3)}$	15	Lean burn concept low-NO_x tuned and oxidation catalyst for CO or SCR and oxidation catalyst for CO	Continuous $^{(4)}$
New gas engine with HRSG in CHP mode	20 – 75$^{(2)}$	30 – 100$^{(3)}$	15	Lean burn concept low-NO_x tuned and oxidation catalyst for CO or SCR and oxidation catalyst for CO	Continuous $^{(4)}$
Existing gas engines	20 – 100 $^{(2)}$	30 – 100$^{(3)}$	15	Low-NO_x tuned	Continuous $^{(4)}$

1	Industry and one Member State claimed that the amount of water or steam that can be injected in an existing gas turbine is limited. Injection high amounts of water or steam may lead to damage of gas turbine components. Therefore, they claimed that the range needs to be substituted by 80 – 120 mg/Nm^3.
2	Industry claimed that these ranges are not according the BAT approach. The reason given was that the range given as BAT is the same as the one given by the American LAER approach (lowest achievable emission rate). Industry proposed an environmental quality driven approach taking the surrounding (urban/other areas) into account. That means that small plants situated in rural areas shall have leaner BAT levels than large plants in city areas. Industry claimed that levels of 190 mg/Nm^3 (15 % O_2) in gas mode represented the overall emission optimum considering the lowest possible fuel consumption and unburned gaseous emission of CO, VOC etc. for spark-ignited (SG) and dual fuel engines (DF) in gas mode.
3	Industry mentioned that due to technical reasons (fuel composition impact), CO should be at a level of 110 – 380 mg/Nm^3 (15 % O_2) in order to represent BAT.
	Another Industry representative claimed that the ranges should be changed to:
2	90 – 190 mg/Nm^3
3	100 mg/Nm^3 because the emission levels associated with BAT for gas engines are only applicable for burning natural gas and not for renewable gases like landfill gas, biogas or purification gas. Moreover, they claimed that such levels would create disadvantages for competitiveness in the market for such gases.
4	One Industry representative proposed charging to discontinuous monitoring because continuous engine emission monitoring is not common practice for stationary internal combustion engines.

Table 7.36: BAT for the reduction of NO_X and CO emissions from some gas-fired combustion plants

Plant type	Emission level associated with BAT (mg/Nm^3)		O_2 level (%)	BAT options to reach these levels	Monitoring
	NO_x	CO			
Gas–fired boilers					
New gas–fired boilers	50 – 100(1)	30 – 100	3	Low-NO_x burners or SCR or SNCR	Continuous
Existing gas–fired boiler	50 – 100(2)	30 – 100	3	Low-NO_x burners or SCR or SNCR	Continuous
CCGT					
New CCGT without supplementary firing (HRSG)	20 – 50	5 – 100	15	Dry low-NO_x premix burners or SCR	Continuous
Existing CCGT without supplementary firing (HRSG)	20 – 90(3)	5 – 100(5)	15	Dry low-NO_x premix burners or water and steam injection or SCR if the required space has already been forseen in the HRSG	Continuous
New CCGT with supplementary firing	20 - 50	30 – 100	Plant spec.	Dry low-NO_x premix burners and low-NO_x burners for the boiler part or SCR or SNCR	Continuous
Existing CCGT with supplementary firing	20 – 90(4)	30 – 100 (5	Plant spec.	Dry low-NO_x premix burners or water and steam injection and low-NO_x burners for the boiler part or SCR if the required space has already been foreseen in the HRSG or SNCR	Continuous

	Industry claimed that the ranges need to be changed to:
1,2	upper end to 120 mg/Nm^3
3	80 – 120 mg/Nm^3 because gas fired boilers depend on the firing temperature, the type of burners, the size of the boiler, the heating surfaces, the air temperature and the load factor of the power plant. In case the boiler is equipped with flue-gas recycling it is possible to decrease the NO_x emission to a level of 100 mg/Nm^3. However, retrofitting an existing boiler with flue-gas recycling will require high (not cost effective) investment costs.
2	One Member State proposed that for existing gas fired boilers, which have been converted recently from heavy fuel oil to burn natural gas, after full modification with primary measures to reduce NO_X (flue-gas recirculation, fuel and air staging), the BAT achievable emission levels should be modified to 10 – 150 mg/Nm^3.
4	Industry mentioned that due to the large wall burners which are used for supplementary firing of the HRSG the NO_x emission of the gas turbine may increase in 10 – 20 mg/Nm^3. This increase is caused by local high temperatures of these duct burners. Therefore, the level associated with BAT in the case of supplementary firing should be 80 – 140 mg/Nm^3.
3,4	One Member State claimed that the upper BAT levels for CCGT plants >50 MW cannot be over 80 mg/Nm^3 and for plants over 200 MW the upper BAT level should be below 35 mg/Nm^3 because these levels have already been fixed as ELVs in the Member State in question.
5	One Member State claimed that the upper levels of CO for CCGT plants >50 MW cannot be over 35 mg/Nm^3 because this level has already been fixed as ELV in the Member State in question.

Table 7.37: BAT for the reduction of NO_X and CO emissions from some gas-fired combustion plants

For refinery gas refer to Mineral Oil and Gas Refinery BREF. In the case of Natural gas refineries, also refer to the Mineral Oil and Gas Refinery BREF.

7.5.4.1 Water pollution

Different waste water streams (see Chapter 1) are generated by gas-fired combustion plants. To reduce emissions to water and to avoid water contamination, all measures that have been presented in Section 7.4.4 are considered to be BAT.

Small amounts of oil contaminated (washing) water cannot be prevented from occurring occasionally at a power plant. Oil separation wells are, in general, sufficient to avoid any environmental damage.

The other techniques described for waste water treatment in Chapter 3 can, in general, also be considered as BAT for this sector.

7.5.4.2 Combustion residues

A lot of attention has already been paid by industry to the utilisation of combustion residues and by-products instead of depositing them in landfills. Utilisation and re-use is, therefore, the best available option.

7.5.5 BAT for combustion installations operated on offshore platforms

The conclusions on BAT for the offshore sector have taken into account that combustion installations operated offshore are used in a more complex and potentially hazardous environment than in onshore power stations. In addition, space and weight are at a premium, leading to a much higher equipment density than is common in onshore applications. In addition, any undue complexity is generally avoided offshore, because of weight, space, safety and operability factors. Therefore, techniques such as water and steam injection, which require a high quality water treatment plant or SCR with additional storage of ammonia, have not been considered as BAT for offshore applications to reduce NO_X emissions.

In general, for new gas turbines operated on offshore platforms, the reduction of nitrogen oxides (NO_X) by using primary measures such as dry low NO_X premix burners (DLN) is considered to be BAT as far as this technique is available. The associated emission level of NO_X by using the dry low NO_X premix burners (DLN) for gas turbines is less than 50 mg/Nm^3. As the flame stability needs to be maintained over the full range of operating conditions, it may not be practical to maintain staged combustion at low rates, such as at start-up and part load operation. The formation of NO_X is not reduced during such periods and hence the occurrence and duration of these periods should be minimised.

Retrofitting of existing offshore gas turbines is much more expensive compared to land-based turbines due to the modification work costs. Retrofitting the DLN technology in existing offshore gas turbines is limited due to higher costs and a restriction of space within the turbine package for new fuel manifolds or combustion chambers. For aeroderivative turbines often used offshore, retrofitting to DLN is generally much more complex than for an industrial turbines. The whole combustion section has to be replaced, and due to the larger outer diameter of the DLN combustion section, the gas turbine centreline is shifted. The applicability of retrofitting the DLN technology will, therefore, differ from platform to platform due to the type of turbine, the complexity, the age, etc.The BAT level for existing installations have to be determined on a case by case basis.

To reduce the environmental impact of offshore gas turbines, the following measures are part of the BAT conclusion:

- for new installations, selecting turbines which can achieve both a high thermal efficiency and a low emissions spectrum
- using dual fuel turbines only where operationally necessary
- minimising 'spinning reserve'
- providing a fuel gas supply from a point in the topside oil and gas process which offers a minimum range of fuel gas combustion parameters, e.g. calorific value, etc.
- providing a fuel gas supply from a point in the topside oil and gas process which offers minimum concentrations of sulphurous compounds – to minimise SO_2 formation
- operating multiple generator or compressor sets at load points which minimise pollution
- optimising the maintenance and refurbishment programmes
- optimise and maintain inlet and exhaust systems in a way that keeps the pressure losses as low as possible
- optimise the process in order to minimise the mechanical power requirements and pollution
- utilisation of gas turbine exhaust heat for platform heating purposes.

Modern 'diesel' engines are available with high pressure fuel injection controlled by electronics. Additionally, optimised combustion chambers and portings have been developed. This technology can result in increased fuel economy, reduced NO_X and other gaseous emissions and reduced smoke, particularly during acceleration and start-up. Where available, it represents the BAT for minimising emissions such as SO_2 and NO_X.

To reduce the environmental impact of offshore engines, the following measures are part of the BAT conclusion:

- for new engines, selecting diesels which achieve both high thermal efficiency and a low emissions spectrum
- where process gas is used as fuel, providing a supply from a point in the topside process which will offer minimum emissions of, e.g. SO_2. For liquid distillate fuels, preference should be given to low sulphur types
- for larger diesels, considering gas fuelling with a ' torch oil' ignition charge
- optimising injection timing
- operating multiple generator or compressor sets at load points which minimise pollution
- optimising maintenance and refurbishment programmes.

Low NO_X burners are available for many gas fired heaters, boilers and furnaces. This represents BAT for minimising NO_X, although the effect and trade off with fuel consumption must be evaluated.

Other measures to increase the energy efficiency of offshore installations and thus to reduce the emissions per unit of energy used, such as the application of CHP plants, are part of the BAT conclusion. Techniques that assist the optimised use of equipment such as those based on operational monitoring approaches are BAT. In this case, the gas turbine is 'baselined', and predictive software is used to calculate the emissions. This software may also be used to indicate to the offshore operation personnel the optimum operating point(s) for single or multiple turbine installations. Such systems do not remove the need for emission compliance checks, but may assist personnel to operate the overall combustion system more efficiently.

Other techniques, like PEMS (parametric emission monitoring system) are BAT for both new and existing combustion installations operating offshore. The system offers cost effective solutions for emission monitoring and calculating the emissions. In addition it can also be used to optimise the combustion processes and maintenance schedule of gas turbines.

Power integration of multiple fields are BAT and, where applicable, needs to be decided on a platform by platform and field by field basis.

7.6 Emerging techniques for the combustion of gaseous fuels

7.6.1 Catalytic combustion

Catalytic combustion is a technology that combusts fuel flamelessly. This process releases the same amount of energy as flame-based combustion systems but at a lower peak temperature. Importantly, this lower temperature is below the threshold at which NO_X is formed. This is achieved by combustion on a palladium-based catalytic surface. As the temperature range in which the catalyst is active is limited both at the low end (not enough activity) and at the high end (degradation), the combustion process consists of three stages:

- **pre-combustion:** an integrated pre-burner raises the temperature of the incoming gas/air mixture to the required value for the catalyst to become active. This applies mainly in low load situations. Typically only a small portion of the fuel is used in the pre-burner
- **catalytic combustion:** catalysed combustion takes places at relatively low temperatures, thus inhibiting NO_X formation. Not all the fuel is burned here, as this would raise the temperature of the catalyst too much, thus degrading the catalyst
- **homogenous combustion:** the rest of the fuel is burned under lean fuel conditions. No flame instability occurs, as the inlet temperature of this zone is already fairly high because of the upstream catalytic combustion.

Catalytic combustor technology which is a very promising technology is just entering commercial service in the US. Information provided by manufacturers is based generally on 'demonstrated in practice' installations Catalytic combustion has been demonstrated only at pilot scale on a 1.5 MW_e gas turbine. Plans for application on a 170 MW_e gas turbine are being developed. NO_X levels of less than 10 mg/Nm^3 are expected with the use of this technique.

7.6.2 Steam cooling

Another advanced gas turbine development is the use of steam cooling instead of air cooling. Usually extracted air from the gas turbine compressor is used for the cooling of the turbine shaft and blading. The amount of cooling air is up to 20 – 25 % of the compressor airflow. The extracted air is not available for the combustion process and also loses pressure when flowing through the narrow channels in the turbine blades, which causes efficiency losses in the gas turbine process. By using steam instead of compressed air, these disadvantages are eliminated. Steam cooling is more efficient than air cooling.

In the turbines mentioned above, a closed steam cooling system is applied. Steam cools the hot components such as turbine blades, vanes or transition pieces. The used steam is not mixed with the main gas flow through the gas turbine (as in an open system), but is routed back to the steam system, where it can be expanded as reheat steam through the steam turbine. The steam for the cooling is extracted from the exhaust section of the high pressure steam turbine. The steam is reheated to the reheat temperature and then mixed with the reheated steam from the heat recovery steam generator (HRSG), and led to the intermediate pressure section of the steam turbine for further expansion. The cooling steam does not affect the main flow through the gas turbine and, in principle, there should be no consumption of water.

By applying steam cooling, the turbine inlet temperature is increased without any relevant increase in combustion temperature. As a result, a higher efficiency is obtained without an increase in NO_X emissions. Cooling by steam instead of air strongly reduces the air bled from the compressor, the compressed air and thus the power consumption of the compressor. This results in a higher gas turbine efficiency too.

With this new cooling technology, a combined cycle efficiency improvement of two percentage points can be reached and an efficiency of 60 % can be expected.

7.6.3 Further development potentials

Some further important potential improvements include:

- improving the materials and cooling to enable turbine inlet temperatures of 1500 °C for frame type gas turbines and 1700 °C for aeroderivative gas turbines to be achieved
- reducing the amount of compressed air used for the cooling medium
- cooling the blades with external cooling flow (water or steam)
- in the future, generally using single crystal blades
- improving the temperature profile at the turbine inlet. Without hot spots, the general temperature can be set just below the temperature limit given by the material [58, Eurelectric, 2001].

7.6.4 Recuperative options

There are several options to recuperate the exhaust gas heat into the gas turbine process. This section describes some of these features.

7.6.4.1 Intercooled recuperated gas turbine

A large part of the power that is generated by the turbine is required to drive the compressor. A way to improve the gas turbine efficiency is to reduce the compressor work by cooling the airflow through the compressor. The compressor power is proportional to the volume flow. Theoretically, cooling after each compressor stage will give the largest reduction of compressor work, however in practice only a restrictive number of cooling stages is feasible.

If the temperature of the gas turbine exhaust gas is higher than the outlet air temperature of the compressor, it is possible to transfer some of the heat from the exhaust gas to the compressor outlet air. This improves the gas turbine efficiency because less fuel is required to heat the gas to the desired turbine inlet temperature. This kind of recuperation can mainly be used for gas turbines with a moderate compression ratio or for gas turbines with intercooled compressors.

Designs incorporating the application of both compressor intercooling and recuperation as described can reach an efficiency of 54 %, calculated at a turbine inlet temperature of 1200 °C [58, Eurelectric, 2001].

7.6.4.2 HAT cycle

In the humidified air turbine (HAT) cycle, humidification of the compressed air after the air compressor allows the compressed air temperature to be decreased. In the HAT cycle all the air is saturated with water vapour utilising waste heat from compressor intercoolers and from the gas turbine exhaust. With this cycle, a higher possible amount of regenerated heat from the exhaust gases can be used than with an intercooled and recuperation process. The difficulty with this cycle is that standard gas turbines cannot be used for the process, as the mass flow through the turbine is increased too much through the saturation of all the compressor air with water. The high content of water vapour in the combustion air might also create problems for the burners. Although with this process, a lower compressor ratio results in a higher efficiency. An efficiency of about 53 % is feasible for a turbine inlet temperature of 1200 °C [58, Eurelectric, 2001].

7.6.4.3 TOPHAT process

In this process, the air is humidified at the compressor inlet by the injection of water. Theoretically, an injection is also possible after each stage of the compressor. This improves the gas turbine efficiency by up to 55 %, calculated for an inlet turbine temperature of 1200 °C, which is the highest value for the efficiency of the cycles described before. A further improvement of the TOPHAT cycle is possible by injecting water between the different compressor stages. Therefore, the water needs to be heated and pressurised. For the heating of the injection water, heat from the exhaust gases is used [58, Eurelectric, 2001].

7.6.4.4 CHAT cycle

The Cascade Humidified Advanced Turbine (CHAT) cycle makes use of a low pressure and a high pressure gas turbine on separate shafts and composed from existing compressors and turbines to allow for the increased mass flow through the turbines due to saturation with water. The cycle includes intercooling between the separate compressors, as well as reheating of the flue-gas between the separate turbines [58, Eurelectric, 2001].

8 CO-COMBUSTION OF WASTE AND RECOVERED FUEL

Besides combustion in specially designed and operated waste incineration plants which are regulated according to the Directive 2000/76/EC, waste, such as contaminated biomass and certain waste fractions may also be co-combusted in regular combustion installations such as power plants, which are partly regulated by the waste incineration Directive and partly by the LCP Directive in the form of the implementation into the specific national law. The co-combustion of ‘clean’ biomass as defined in the LCP Directive is descrbed in Chapter 4 of this document. In this sense, reference is also given to the CEN work on ‘solid recovered fuels’ which is well in progress. This chapter mainly focuses on the effects of the co-combustion of certain waste materials in large combustion plants (e.g. coal- or lignite-fired, peat-, wood-, coal-fired fluidised bed boilers). Currently, three main factors are driving the idea of the co-combustion of waste in large combustion plants:

- legislation is discouraging the disposal of waste and biomass waste with high calorific values (e.g. >6000 kJ/kg dry substance). Therefore, there is a need to establish alternative ways to treat the respective waste fractions. Co-combustion is one option among others (including e.g. mono-incineration, mechanical-biological treatment)
- under the requirement of the Kyoto protocol, greenhouse gas emissions have to be reduced worldwide. The co-combustion of biomass waste (and with certain restrictions also some waste fractions) is one option to reduce greenhouse gas emissions
- liberalisation of the energy market is intensifying economic pressure on energy producers. The co-combustion of waste and biomass waste will open up a new business for them, which will make the operation of a large combustion plant economically more attractive.

In this chapter, the term ‘**secondary fuel (SF)’** includes all waste types that have a sufficiently high calorific value to be used as a fuel (secondary fuel) and that may be co-combusted in large combustion plants together with conventional fuels (typically coal, lignite, liquid fuels, etc.). It includes materials currently known in literature as waste, recovered fuel (REF), refuse derived fuel (RDF) or biomass waste derived fuel. It is not the intention here to enter into a discussion on the definition of these terms. More information can be found in CEN proposals. Also some of these materials can be classified as hazardous, as they may be contaminated with hazardous materials. The co-combustion of clean biomass follows the definition of biomass given in the EU Directive 2001/80/EC on large combustion plants and is dealt with in Chapter 5, where descriptions of the combustion of biomass and peat can be found. Key issues in the co-combustion of secondary fuels are:

- fuel quality and characteristics
- boiler design
- fuel handling and feeding
- slagging, or bed sintering (fluidised bed boiler)
- fouling of heat transfer surfaces
- hot corrosion
- effects on emission levels compared to the emissions that occur when only a conventional fuel is used
- ash properties, bottom ash removal
- storage of waste; utilisation and/or disposal options for solid waste/residues from co-combustion.

A large diversity of materials can be co-combusted in LCPs. Section 8.3 gives a list of secondary fuels currently co-combusted in LCP installations in the EU.

Within the scope of this chapter, it is assumed that secondary fuels are pretreated, which typically means that the combustible parts are separated from the non-combustible parts. In order to give a better understanding of this topic, reference is made to be the Waste BREFs. These documents contain issues such as the incineration or pretreatments of waste. In particular:

- Waste Treatment (WT): this BREF describes processes and techniques that deal with the transformation of waste in order for it to be used as a fuel in any combustion process (such as in large combustion plants, cement works, chemical works, iron-steel, etc.). These pretreatments are, e.g. sorting, crushing, preparation and so on
- Waste Incineration (WI): this BREF deals with incineration and covers similar installations as those covered by the Waste Incineration Directive.

8.1 Applied processes and techniques used in the co-combustion of secondary fuels in LCP

The use of secondary fuel in large combustion plants implies the use of certain processes and techniques. Techniques related to these activities are described in this section. Cross-references are made to other chapters and other BREFs where necessary.

8.1.1 Acceptance and pre-acceptance procedures

These systems and procedures are in place to ensure that secondary fuels (e.g. wastes) are subjected to appropriate technical appraisal to ensure its suitability for the proposed use of the secondary fuel. Health protection for staff and other persons – possibly in contact with waste derived fuels – has to be considered. Extensive information about these pre-acceptance and acceptance procedures can be found in the Waste Treatment BREF.

8.1.2 Unloading, storage and handling

The way secondary fuels are unloaded, stored or handled depends on the state of aggregation and the physical properties of the different materials.

Gaseous secondary fuels (**SF)** are normally transported to power plants through pipelines and directly fed to the burners, without storage. The types of techniques used for these materials are no different to those used for gaseous fuels (see Chapter 7).

Liquid SF can be supplied by ship, train, lorry or pipeline, depending on the availability of transport systems at the location where the secondary fuel is produced. Liquid secondary fuel can be stored in tanks on site, or directly fed into the boiler.

The storage and handling of **solid** secondary fuel depends strongly on the physical properties of the secondary fuel, for example:

- dried sludge (granulate) can be supplied by ship, train or lorry and is stored in silos or closed bunkers to avoid fugitive dust emissions Dried sludge should be combusted immediately due to its hygroscopic properties
- formation of methane in sludge silos or bunkers has to be controlled by regular air exchange. Air containing methane or odorous compounds should be used as combustion air. During times of boiler standstill, air exchange and suitable treatment of exhaust gas has to be guaranteed
- odorous sludge has to be transported and stored in silos or closed bunkers to prevent odour emissions
- wet sludge can be spread out over the coal in the coal yard, but the possible generation of odour emissions and dilution into the waste water treatment system have to be taken into account
- regarding special provisions for the storage and handling of biomass, reference is made to Section 5.1.1.

8.1.3 Pretreatment of secondary fuels

This section describes those processes (e.g. grinding, gasification, pyrolysis and pre-combustion) applied to prepare the fuel for combustion as a gaseous, liquid or pulverised solid fuel. This pretreatment is necessary to assure an adequate burnout in the boiler, due to the short residence time of the fuel in the furnace. The most direct method of the co-combustion of secondary fuel is mixing with the main fuel. The following pretreatment techniques are described in the following paragraphs:

1. milling
2. pre-combustion
3. drying (more information can be found in the WT BREF)
4. pyrolysis (more information can be found in the WI BREF)
5. gasification (more information can be found in the WI BREF)
6. methanisation (more information can be found in the WT BREF).

It is important to notice (see above list) that some of these pretreatment techniques are already described in the Waste Treatment and Waste incineration BREFs. For this reason, no further description is included in this section.

8.1.3.1 Milling

Milling is used to treat solid fuels to convert it to a size that is suitable to be used in the power plant. For example, in fluidised bed boilers the particle size is typically no larger than 100 mm and in pulverised fuel-fired boilers typically less than 75 µm. Information on the type of milling used with solid fuels has been included in Section 4.1.3.

8.1.3.2 Pre-combustion

Pre-combustion in an atmospheric fluidised bed (FBC) is an option for materials that cannot be combusted properly in pulverised coal-fired boilers. This especially concerns fuels that are difficult to pulverise, or fuels that contain pollutant ashes. As mentioned in previous chapters, fluidised bed combustion needs only a crushing or coarse grinding of the fuel. Pulverising is not required.

Flue-gases from FBC are not directed to the main boiler. The integration is on the water/steam side only. These systems are identical to the standalone systems described in Chapter 4 and Section 5.1.3.2. In this case, the ashes of the secondary fuel will not influence the quality of the pulverised coal ash.

8.1.3.3 Drying

Fuel that is too wet to be dried in a coal mill needs to be dried elsewhere (pretreated) before it is mixed with the main fuel. The drying of the wet secondary fuel can take place at the power station or at the location where the fuel is produced, recovered or collected. This depends strongly on the local infrastructure and the kind of secondary fuel. Drying of the fuel is based on physical and physico-chemical processes of mass and heat transport, resulting in evaporation of the moisture from the fuel. The heat required for the evaporation of the moisture can be supplied by convection, conduction or radiation. Since drying is not specific to large combustion plants, these processes are not elaborated further in this document. More information can be found in the Waste Treatment (WT) BREF.

Three type of dryers are available:

- convection dryers: there is direct contact between the heating medium and the product to be dried. Therefore, these dryers are also called direct dryers or adiabatic dryers. The moisture from the fuel is removed by the heating medium
- conduction dryers: there is no direct contact between the heating medium and the product. Heat transfer takes place through heating surfaces. Moisture is removed by the carrier gas, which is approximately 10 % of the quantity used in connective processes. Therefore conduction dryers may be preferred for dusty or odorous wastes
- radiant dryers: these are not applied for drying secondary fuels.

Typical examples of secondary fuels that may need to be dried are **sewage sludge** and **manure** (e.g. chicken litter), with moisture contents exceeding 50 %.

8.1.3.4 Pyrolysis

Pyrolysis is a thermo-chemical process, in which fuel at a high temperature, is converted in the absence of oxygen, into gaseous, liquid or solid products. Two types of pyrolysis processes exist:

- **fast pyrolysis processes**, in which the feedstock is rapidly heated to the process temperature, were developed for the production of pyrolysis oil or specific components from this oil
- **carbonisation processes**, in which the feedstock is heated slowly to the pyrolysis temperature, resulting in a relatively high solid production.

The solid product of this process (called char) contains a lot of carbon and can be treated as coal. The liquid and solid materials produced can be stored before co-combustion. Thus, these materials can be pretreated independently of the power plant operation. The gases produced are often used to supply the heat required for the endothermic conversion process.

Since pyrolysis is not specific to large combustion plants, these processes are not elaborated further in this document. More information can be found in the Waste Incineration (WI) BREF.

Pyrolysis is used in the co-combustion of secondary fuel in a pulverised coal- or lignite-fired power plant when it cannot be ground in a coal mill to the required dimensions.

An example power plant where pyrolysis has been applied, is the so-called ‘Contherm’ plant, which was developed for the co-combustion of refuse derived fuels (RDFs) in a coal-fired power plant with wet bottom boiler and a rated thermal input of 769 MW_{th}. The pyrolysis process is realised in two rotary kilns heated indirectly by gas or oil burners which heat the waste to about 550 °C without any addition of air. The pyrolysis gas is burned directly without cooling in the power plant. The pyrolysis residue is screened and the fine fraction, which contains the carbon, is fed to the coal mills. The RDF consists of sheared plastic waste from different sources, industrial waste and coarse reject from the paper industry. The size of the waste chips must not exceed 200 mm. About 7900 t/yr of recyclable metals will be extracted in the reprocessing plant. The power plant is equipped with an SCR and a wet FGD [98, DFIU, 2001].

8.1.3.5 Gasification

Some kinds of secondary fuel contain impurities such as chlorine, alkali, metals (e.g. aluminium, heavy metals) in such quantities that they require adequate cleaning before co-combustion in the boiler takes place. Gasification of these materials may be an attractive option. The gas produced by gasification can be burned directly in the LCP or can be cleaned before use in the LCP or gas turbine, but there are no currently functioning gas turbines operated with cleaned gasification gas.

A gasification method used to be applied in Austria but is not in operation anymore, where a CFB gasifier is used to produce a gas from biomass, waste and demolition wood. The gas, which also contained the solid particles of the gasification process, entered the boiler via a specially designed burner, which guaranteed rapid ignition, a stable flame, deep penetration into the coal flame and good mixing. Furthermore, it acted as a reburning fuel, thus decreasing NO_X emissions by converting NO_X to nitrogen. The thermal input of this plant was 10 MW. Approximately 15 – 20 % of the coal was replaced by biomass [64, UBA, 2000].

Figure 8.1 and Figure 8.2 give a schematic overview of a gasification plant in combination with a coal-fired boiler operated in Finland. In this power plant, the gas from the circulating fluidised bed gasifier is directly fed into the boiler without any further cooling or cleaning. The gasifier is no more than a thermo-mechanical mill for fuel preparation.

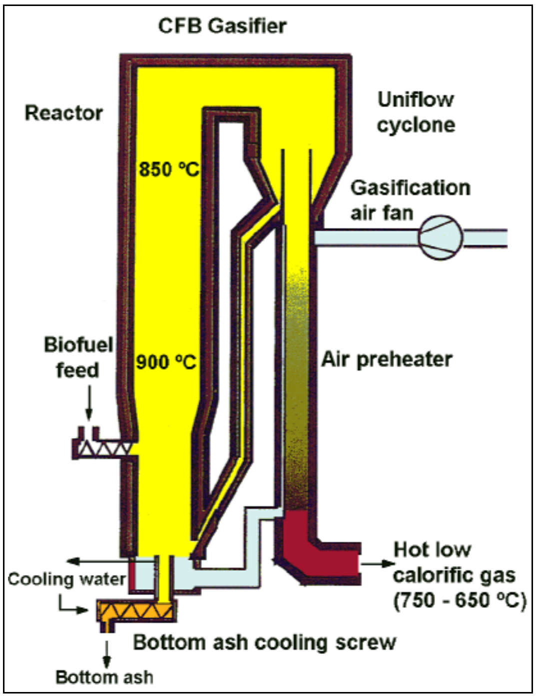


Figure 8.1: CFB gasifier connected with a coal-fired boiler
[153, Nieminen, et al., 1999]

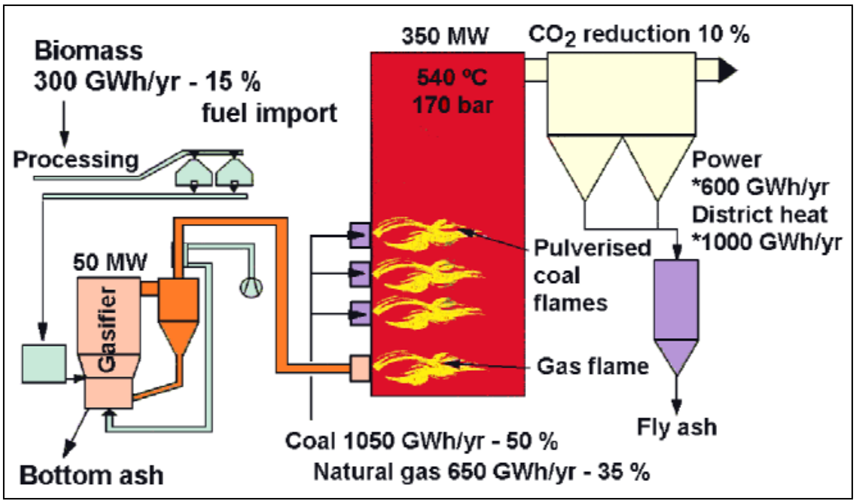


Figure 8.2: Flow sheet of a gasifier concept
[153, Nieminen, et al., 1999]

Secondary fuel (typically commercial and household based recovered fuels, forest residues and shredded tyres) are transported to the power plant in trucks and stored in separate receiving halls. The coarse fuel particles are crushed and the fine fractions are transported via conveyor belts into a storage silo near the gasifier. After homogenisation in this silo, the fuel mixture is fed to the gasifier. The circulating fluidised bed gasifier consists of an inside refractory-lined steel vessel, where fuel is gasified in a hot fluidised gas-solid particle suspension. At atmospheric pressure and at temperatures of about 850 °C the fuel mixture is converted to a combustible gas. In a cyclone downstream of the gasifier, the coarse particles in the gas are separated and recycled to the gasifier. The gas produced flows from this cyclone to the air preheater, in which gasification air is preheated to temperatures of about 650 °C. The hot gas is burned in the coal-fired main boiler of the plant, substituting up to approximately 30 % of the coal. The gasifier has been in successful operation since January 1998 [58, Eurelectric, 2001].

Another example of gasification in combination with a coal-fired boiler has been constructed in the Netherlands. As shown in Figure 8.3, the gas produced is cooled and cleaned before introduction into the coal-fired boiler. The gasification plant is designed for demolition wood. From a technical point of view, other waste streams or recovered fuels can be gasified. The capacity of the gasification plant is 150000 tonnes/year of demolition wood, which equates to a substitution of approximately 5 % of the coal.

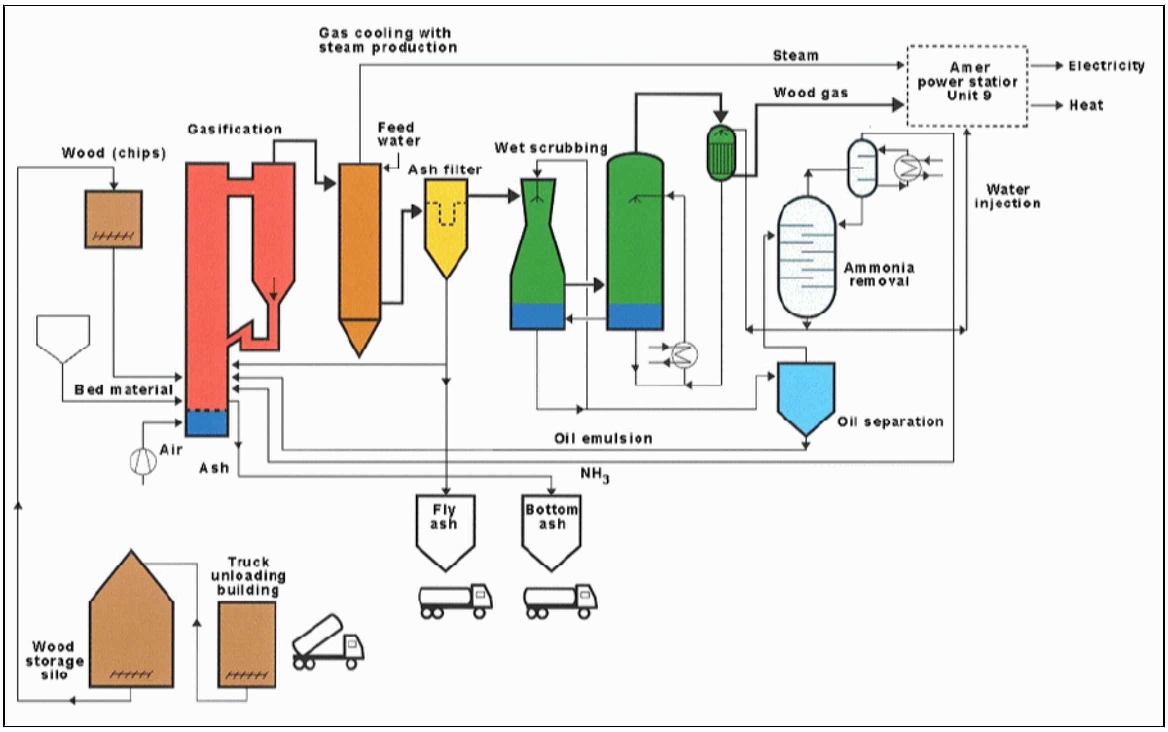


Figure 8.3: Wood gasification with gas cleaning
[58, Eurelectric, 2001]

Wood chips are supplied to the above power station by ship and truck and stored in a bunker. From this bunker the wood is transported to a feed vessel from which the gasifier is fed. The atmospheric circulating fluidised bed gasifier (AFBG) operates at temperatures of 850 to 950 °C. The bed consists of sand mixed with limestone or dolomite. The gas from the gasifier is cooled in a gas cooler in which superheated medium pressure steam is produced. Fly ash is separated from the gas in a filter and can be partly recycled to the gasifier. The dust-free gas is supplied to the existing boiler via special wood gas burners [58, Eurelectric, 2001].

Since gasification is not specific to large combustion plants, these processes are not elaborated further in this document. More information can be found in the Waste Incineration BREF.

8.1.3.6 Methanisation

Secondary fuel can also be methanised by anaerobic digestion. These techniques transform an organic matter to gas (mainly methane) that can be later used in the LCP. Since methanisation is not specific to LCPs, these processes are not elaborated further in this document. More information can be found in the Waste Treatments BREF.

8.1.4 Techniques to introduce secondary fuels into the combustion process

When secondary fuels (SFs) are used as fuel in co-combustion process, certain procedures need to be applied to introduce such material into the combustion process. Several techniques can be applied to achieve a proper mixing, for example, SFs can be mixed together with the main fuel during handling and burned together. However, other techniques exist where the SFs are introduced into the combustion chamber through different feeding lines from the main fuel. All these types of techniques are described in this section.

8.1.4.1 Mixing with the main fuel

The easiest way to introduce secondary fuel into the combustion process is by mixing it with the main fuel. In a coal- or lignite-fired boiler, the following locations for fuel mixing are possible:

- on the coal conveyor belt
- in the coal bunker
- in the coal feeder
- at the coal mill
- on the pulverised coal lines.

In the first three situations, the secondary fuel is spread over the main fuel (coal). In this way an adequate mixing of the fuel streams occurs. This results in a grinding of the secondary fuels together with the main fuel in the coal mill as shown in Figure 8.4.

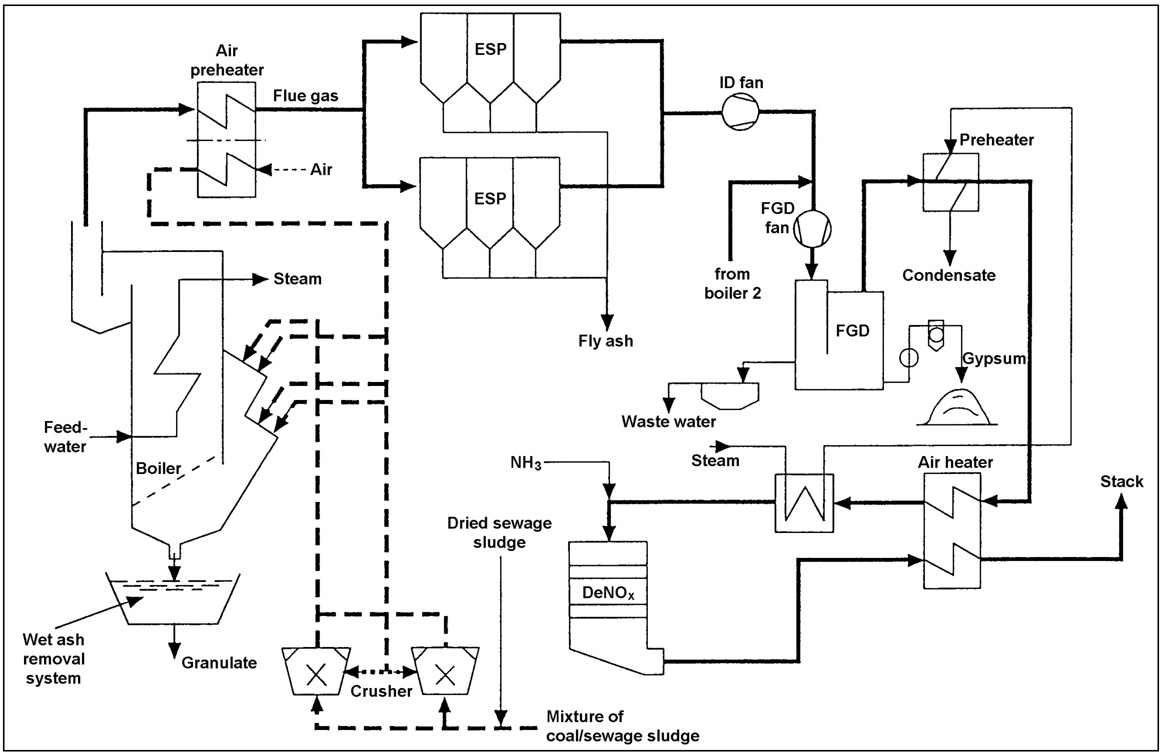


Figure 8.4: Co-combustion of coal and sewage sludge
[112, Ekmann, et al., 1996]

It is only possible to apply this technique when the grinding behaviour of both fuels are more or less the same or when the amount of secondary fuels is very small compared with the main fuel flow. Secondary fuels that are pulverised separately from the main fuel can be injected into the coal mill or into the pulverised coal pipelines between the coal mill and boiler.

Other secondary fuels, such as biomass, can also injected into the coal mill together with the coal, although they cannot be pulverised. To allow for a complete combustion of the comparably large sized biomass particles, a grate at the bottom of the boiler can be used.

Liquid secondary fuels are typically blended with liquid fuels before the mix is used.

8.1.4.2 Separate lances or modified existing burners

Separate lances or modified existing burners (separate feeding of the secondary fuel to the burners) are required to handle secondary fuel that cannot be, or is not desirable to be, mixed with the main fuel or to increase the percentage of secondary fuel. This occurs when the secondary fuel has different physical properties (e.g. viscosity, particle size) or the fuel causes health risks (sewage sludge). This applies, for example, to:

- gaseous fuels or the gaseous product streams from gasification, pyrolysis or pre-combustion processes that are to be burned with a solid or liquid fuel
- liquid fuels or the liquid product streams from pyrolysis processes
- pulverised solid fuels.

The burners need to be specially designed for the particular fuel in order to achieve good ignition, a stable flame and good mixing with the main fuel flame in the boiler. The location of the burners in relation to the main burners is important for a good burnout of the fuel.

8.1.4.3 Special grates

Special moving grates at the bottom end of the boiler hopper used for the introduction of secondary fuel lengthen the residence time of those materials in the furnace. Such systems typically avoid the need to pretreat the fuel.

Figure 8.5 gives a schematic drawing of both the grates (2 x 5 MW_{th}) at the bottom end of a boiler and the coal burners applied in Austria. Biomass is fed into the boiler at the small front sides of the grates, which transport the fuel during combustion to the centre of the boiler. Ash from the biomass and bottom ash from the coal combustion, with less than 5 % unburned carbon, falls into the slag remover below the grates. Resulting flue-gases from the grate rise directly into the furnace without any heat losses.

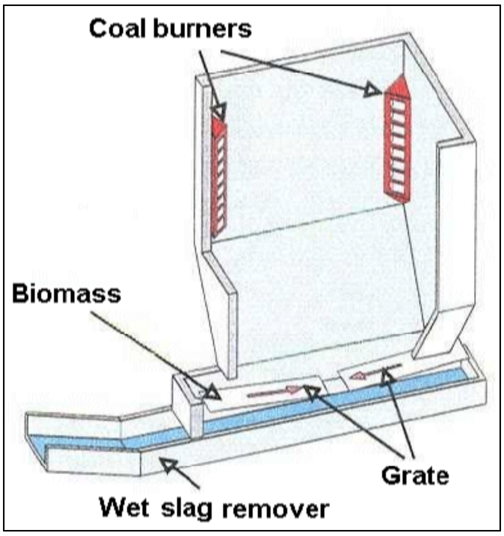


Figure 8.5: Internal grates in pulverised coal-fired boiler
[64, UBA, 2000]

8.1.4.4 Feeding secondary fuels into a fluidised bed boiler

For co-combustion in a fluidised bed boiler, appropriate feeding of the main and secondary fuels is one of the most essential factors for good operation. Good quality of the mixed fuel and low contents of impurities (metals, glass, etc) are also important for good operation.

Good operation and maintenance of the screening and crushing equipment are also very important. Practical problems have occurred when higher amounts of secondary fuel of a different quality from the primary fuel have been fed into the boiler for short periods. This caused disturbances in the combustion process and also affected the load of the boiler. In fluidised bed combustion, sintering problems have occurred.

In conveyors, some operating problems have occurred due to, e.g. blockages caused by long pieces of bark or plastics. These problems can be avoided by proper maintenance of the crushing system.

Secondary fuel should be properly mixed with the main fuel before being fed into the boiler, or there should be a separate feeding system for the secondary fuel so that the secondary fuel feeding can be quickly stopped in the event of any problems. Homogeneous blending of the fuels is required. If high amounts of secondary fuels of a different quality from the primary fuel are fed into the boiler, disturbances in the combustion process may occur, possibly affecting the boiler load.

8.1.5 Co-combustion of secondary fuels

The most direct method of co-combustion of secondary fuel is mixing with the main fuel and burning in the combustion chamber or boiler, but this may lead to technical and/or environmental constraints in the power plant, related to:

- milling and drying capacity of existing coal mills (if the co-combustion fuel is dried and pulverised together with the main fuel)
- feeding of the secondary fuel
- existing the design capacity of power station equipment (e.g. caused by higher wet flue-gas flow in the case of co-combustion of wet fuels)
- combustion aspects of secondary fuel such as ignition, flame stability, flame temperature, NO_X formation and burnout, which may differ from the main fuel
- slagging and fouling, influenced by the chemical composition of the ash (especially potassium, sodium, sulphur) and the melting trajectory of the ash
- thermal behaviour of the boiler, especially radiant and convective heat exchange
- corrosion and erosion of boiler parts (caused by sulphur and chlorine content in the fuel and the operating conditions in boiler combustion in a reducing atmosphere)
- quality and behaviour of by-products and combustion residues
- emissions to the air caused by the content of sulphur, chlorine, heavy metals, organics, etc. in the secondary fuel
- emissions to water caused by the content of sulphur, chlorine, heavy metals, organics, etc. in the secondary fuel.

The above-mentioned constraints can be solved by limiting the degree of co-combustion to only a small portion of the main fuel and/or by proper pretreatment of the secondary fuels.

8.1.6 Control of air emissions by the co-combustion of secondary fuel

Flue-gas cleaning processes and techniques, applied with the co-combustion of secondary fuel, do not necessarily differ from the techniques for cleaning flue-gases from solid, liquid or gaseous fuels as described in Chapters 4, 5, 6 and 7. Depending on the properties of secondary fuel, in particular the content of heavy metals (such as Hg), sometimes additional measures, such as an injection of activated carbon as shown in the example 8.2.3, are applied.

The pollutants SO_2, NO_X and dust are effectively controlled at power plants that are designed and operated according to BAT. A higher input of these pollutants into the firing system can be balanced (clearly within certain limits) by adaptation of the flue-gas cleaning system and will normally not lead to higher emissions. This is reflected in legislation by the fact that limit values for these pollutants have to be calculated according to a formula (mixing rule) when waste (secondary fuel) is co-incinerated (see Directive 2000/76/EG)[6].

Reduction of HCl and HF emissions strongly correlates with SO_2 reduction. Input of chlorinated compounds is limited by the operator of a power plant also for reasons of preventing high temperature corrosion.

8.1.7 Water and waste water treatment

Aqueous releases arise from processes such as wet scrubbing, plume conditioning, wet deslagging, storage and the pretreatment of waste (e.g. drying of sewage sludge). Neutralisation, settlement and physico-chemical treatments may be necessary to remove any contaminants from the water streams generated. Water and waste water treatment systems, applied in the co-combustion of secondary fuel, do not differ from the techniques for treatment of water and waste water from gaseous, liquid or solid fuel fired LCPs, as described in the previous Chapters 4, 5, 6 and 7 [58, Eurelectric, 2001]. If necessary, existing waste water treatment systems can be adapted to the removal of higher loads of pollutants (e.g. Cl, F, Hg).

8.1.8 Handling of combustion residues and by-products

The handling of combustion residues and by-products, as applied with the co-combustion of secondary fuel, does not differ from those techniques for handling combustion residues and by-products cleaning from gaseous, liquid or solid fuel fired LCPs, as described in the previous Chapters 4, 5, 6 and 7. Fly ashes and bottom ashes are generated during the combustion processes.

Power plants are not equipped with systems dedicated to the reduction of heavy metals and Hg (such as acid wet scrubbers and activated carbon systems). Therefore emissions of these pollutants into air will increase (depending on the input) and also their concentration in the fly ash, in the gypsum or in other solid residues from FGD. If the gypsum is washed, emissions into water will also increase.

As the utilisation or disposal of solid residues from combustion is an important economic factor, operators of power plants carefully control the quality of them not to lose established utilisation pathways (mostly by limiting the input of waste into the firing system). Important parameters are the content of alkalis, sulphates, chlorides, silicates, unburned carbon and heavy metals (depending on the specific situation). If solid waste from co-combustion has to be landfilled, concentration of, e.g. heavy metals and leaching behaviour have to measured.

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[6] Annex II of the EU Directive 2000/76/EC provides the requirements on the determination of air emission limit values for the co-incineration of waste (co-combustion of secondary fuel).

8.2 Examples of co-combustion of secondary fuel

This part of Chapter 8 provides a number of examples of techniques and processes currently applied in different co-combustion installations. The aim of the examples is to demonstrate how specific techniques have been applied to new or retrofitted plants in order to ensure a high level of protection for the environment as a whole, taking into account, in each case, the particular site-specific conditions and environmental requirements. However, from the information collected, it is not always clear, if or how each technique described in the examples has been assessed against the definition of BAT given in article 2 (11) of the Directive, as well as against the list of 'considerations to be taken into account generally or in specific cases when determining the best available techniques bearing in mind the likely costs and benefits of a measure and the principles of precaution and prevention' and, consequently, how the technique has been selected and applied. Furthermore, it cannot be assured that the environmental performance presented is constant and continual under all operational conditions, over which time period, whether any problems have been encountered, and what the cross-media effects are. Also, it is not always clear what the driving force is for applying the technique and how the costs and environmental benefits are related in each case. Therefore, the information provided in the following examples is meant only to provide general indications of reported current practice and cannot be considered as appropriate reference points. The techniques that are given as examples arise from information provided and assessed by members of the Technical Working Group as part of the information exchange of LCPs.

EXAMPLE 8.2.1 CO-COMBUSTION OF SEWAGE SLUDGE IN A PULVERISED HARD COAL-FIRED WET BOTTOM BOILER – ANALYSIS OF POLLUTANT FLOWS

Description: In 1996, experiments were carried out on a wet bottom boiler to evaluate the effects of the co-combustion of thermally dried sewage sludge. The example power plant consisted of two boilers, the larger boiler of which had a rated thermal input of 382 MW and was used in the experiments.

The plant is equipped with an SCR in high-dust configuration, followed by an air preheater and ESP. A part of the fly ash is fed back from the ESP to the boiler. The ESP is followed by the FGD plant where the spray dry absorption (SDA) process is applied. Finally, the flue-gas passes through a fabric filter, where the products of the SDA process are separated.

Achieved environmental benefits: The co-combustion of sewage sludge reduces the coal input and thus reduces the emissions of fossile CO_2. For a complete analysis of CO_2 emissions, it is also necessary to take into account the thermal drying and transportation of sewage sludge. These process steps might lead to a negative result of the CO_2 balance, resulting in a net increase in CO_2.

Applicability: The co-combustion of sewage sludge has successfully been applied in several pulverised coal-fired boilers as well as in fluidised bed combustion plants. From a technical viewpoint, it is often limited by the drying potential of the installed coal mills. Especially in the case of hard coal, the coal mills may not have sufficient drying potentials, as the water content of hard coal is much lower than that of sewage sludge. Thus, co-combustion is often limited in these cases to sewage sludge with a dry mass content of more than 90 %, as in the example plant.

Operational data: In 1996, co-combustion took place for three days. During this time, the amount of sewage sludge with a water content of 10 % in the total mass input was 12.5 %, with 5 % in the power input. To compare the measurements for co-combustion, the same measurements were carried out for three days for hard coal only. All in all, 371 tonnes of sewage sludge from seven different sewage plants were fired. The mean quality of the sewage sludge and the fired coal is shown in Table 8.1.

		Combustion of hard coal only	Co-combustion		Accepted values for the use of sewage sludge for co-combustion
	Units	Hard coal 100 %	Hard coal 95 %	Sewage sludge 5 %	
Heating value	kJ/kg	27135	27594	10200	
Ash content	%	11.5	11.3	44.8	
Water content	%	7.5	5.5	10.3	
Pb	mg/kg	17.4	17.8	57.4	900
Cd	mg/kg	0.134	0.129	1.2	10
Cr	mg/kg	10.9	10.76	52	900
Cu	mg/kg	11.3	11.3	269	800
Ni	mg/kg	12.8	12.7	19.1	200
Hg	micro g/kg	0.064	0.058	0.47	8
Zn	mg/kg	34.9	32.8	892	2500
AOX	mg/kg	-	-	444.9	500
PCB	mg/kg	0.034	0.057	0.196	1.2
PCDF/PCDD	µg/kg	-	-	0.009	100

Table 8.1: Mean quality of hard coal and sewage sludge before and during co-combustion

The resulting concentrations of impurities in the flue-gas with and without co-combustion are shown in Table 8.2 for two different sampling points, one upstream of the FGD, and the other downstream of the fabric filter.

	Units	**Mean values of 3 days measurements for 5 % O_2**			
		Measurement point 12 (raw gas)		**Measurement point 13 (clean gas)**	
		Without sewage sludge	With sewage sludge	Without sewage sludge	With sewage sludge
PCDD/PCDF	ng TE/m^3	-		0.002	<0.001
PCB	ng/m^3	-		9.8	8.25
C_{total}	mg/m^3	-		0.4	0.6
benzol	mg/m^3	-		<0.003	<0.003
HCl	mg/m^3	-		4.5	4.5
HF	mg/m^3	-		<0.02	<0.02
Dust	mg/m^3	19.9	13.2	1.5	1
Hg	mg/m^3	0.0093	0.01296	0.00814	0.00861
Cd	mg/m^3	0.00034	0.00037	<0.00001	<0.00001
Tl	mg/m^3	0.00008	0.00002	<0.00003	<0.00003
As	mg/m^3	0.02494	0.01704	0.00006	<0.00003
Pb	mg/m^3	0.02716	0.02520	0.00003	0.00003
Cu	mg/m^3	0.01330	0.01429	0.00043	0.00023
Zn	mg/m^3	0.04252	0.05758	0.00215	0.0014
Mn	mg/m^3	0.02191	0.01296	0.00201	0.00138
Ni	mg/m^3	0.00802	0.00479	0.00033	0.00015
Co	mg/m^3	0.00382	0.00216	0.00005	0.00003
V	mg/m^3	0.02337	0.00954	0.00137	0.00076
Cr	mg/m^3	0.00986	0.01117	0.00068	0.00031
Sb	mg/m^3	0.00097	0.00114	0.00002	<0.00003
Sn	mg/m^3	<0.00002	0.00007	<0.00002	<0.00002
Continuous measurement					
O_2	Vol. %	7.2	7.1	7.2	7.1
Sulphur emission rate	%	-	-	9.0	9.0
Dust	mg/m^3	22.8	8.7	0.8	0.5
NO_X	mg/m^3	-	-	185	185
CO	mg/m^3	-	-	17.0	12.7

Table 8.2: Concentrations of impurities in the flue-gas with and without co-combustion

The following main findings into the fate of the metals resulted:

- the only increase in the atmospheric emissions occurs for mercury (about 6 %), although this increase is not significant as the accuracy of the metrology is low
- only Cr is enriched in the slag tap granulate
- Pb, Ni and Hg can mainly be found in the fly ash and the SDA product
- Cd, Cu and Zn are enriched in both sinks.

	Units	**Slag tap granulate**		**Mix of by-products: fly ash (30 %) and SDA products (70 %)**	
		Coal only	Co-combustion	Coal only	Co-combustion
Pb	mg/kg	34.4	34.6	167	244
Cd	mg/kg	0.097	0.126	1.5	3.1
Cr	mg/kg	88.3	119	102	96
Cu	mg/kg	62.8	135	90	175
Ni	mg/kg	75.4	70.5	96	97
Hg	mg/kg	0.022	0.015	0.13	0.2
Zn	mg/kg	132	298	264	856
PCB	micro g/kg	-	-	0.02	0.02
PCDD/PCDF	mg/kg	-	-	0.001	0.003

Table 8.3: Quality of residues with and without co-combustion

The quality of the eluate of the slag tap granulate does not change, which means that the additional load of metals remains in the slag tap granulate. The increasing input of PCDF/PCDD and PCBs due to co-combustion does not lead to increasing emissions to the air of these substances. They are both destroyed in the boiler at high temperatures of about 1500 °C. The reproduction of PCDF/PCDD by the 'de-novo synthesis' is low if the flue-gas is abruptly cooled down to 130 °C in the air preheater and as the S/Cl ratio is 7/1. The dried sewage sludge was quite easy to handle. Problems occurred whilst adding it to the coal conveyor belt, as dust was formed. In general, experience showed that dried sewage sludge should be stored and transported only in closed systems.

Economics: As co-combustion was only carried out for the test period, no economic data were available.

Driving force for implementation: The operators of sewage plants had to look for new ways to recover the energy content of the produced sewage sludge, as new legislation will not permit disposal from 2005 onwards, and farmers are increasingly refusing to use the sludge as fertiliser. In general, these developments provide an economically efficient way of carrying out co-combustion for the power plant operator.

In the presented example, co-combustion was not realised as the regulatory authority demanded additional measures to reduce the air emissions of mercury. The usual way to do this (injection of coke or activated coke) would have been too expensive and it would have impaired the quality of the SDA product.

Reference literature: [98, DFIU, 2001].

EXAMPLE 8.2.2 CO-COMBUSTION OF SEWAGE SLUDGE IN A PULVERISED HARD COAL-FIRED DRY BOTTOM BOILER – ANALYSIS OF POLLUTANT FLOWS

Description: The example unit has a rated thermal input of 1933 MW and a gross electrical power of 760 MW_e. Co-combustion of thermally dried sewage sludge was tested in 1996 and since 1998 the operator has been authorised to fire dried sewage sludge thermally as well as mechanically. The maximum allowed share of sewage sludge dry matter in the total mass input of the boiler amounts to 4 %. This results in an annual co-combustion potential of 40000 tonnes dry matter of sewage sludge (DM) which is the equivalent production of about 1.82 million inhabitants.

The thermally dried sewage sludge with a DM content of 85 % is stored in a 20 m^3 silo, and from here it is transported to a 600 m^3 coal bunker which stores enough fuel for one day. The mechanically dried sewage sludge with a DM content of about 30 % is stored in a 240 m^3 hopper from where it is directly fed to the coal mills. Thus, it can be handled more flexibly than thermally dried sludge. Both hoppers are equipped with suction plants and subsequent cleaning devices to ensure low emissions to the ambient air and low concentrations of methane inside the hoppers. Without suction plants, the risk of explosion due to high concentrations of methane might be high. The production of methane might especially occur inside the hopper for the mechanically dried sludge due to its high water content.

The co-combustion is mainly limited by the drying potential of the coal mills. If the coal has a water content of more than 14 %, no more sewage sludge can be added as it cannot be dried. Until now, there have been no problems encountered with the boiler, such as corrosion, due to the co-combustion. The staff received anti-hepatitis inoculations and had to wear special overalls and protective masks when working near sewage sludge storage or transportation.

Achieved environmental benefits: The co-combustion of sewage sludge reduces the coal input and thus reduces the emissions of fossile CO_2. It must be stated, that for an overall analysis of CO_2 emissions, the thermal drying and transportation of sewage sludge must be taken into account. These process steps can lead to a negative balance, resulting in a net increase of CO_2.

The savings for a sewage sludge with a mean DM content of 57 % (as assumed for this plant), is about 5800 MJ/t dry matter sewage sludge.

Furthermore, toxic organic substances, such as dioxins or furans, are destroyed. Most of the heavy metals are fixed in the fly ash or in the by-products of the FGD.

Applicability: The co-combustion of sewage sludge has been successfully applied in several pulverised coal boilers as well as in fluidised bed combustion plants. From a technical viewpoint, it is often limited by the drying potential of the installed coal mills. Especially in the case of hard coal, the coal mills may not have sufficient drying potentials as the water content of hard coal is much lower than that of sewage sludge.

Cross-media effects: Atmospheric emissions of volatile heavy metals such as arsenic, selenium and especially mercury might increase due to the co-combustion of sewage sludge. For the example plant, the change of emissions is shown in Table 8.4. Although no significant change in any of the emitted substances can be seen, the conclusion that sewage sludge produces no additional emissions and is thus equivalent to hard coal should not be drawn. Emissions do not change significantly, as the share of sewage sludge in the total mass input does not exceed 5 % and the resulting change in emission is often too small to be measured. Especially in the case of mercury, this fact is endorsed by the limited accuracy of measuring techniques, which are unable to detect small changes in emission. In this plant, about 45 % of the mercury input is estimated to be emitted to the air.

The main sinks for heavy metals are the fly ash and the by-products of the FGD. Their quality does not change significantly due to co-combustion. Thus, the usual ways of recovering the by-products (fly ash, boiler ash, gypsum) can be maintained. As the ash content of sewage sludge is higher than that of coal and as the fuel mass input increases due to co-combustion, the amount of fly ash also increases due to co-combustion.

Operational data: In 1996, during an initial testing period, emissions to the air for the co-combustion of sewage sludge from different regions were measured and compared to the singular combustion of hard coal. The results are presented in Table 8.4. The share of the sewage sludge in the mass input into the boiler ranged between 2.2 and 4.7 %.

	Range of emission values for singular coal firing (mg/Nm^3)	Range of emission values for co-combustion of sewage sludge (mg/Nm^3)
CO	3 – 10	4.7 – 8.5
SO_2	80 – 270	175 – 270
NO_X	150 – 190	170 – 180
Particulate matter	5 – 20	4.6 – 6.1
HF	1 – 3.4	1.5 – 2.5
HCl	0.6 – 7	0.7 – 2.3
Organic carbon	1.0	0.3 – 1.3
Σ Cd, Tl	<0.005 [1]	<0.005
Hg	0.3 – 12 µg/Nm^3 [2]	0.1 – 13 µg/Nm^3 [2]
Σ Sb, As, Pb, Cr, Co, Cu, Mn, Ni, V, Sn	<0.075	<0.075
Dioxins/furans	<5 pg TE/Nm^3	3.3 – 4.8 pg TE/Nm^3

[1] Single measurement in September 1996

[2] Given as two hour mean value; only the concentration in the gas-phase is given as the concentration in the particulate matter was too low for measurement

Table 8.4: Atmospheric emissions for co-combustion of sewage sludges and singular combustion of hard coal during a test period of 10 weeks in 1996

For these measurements, sewage sludge from five different regions was used. The elementary analysis of sewage sludge from two of these sewage plants is shown in Table 8.5, whereas the concentration of impurities in the sludge from all five sewage plants is given in Table 8.6.

	Elementary analysis	
	Min. content (%)	Max. content (%)
Upper heating value (MJ/kg)	7.12	8.7
Lower heating value (MJ/kg)	6.31	7.6
Carbon	20.47	24.54
Hydrogen	2.93	3.69
Nitrogen	2.11	3.37
Oxygen	15.61	18.0
Sulphur	0.81	0.94
Chlorine	0.137	0.297
Fluorine	0.0449	0.0755
Ash	50.61	55.67

Table 8.5: Elementary analysis of sewage sludges from two sewage plants

	Limit values for co-combustion (mg/kg DM)	Concentration in sewage sludges for co-combustion	
		Min. (mg/kg DM)	Max.(mg/kg DM)
Pb	900	74.8	119
Cd	10	0.97	3.4
Cr	900	63	560
Cu	800	231	758
Ni	200	23.1	75
Hg	8	0.398	1.6
Zn	2500	892	1600
PCB	0.2	0.08	0.187
PCDD/PCDF	100 ng TE/kg DM	21 ng TE/kg DM	71 ng TE/kg DM
AOX	500	164	1240
Notes: dm = dry matter			

Table 8.6: Concentration ranges of impurities in the sewage sludges from different sewage plants during the test period

No relevant concentrations of dioxins/furans were measured in any of the by-products (ash, gypsum, waste water). The increase in heavy metal content in the by-products was insignificant and the quality of the by-products was virtually unchanged, thus the boiler ash, fly ash and gypsum were recovered in the usual way.

About 99 % of the heavy metals (except mercury) can be found in the fly ash or in the by-products of the wet FGD. Approximately 55 % of the mercury is also captured in this way. The remaining 45 % is emitted into the air.

Economics: There are no specific data available for the example plant presented. The full cost for the co-combustion of sewage sludge containing 30 – 92.5 % dry matter is estimated to be EUR 46 – 52/t respectively.

Driving force for implementation: Operators of sewage plants had to look for new ways to treat the produced sewage sludge, as new legislation will not permit disposal any more from 2005 onwards and farmers are increasingly refusing to use the sludge as fertiliser. These developments provide an economically efficient co-combustion method for power plant operators.

Reference literature: [98, DFIU, 2001], [154, Maier, et al., 1999], [155, Buck and Triebel, 2000], [157, Rentz and Sasse, 2000].

EXAMPLE 8.2.3 CO-COMBUSTION OF SEWAGE SLUDGE IN A LIGNITE-FIRED FLUIDISED BED COMBUSTION PLANT WITH MERCURY CONTROL

Description: The presented CFBC boiler (Figure 8.6) has a rated thermal input of 275 MW and mainly produces steam for a lignite processing plant. After some initial tests of the co-combustion of sewage sludge, a mercury emission control device had to be installed to allow for continuous operation. For this purpose, the flue-gas duct was equipped with a device which can introduce lignite coke dust (produced in open-hearth process) into the flue-gas via a nozzle. After 20 metres, the loaded sorbent is separated in the ESP. In common entrained-flow reactors, the loaded coke is separated from the flue-gas in fabric filters. In this case, the fabric filter was renounced and the coke was separated in the existing ESP together with the particulate matter. The amount of sewage sludge in the total rated thermal input can be up to 4 %.

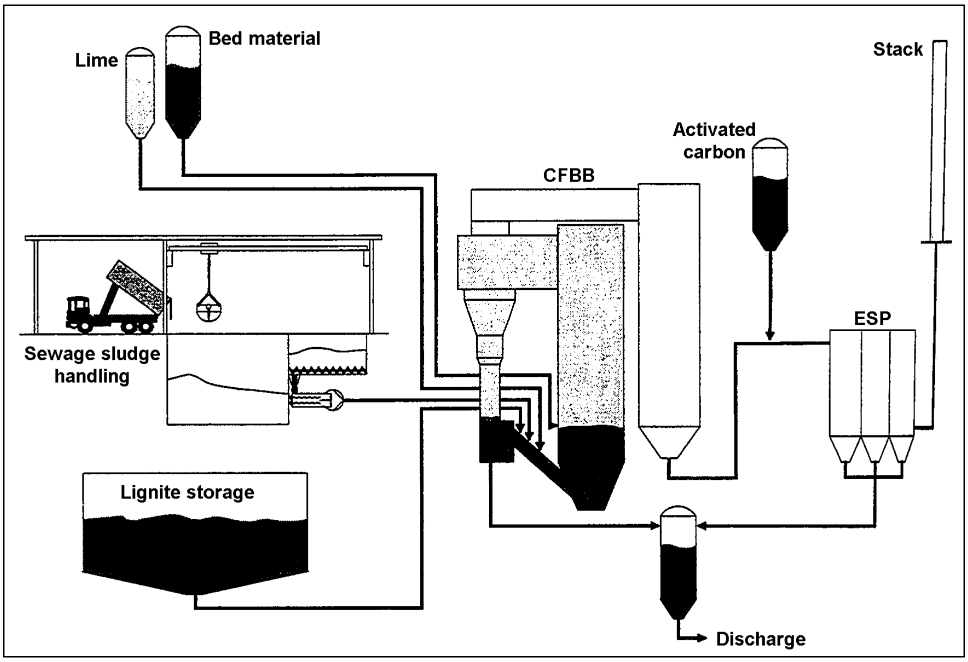

Figure 8.6: Injection of activated carbon into the flue-gas channel from a CFBB with co-combustion of sewage sludge
[75, Hein, et al., 2000]

Achieved environmental benefits: The energetic use of sewage sludge reduces the consumption of lignite. Thus consumption of resources is reduced as well as emissions of fossile CO_2. Mercury emission control reduces the atmospheric mercury emissions by up to 85 %, with the resulting emissions being far below the legal emission limit values.

Applicability: The co-combustion of sewage sludge in CFB plants has been shown to be technically viable if the share in the rated thermal input does not exceed 5 %. The emissions to the air do not change either (e.g. SO_2, NO_X) or may only marginally increase (e.g. heavy metals, dioxins, furans). Nearly 100 % of the non-volatile metals can be found in the fly ash. The only problem might be caused by mercury. The nozzling in of lignite coke in the example plant, is a well known control technique in waste incinerators to reduce heavy metals, dioxins and furans. The only restriction of this flue-gas cleaning process is the temperature, as there is a temperature limit of 170 °C which should not be exceeded.

Cross-media effects: The mercury control consumes about 70 – 80 kg/h of lignite coke. The loaded coke is separated from the flue-gas together with the fly ash and has to be disposed of. The mercury content in the fly ash increases from 1 mg of Hg/kg of fly ash to 2.7 mg Hg/kg fly ash, due to the loaded coke.

Operational data: The concentration of mercury in the flue-gas for co-combustion of sewage sludge without emission control was about 0.025 mg/Nm^3. The injection of lignite coke at a rate of 80 kg/h reduced the emissions by 75 to 85 %, i.e. to about 0.004 mg/Nm^3. Nearly the same separation efficiency could be reached with an injection rate of 50 kg/h, and this value was reached only two hours after starting the injection. This indicates, that it needs a certain time to build up an active cloud of coke dust inside the ESP to separate the mercury effectively. The input of lignite at full load amounts to 77 t/h, the input of sewage sludge amounts to 25 t/h. The characteristics of the two fuels are shown in Table 8.7.

	Water content %	Ash content %	Mercury content mg/kg dry matter
Lignite	52.5	1.75	0.09
Sewage sludge	73.2	12.6	1.33

Table 8.7: Characteristics of the lignite and the sewage sludge

The leachability of the fly ash does not change due to the addition of lignite coke. Thus the heavy metals remain fixed in the lignite coke.

Economics: Exact values for the lignite coke injection are not known. But the costs for the injection of coke lignite can be compared to those of an entrained-flow reactor. The investment for the presented technique should be far below that of an entrained flow reactor as the installation is simpler and no additional fabric filter is needed.

Driving force for implementation: The motivation for co-combustion is the potential economic benefit as from 2005 on, sewage sludges are not allowed to be disposed of anymore and alternative combustion in waste incineration plants or in special incineration plants for sewage sludge is expensive. The lignite coke injection was installed to comply with legal emission limit values.

Reference literature: [98, DFIU, 2001], [75, Hein, et al., 2000], [158, Wirling, et al., 2000], [159, Thomé-Kozminsky, 1998], [160, Rentz, et al., 1996].

8.3 Current consumption and emission levels in the co-combustion of secondary fuel in LCPs

8.3.1 Overview of secondary fuels co-combusted in LCPs

The co-combustion of secondary fuel impacts on the plant efficiency, emissions to air, and water also has effects on the quality of the combustion residues and by-products.

The amount of impact is determined by the way the properties of the secondary fuel differ from the main fuel. The main physico-chemical properties, which describe the quality of a fuel, are:

- calorific value
- ash content
- water content
- volatile matter, and
- chemical composition (especially C, H, O, N, S, Al, K, Na, P, Cl, F, as well as Hg and other metals).

The main types of secondary fuel that have been used for co-combustion in LCPs are shown in Table 8.8 and the most important ones on this list are sewage sludge and biomass/wood.

Type of secondary fuel	Examples of secondary fuel
Animal (by-) products	Animal meal, tallow, meat and bone meal Manure and chicken litter
Chemicals	Organic acids and liquid solvents Phosphor oven gas
Municipal waste	Waste paper Packing materials Plastics Refuse derived fuels (RDF)
Oily materials	Tar Waste oil
Recovered fuels	Fuels derived from different high calorific waste fractions
Sludge	Sewage Paper (such as de-inking, bio and primary sludges)
Tyres	Shredded tyres
Vegetables	Energy crops as willow Agricultural residues such as straw, cereal plants, pasture from landscape cultivation
Wood	Wood residues, demolition wood, waste wood, forest residues, wood chips Biomass pellets/briquettes

Table 8.8: Types of secondary fuel co-combusted in LCPs

Waste derived fuels are mainly solid or liquid with a significant amount of ash. For this reason co-combustion is more or less limited to the application in coal-fired boilers. Also some of these materials can be classified as hazardous, as they may be contaminated with hazardous materials. Table 8.9 to Table 8.11 also gives some examples of secondary fuels used in coal-fired power stations. They also show some examples of the composition of different types of secondary fuel used in LCPs. More information can be found in CEN proposals. In this context, reference is also given to Table 4.32 and 4.33 presented in Chapter 4 concerning the combustion of coal and lignite.

Parameter	Units	Range (lignite and hard coal)	Range (sewage sludge; municipal – industrial)
Water content	weight-%	3 – 60	65 – 75
Calorific value H_u	MJ/kg dry mass	7 – 38	9 – 12
Ash content	weight-%	3 – 17	40 – 60
Volatiles	weight-%	17 – 60	13 – 47
Fixer C	weight-%	19	1
C	weight-%	60 – 80	33 – 50
H	weight-%	3 – 9	4 – 7
N	weight-%	0.5 – 2	2 – 3
S	weight-%	0.5 – 3	0.5 – 2
Cl	mg/kg dry mass	200 – 300	500 – 3000
F	mg/kg dry mass	16 – 20	100 – 350
As	mg/kg dry mass	0.4 – 18	4 – 9.2
B	mg/kg dry mass	no data	30 – 55
Ba	mg/kg dry mass	no data	300 – 500
Be	mg/kg dry mass	0.1	0.9 – 2
Pb	mg/kg dry mass	0.4 – 50	15 – 412
Cd	mg/kg dry mass	0.02 – 5	4 – 6.5
Co	mg/kg dry mass	0.6 – 21	2 – 13.4
Cr	mg/kg dry mass	1.4 – 39.1	40 – 108.6
Cu	mg/kg dry mass	1 – 33	30 – 434
K	mg/kg dry mass	no data	1500 – 2300
Mn	mg/kg dry mass	88 – 160	210 – 1000
Na	mg/kg dry mass	no data	1100 – 4400
Ni	mg/kg dry mass	1.6 – 40.5	30 – 57
Hg	mg/kg dry mass	0.1 – 0.3	0.2 – 4.5
Se	mg/kg dry mass	no data	<5
Sb	mg/kg dry mass	1 – 5	2.4 – 8.5
Th	mg/kg dry mass	0.1 – 0.3	1.2 – 2
V	mg/kg dry mass	1 – 105	9 – 35.4
Sn	mg/kg dry mass	4	10 – 100
Zn	mg/kg dry mass	5 – 60	420 – 1600
AOX	mg/kg dry mass	no data	350

Table 8.9: Example of coal/lignite and sewage sludge compositions
[64, UBA, 2000]

Because of the different origins of secondary wood fuel such as waste wood, demolition wood (with and without wood preservatives) and pressboard residues, the impurities and contamination levels may vary widely. Table 8.10 shows the variation in impurities and the contamination of different waste wood examples, where some of these contain wood treated with wood preservatives (e.g. demolition wood).

Element	Units	Waste wood A	Waste wood B	Waste wood C	Demolition wood
Nitrogen	(mg/kg)	n.a.	7600	7300	2400
Sulphur	(mg/kg)	1000	<20	5500	1700
Chloride	(mg/kg)	2000	200	320	1184
Fluoride	(mg/kg)	120	3	50	88
Cd	(mg/kg)	10	1	n.a.	4.1
Hg	(mg/kg)	1	<0.5	n.a.	1.5
As	(mg/kg)	2	1	n.a.	4
Co	(mg/kg)	2	n.a.	n.a.	4.1
Cu	(mg/kg)	1000	16	23	1388
Cr	(mg/kg)	120	19	32	48
Mn	(mg/kg)	100	n.a.	n.a.	n.a.
Ni	(mg/kg)	20	4	5	15.8
Pb	(mg/kg)	1000	140	510	762
Sb	(mg/kg)	10	n.a.	n.a.	11.8
Zn	(mg/kg)	20	12	n.a.	23.5
Note: n.a. = not available					

Table 8.10: Examples of waste wood types composition used in LCPs
[75, Hein, et al., 2000]

Substance	Units	Bark	Larch - chips	Bark + chips + dried sewage sludge	Bark + chips + wood from demolition	Bark + chips + plastics	Bark + pressboard + plastics from electronic scrap recovery
Carbon	%	49.78	51.01	47.06	48.69	50.64	50.43
Hydrogen	%	5.41	6.10	5.59	5.77	5.73	5.75
Oxygen	%	36.98	42.28	30.06	36.17	36.85	34.95
Nitrogen	%	0.45	0.21	2.82	1.48	0.70	1.42
Total sulphur	%	0.04	0.02	0.40	0.12	0.05	0.09
Ash	%	7.34	0.38	14.07	7.77	6.03	7.37
Combustibles	%	92.66	99.62	85.93	92.23	93.97	92.63
Volatiles	%	69.06	83.04	66.70	72.71	71.39	70.56
H_o	kJ/kg	19658	20380	19111	19601	20112	20351
H_u	kJ/kg	18478	19050	17891	18343	18862	19097
Chloride	% Cl	0.000	0.000	0.112	0.035	0.071	0.135
Fluoride	% F	0.000	0.000	0.012	0.003	0.004	0.004

Table 8.11: Variation of impurities in different wood – secondary fuel mixtures
[64, UBA, 2000]

8.3.2 The degree of secondary fuel co-combusted in LCPs

Table 8.12 presents some experiences with the co-combustion of secondary fuel in coal-fired power stations. The major part of these experiences concerns the co-combustion of less than 10 % on a thermal basis. References with higher co-combustion rates concern fluidised bed boilers or the co-combustion of separately pulverised wood in pulverised coal-fired boilers.

Large scale demonstrations have been performed with sewage sludge and wood chips. Table 8.12 includes an overview of power plants where secondary fuels have been co-combusted.

In Finland for example, about 400000 t/year (in 2000) of source separated waste is currently co-combusted in about 40 boilers, the proportion of waste fuel being 5 – 30 % of the main fuel. Recovered fuel is co-combusted most often in fluidised bed boilers, where the main fuel is peat, coal or wood fuel. The main components of the waste fuel are paper and board, certain known plastics materials and RDF. In this country, the quality categories and the quality control methods for waste-derived fuels for co-firing are prescribed by the national standard.

Country	Power (MW_e)	Secondary fuel	Co-firing degree thermal %	Handling of co-combustion fuel	Remarks
Austria					
	124	Biomass (bark)	3	The boiler has two air-cooled forward pushing grates at the bottom of the boiler with a capacity of 5 MW each.	In operation since 1994. See Section 8.1.4.3 for details
	137	Biomass	3	Gasification, gas burners and reburning	Gasified biomass is co-combusted as reburning fuel. In operation since 1997
Denmark					
	77.5	Straw	50	Fluidised bed combustion	Plant designed for coal/straw fuel mix
	125	Pulverised wood	20	Separate wood burners	Pulverised wood was burned in two specially adapted burners. No negative effects were noticed and it is expected that higher co-firing percentages should be possible. The NO_X emission was reduced by 35 % and the quality of the fly ash remained good.
Germany					
	170	Sewage sludge	11		
	195	Sewage sludge	3.5		
	235	Sewage sludge	3.5		
	280	Biomass pellets	Max 10 mass	Separate wood mills, wood burners	The biomass is pulverised in hammer mills and the boiler has a grate at the bottom..
	382	Sewage sludge	5		
	565	Sewage sludge	0		
	805	Sewage sludge	<0.5		
	913	Sewage sludge	1		
	930	Sewage sludge	5		
	1074	Sewage sludge	1.5		
	1280	Sewage sludge	0.07		
	1933	Sewage sludge	1.1		
Finland					
	>40 boilers	REF, RDF Selected municipal waste			
Italy					
	320 MW_e	RDF		Pulverised with coal	RDF is obtained from municipal solid wastes by mean of milling, magnetic separation of metallic material, trommeling and classification to separate organic fraction and inerts
	48 MW_{th}	RDF	10 – 15 % based on 33 MW_{th} only	Two solutions: 1) pulverised with coal, 2) dedicated feeding line	Co-firing has shown a higher level of unburned

Country	Power (MW$_e$)	Secondary fuel	Co-firing degree thermal %	Handling of co-combustion fuel	Remarks
The Netherlands					
	403	Phosphor oven gas Sludge	3	Separate gas burners Pulverised with coal	In operation since 1996 Large-scale tests
	518	Liquid organic residue	1		In operation since 1995
	518	Biomass pellets	5	Pulverised with coal	In operation since 1998
	600	Waste wood	3	Separately milled, wood burners	In operation since 1995
	600	Waste wood	5	Gasification with gas cleaning, gas burners	In commissioning in 2000
	630	Dried sewage sludge	3	Pulverised with coal	Several large scale tests
	645	Paper sludge	Max 10 mass	Pulverised with coal	In operation since 1997
US					
		Wood (willow)	Max 10 mass	Separate wood mills, wood burners	
		Wood	Max 5 mass	Pulverised with coal	
	2x25	Wood/RDF	50/15	Bubbling fluidised bed combustion	
	54	Wood	Max 40		Short test, natural gas support burner
	100	Wood (saw-dust, lopping)	Max 13.5 masss		Large-scale test, increased excess air, decreased steam temperatures
	350	Refuse-derived fuel	6		
	560	waste wood	5		Cyclone combustor

Table 8.12: Experience with co-combustion in some LCPs in some EU Member States and the US [58, Eurelectric, 2001]

8.3.3 General effects of the co-combustion of secondary fuel

The handling, and in particular the combustion, of secondary fuel can lead to complications according to the emission levels, the plant efficiency and availability as well as the quantity and quality of the residues, by-products and waste water. These effects are influenced by the nature of the secondary fuel, in particular with regard to its:

- toxicity (also pathogenic germs)
- explosion risk (gaseous fuels and dust explosions)
- flammability (liquid fuels)
- moisture content of the fuel
- spontaneous heating (biomass)
- odour
- fluidity (for sludge and solids)
- grindability.

These aspects have to be addressed when choosing the fuel to enable proper and safe co-combustion of the secondary fuel.

8.3.4 Effects of co-combustion on plant efficiency

When the boiler is fired with a fuel mix, the power station efficiencies of the conversion of the energy inputs of the individual fuel streams to the energy output have to be determined. This means that, in order to determine the effect of co-combustion on plant efficiency, the conversion from secondary fuel to energy output as well as the influence of co-combustion on the main fuel conversion have to be considered.

The efficiency of the conversion from waste to energy is influenced by:

- moisture content of the fuel
- fuel reactivity
- grindability of the fuel
- efficiencies of the required pretreatment processes before combustion
- required house load for handling and pretreatment of the fuel
- calorific value
- ash content.

The co-combustion of secondary fuel can influence the conversion of the main fuel to energy output in the following ways:

- excess air may be needed to ensure proper combustion
- flue-gas temperature and flow in the boiler may change
- there may be an increase in unburned carbon in the fly ash
- steam temperatures may change
- the efficiency may be affected by the drying of secondary fuel on- or of-site.

Typical examples of the efficiency of the conversion of secondary fuel to electricity, compared with the efficiency of the main fuel are given in Table 8.13.

Example cases	Efficiency changes	Remarks
Effect of co-combustion of wood	4 – 5 % of the coal will be replaced with pulverised wood. This capacity is based on the availability of the wood rather than on the co-combustion capacity of the boiler. The increase in the moisture content of fuel has only minor effects on efficiency when a lower heating value is used	Wood chips, with a maximum dimension of 3 cm, are transported to the power station in containers and stored on an area that has a capacity for one day's co-combustion of wood. After unloading the containers, a conveyer belt transports the wood to a hammer-mill. The fine particles are fed to a dust collector; the coarse particles are stored in one of the day bunkers. Wood chips from these bunkers are fed to two mills to grind the wood to a powder with specified particle dimensions (90 % <800 µm). Together with the pulverised wood from the hammer-mills, the wood powder is transported to a silo near the boiler. A dosing system distributes the wood over the wood burners, which are located below the coal burners
Effect of co-combustion of sewage sludge and manure. How efficiency is affected by the drying of secondary fuel	Furthermore, the high moisture content of the fuel will adversely affect the boiler performance	Fuel that is too wet to be dried in a coal mill has to be dried before mixing with the main fuel. Typical examples of secondary fuel that often have to be dried are sewage sludge and manure (e.g. chicken litter), with moisture contents exceeding 50 %. The drying capacity of a coal mill can be too low to dry these fuels sufficiently

Table 8.13: Examples of some of the effects of co-combustion on LCP efficiency

8.3.5 Effect of co-combustion on plant performance

Apart from the possible influence on plant efficiency caused by humidity or ash content, co-combustion may also influence the plant performance. This may result in a decrease in the nominal load, or the load control speed of the power plant, caused by the capacity constraints of the components. For example, the capacity of the induced draft flue-gas fans can limit the co-combustion factor of wet fuels. Plant performance (and availability) may also be influenced by corrosion (due to the sulphur and chlorine content of the fuel), erosion, slagging or fouling (due to the alkali content of the ash) of the boiler. Adapting the LCP equipment for the pretreatment or pre-conversion of the fuel, or limiting the degree of co-combustion, helps to prevent a decrease in plant performance.

The influences on plant efficiency and plant performance increase as the secondary fuel deviates more from the original design fuel(s) of the boiler. The following list details a few ways in which the co-combustion of secondary fuel may affect the LCP performance:

- existing design capacity of power station equipment (e.g. caused by higher wet flue-gas flow in the co-combustion of wet fuels)
- combustion aspects of secondary fuel such as ignition, flame stability, flame temperature, NO_X formation and burnout, which may differ from main fuel
- slagging and fouling, influenced by chemical composition of the ash (especially potassium, sodium, sulphur) and melting trajectory of the ash
- thermal behaviour of the boiler, especially radiant and convective heat exchange
- corrosion and erosion by salts of boiler parts (caused by sulphur and chlorine compounds in the fuel and the operating conditions in the boiler combustion, e.g. the reducing air)
- quality and behaviour of the by-products and combustion residues
- emissions to the air caused by the sulphur, chlorine, heavy metals, organic substances, etc. content in the secondary fuel
- emissions to water caused by the sulphur, chlorine, heavy metals, organic substances, etc. content in the secondary fuel
- impacts on the flue-gas cleaning units due to changes in the composition of the flue-gas (especially deactivation of the DENOX catalysts by alkalis, As, P or F; increased fly ash separation by ESP; affects on the FGD)
- air and water emissions from waste pretreatment (e.g. drying of sewage sludge).

Table 8.14 shows some examples of the most important effects of the co-combustion of secondary fuel on the performance of LCPs.

Secondary fuel	Comments	Performance effects
Animal meal	Effect on the calorific value	Problems created by the phosphorus, chlorine and alkaline metals of the secondary fuel
Meat and bone meal		Effect of the phosphorus creating calcium phosphate that creates plugging. Other problems are the alkaline metals (sodium potassium) and chlorine.
Tallow	This is typically used as a substitute to fuel oil	It can contain more than 0.05 % phosphorus and create problems.

Table 8.14: Effects caused by secondary fuel when co-combusted in LCPs

8.3.6 Effects of co-combustion on emissions to air

The chemical properties of the co-combusted secondary fuel are the principal determinant factors for air emissions. Elevated concentrations of elements in the secondary fuel such as mercury, compared to the concentrations of those elements in coal or lignite, will correspondingly result in higher air emissions from the stack. Air emission control measures may even out the differences, which can arise from additional emissions generated by co-combustion.

8.3.6.1 Particulate matter

Dust emissions from the stack may change with co-combustion due to different physical and new chemical composition of ash which can modify especially the ESP performance. However, dry solid fuels that can release very fine particles, could give rise to fugitive dust emissions, especially in handling and storage areas. Dust emissions can depend on the secondary fuel especially if the ESP performances are modified by the new composition of the ash.

Particulate matter is present in flue-gas for a number of reasons. Some of it is related to the ash entrained into the flue-gas by turbulent conditions in the combustion chamber. Light fuels such as straw are particularly prone to this. Similarly, the flue-gas can entrain partially burned fuel.

Compounds and metals such as cadmium and especially mercury volatilised in the combustion chamber can condense into particulate matter when the temperature drops after combustion. This material can form a submicron fume that can be difficult to remove. Particulates can also be generated by routine online cleaning such as during sootblowing.

8.3.6.2 Acid gases

Depending on the type of secondary fuel used, higher emissions of acid gases may result. These gases are hydrogen chloride, sulphur dioxide, hydrogen fluoride and nitrogen oxides. The concentration of various compounds in the secondary fuel will determine the levels of respective acid gases in the flue-gas and the abatement measures applied.

8.3.6.3 Carbon oxides

The fossil CO_2 emissions decrease when renewable secondary fuel is co-combusted. This is one of the primary goals and achievements of the co-combustion of biomass. Due to the replacement of the primary fossil fuel, the emission of ‘fossil CO_2’ decreases, whereas the CO_2 originating from the biomass is not accounted for. CO_2 reduction is generally the argument in favour of the co-combustion of biomass, even to counter the argument that emissions into the air of other components might increase somewhat. Emissions of carbon monoxide do not rise significantly in co-combustion.

8.3.6.4 Halides

Halide emissions may be higher in the co-combustion of secondary fuels with high Cl and/or F contents. Chloride and fluoride are not completely abated by the typical flue-gas cleaning installations of coal-fired power plants, for example. The concentrations of these components can be high if compared to the emission values generated by waste incinerators. Emissions, mainly of fluoride, are higher when a gas-gas heat-exchanger is applied for reheating the cleaned flue-gases from the FGD.

8.3.6.5 Nitrogen oxides

The waste or recovered fuel may have a beneficial or detrimental impact on NO_X emissions depending on how similar the waste or recovered fuel is to the coal with which it is co-fired. High volatile coals may increase the flame temperature, thereby potentially forming more NO_X. Secondary fuel with a high percentage of moisture ignites slowly with a low adiabatic flame temperature, thereby forming less NO_X. Installations with NO_X abatement techniques have higher flexibility in accepting secondary fuels with a higher fuel-nitrogen content.

8.3.6.6 Sulphur oxides

Secondary fuels with much higher sulphur contents than the main fuel (coal, lignite peat) can sometimes cause only marginally higher flue-gas concentrations, assuming an adequate SO_2 removal from the flue-gas. However, many of these secondary fuels may have a lower sulphur content than the primary fuel. In this case, the overall emissions of sulphur compounds may decrease.

8.3.6.7 VOCs and dioxins

Volatile organic compounds (VOCs) in the flue-gas represent unburned fuel. Co-combustion may lead to an increase in the emissions of VOCs. However, the emissions of hydrocarbons, volatile organic compounds and PACs do not change significantly in co-combustion when a good burnout is achieved [58, Eurelectric, 2001].

Polychlorinated dibenzo-p-dioxins and polychlorinated dibenzo-furans (‘dioxins and furans’) are one particular type of VOC, dioxin being a generic term for over 200 such compounds.

Dioxins and dioxin-precursor substances can be present in secondary fuels, such as demolition wood, refuse derived fuel (RDF), in small quantities that are destroyed in the combustion chamber. However, they can reform by the so-called ‘de-novo synthesis’ process subsequently, from precursors such as chlorinated benzenes, PCBs or non-chlorinated precursors, where there is an associated supply of inorganic chlorine. The mechanism for their reformation is not fully understood, but it is thought that the presence of copper, soot and fly ash can assist in the process, which occurs mostly between the temperatures of 200 and 450 ºC. Due to these effects, it has been identified that co-combustion of certain types of waste may result in higher dioxin emissions. Dioxin emissions can be reduced with an activated carbon injection to flue-gases.

However, emissions of dioxins and furans from coal-fired plants are low due to their specific combustion characteristics and the sulphur content of the fuel which impedes the formation of these compounds. This does not change with co-combustion, even with secondary fuel with a high chlorine content.

8.3.6.8 Metals

Metals (e.g. heavy and toxic metals) are already present to a certain extent as natural elements in fossil fuels. Secondary fuels such as sewage sludge and fuel derived from waste or the demolition of wooden constructions may contain metals, as shown in Table 8.9 and Table 8.10, in a higher quantity than conventional fuel. Waste oil produces little ash and so toxic metal compounds present in the fuel are unlikely to end up in the flue-gas.

Some metals remain in the furnace bottom ash whilst others in the flue-gas may condense downstream from the combustion chamber, where they become particulates. Some highly volatile metal compounds such as cadmium, mercury, talium and selenium will remain in the vapour phase or in an ultrafine fume. In considering (compositions of) secondary fuel, the Hg concentration is typically one of the most critical of all the elements because of its volatility [58, Eurelectric, 2001]. Due to limitations of the waste input (only a few per cent of the total thermal input of a power plant come from co-combusted waste) and due to comparable low concentrations of Hg in the raw gas of pure coal fired power plants, the raw gas concentration of Hg will not rise significantly as a result of dilution effects (furthermore, the limit of detection is often the restricting parameter). However, emitted loads will increase as a result of the very high flue-gas volumes. Looking at the total emission of other heavy metals, some increase is possible due to possibly higher concentrations of Pb, Co, Tl, and Se [58, Eurelectric, 2001].

The average costs of retrofitting additional control techniques to reduce the concentration of Hg in the clean flue-gas are presented in the following table.

Coal type (sulphur content)	Existing air pollution control device	Retrofit Hg control	Current cost (US cents/kWh)	Project cost (US cents/kWh)
Bituminous (3 % S)	Cold-side ESP + FGD	PAC	0.07 – 0.12	0.04 – 0.07
	FF + FGD	PAC	0.03 – 0.05	0.02 – 0.03
	Hot-side ESP + FGD	PAC + PFF	0.15	0.09
Bituminous (0.6 % S)	Cold-side ESP	SC + PAC	0.1 – 0.18	0.06 – 0.1
	FF	SC + PAC	0.4 – 0.08	0.03 – 0.05
	Hot-side ESP	SC + PAC + PFF	0.18 – 0.38	0.1 – 0.23
Sub-bituminous (0.5 % S)	Cold-side ESP	SC + PAC	0.012 – 0.19	0.07 – 0.11
	FF	SC + PAC	0.04 – 0.11	0.03 – 0.07
	Hot-side ESP	SC + PAC + PFF	0.14 – 0.27	0.09 – 0.16

Notes:
FF = Fabric filter **FGD = Flue-gas desulphurisation** **ESP = Electrostatic precipitator**
PAC = powdered activated carbon; **PFF = polishing fabric filter;** **SC = Spray cooling**

Table 8.15: Estimates of current and projected annual operating costs for retrofitting mercury emission control technologies
[171, UN ECE, 2002]

8.3.6.9 Plume

Fuels with high moisture contents, such as poultry litter, are susceptible to visible plume formation. There are three generic techniques for conditioning exhaust gases to prevent visible plume formation from the stack:

- exhaust gas reheating
- exhaust gas condensation
- flue-gas temperature control.

Condensation techniques produce large volumes of liquid for disposal, which can be contaminated by polluting substances and may require treatment by neutralisation.

8.3.6.10 Odour

The storage and handling of secondary fuel such as odorous sludge can generate odour emissions. Especially drying installations need provisions against odour emissions. Depending on the fuel and the local situation, transportation and storage should take place in closed areas.

8.3.7 Effects of co-combustion on emissions to water

Co-combustion of secondary fuel may affect the emissions to water. However, most sources of waste water like cooling water, condensate or demineralised waste water are not influenced by co-combustion. The sources of waste water that may be influenced are:

- rinsing waters from solid fuel storage and surface run-off (rainwater)
- the common factor in all dewatering (drying) processes is that the water separated (filtrate or decant water) is polluted to differing extents. This is particularly true when dewatering at higher temperatures and represents a weighty secondary pollution of the sewage treatment plant
- as described in Chapter 3, flue-gas desulphurisation is the main source of waste water, as it removes SO_2 as well as other pollutants, such as heavy metals, from the flue-gases. The heavy metal concentrations in the effluent of the waste water plant is, to a high extent, independent of the influent concentrations and will, therefore, not be affected by co-combustion
- dust control with water of open fuel storage can result in waste water, if this water is not internally reprocessed, which is normally the case for coal storage. If secondary fuel is not stored and handled properly, rainwater may also be contaminated unnecessarily. ‘Good housekeeping’ will prevent substances being spilled and transferred to drains
- condensation techniques applied to plume conditioning produce large volumes of liquid for disposal, which can be contaminated by polluting substances and may require waste water treatment
- the storage and handling of liquid secondary fuels may be diluted into the waste water treatment system. The use of wet sludge spread out over the coal in the coal yard might also typically involve dilution into the waste water treatment system.

8.3.8 Effects of co-combustion on quality of combustion residues and by-products

Basically, the starting point for co-combustion is to prevent a decrease of the quality of combustion residues and by-products. This has to be achieved by pretreatment of the secondary fuel or by limiting the degree of co-combustion. The quality of residues and by-products has two aspects – technical and environmental quality:

- technical quality is the expression of various parameters, which together determine, to a large extent, the applicability of the by-product. Apart from the purely technological parameters (e.g. stiffness, porosity, particle size, moisture content), the contents of elements such as chloride, phosphorus, sulphate and carbon are also important. This applies especially to ashes in concrete and cement. Technical requirements will normally be issued by the (association of) construction industry. As the composition of the ash can be different than without secondary fuel, valorisation can be a problem. (not all the secondary fuels are normally EN-450 on ash in concrete
- environmental quality of the by-product is the expression of how heavy metals can leach from the product in which they are applied, to the environment. Leaching characteristics determine, apart from the technical properties, if the by-products are allowed to be applied for the products they are used for.

The impact of co-combustion on the by-product quality has been extensively investigated and reported in some countries, such as in the Netherlands. Given the high removal rates of ESP, more than 99 % of the elements are found in the ashes. Generally, changes in the composition of the fuel will result in changes in the composition of ashes with the same magnitude. More specifically, elements that do not vaporise in the combustion process will have the same concentration in all ash types. For more volatile elements, however, redistribution takes place in the sense that they will be found more in fly ash and flue-gases upstream from the ESP than elements that do not vaporise.

The conclusion is, ash composition in the event of co-combustion will change correspondingly with other compositions of the secondary fuels. The elemental composition of the by-products can be predicted to an extent that it is possible to determine the margins of which, when and to what quantities secondary fuels can be co-combusted.

Ash composition, in the case of co-combustion, will change correspondingly with other compositions of the secondary fuel. The elemental composition of the by-products can be predicted to such an extent that it is possible to determine the margins of which, when, and to what quantities secondary fuel can be co-combusted.

Heavy metals (some less, some more) have the risk of leaching into the environment after they have been exposed to water for a very long time. Leaching characteristics are less important for fly ash when it is used in immobilised applications in the cement and concrete industry.

Bottom ash, however, applied for example as a layer under a road, can involve leaching of some elements in the long term. A shift in microelemental composition and leaching may pose a constraint to the application of bottom ash as a consequence of co-combustion.

Gypsum will hardly be affected by changing the composition of the fuel. There is no hazard of leaching, as the product is applied principally inside buildings, where contact with water is not the issue. But according to quality requierements, gypsum is normally washed before it leaves the power plant.

Filter ashes of pretreatment processes, such as gasification or CFBs, are generally more difficult to apply and may have to be sent for disposal. Techniques to immobilise the microelements can open possibilities for applications.

For an overall evaluation of the environmental impact of heavy metal concentrations, the immobilising and stabilising of heavy metals in the residue should be taken into account as well as the calculation of the total content. The extent of immobilisation can be calculated from the heavy metal concentrations in the eluate. Table 8.16 and Table 8.17 show the effect of co-combustion on combustion residues such as dry sorption residues and coarse ash in comparison with regular fuel. It can be seen that the concentrations of Hg (factor 2), Pb (factor 3) and Cd (factor 4) are increased in the mixture fly ash dry sorption residue. Also, the concentrations of Pb, Zn, Cu and Cr are increased in the coarse ash which makes material recovery impossible. However, leaching behaviour was not notably influenced.

	Dry sorption residues			
	Total content (mg/kg)		**Eluate content (mg/kg)**	
	Coal	**Co-firing of about 10 % sewage sludge**	**Coal**	**Co-firing of about 10 % sewage sludge**
Al	2.9	3.4 – 3.6	12	8.5 – 11
As	34	31 – 37	<0.2	<0.2
Cd	<2	4 – 7	<0.1	<0.1
Cr	49	55 – 64	0.91	0.81 – 0.85
Cu	135	80 – 140	<0.1	<0.1
Hg	0.6	0.6 – 1.3	<0.01	<0.01
Ni	91	93 – 100	<0.2	<0.2
Pb	230	228 – 650	<0.3	<0.3
Zn	140	245 – 570	<0.2	<0.2

Table 8.16: Effect of co-combustion on combustion residues
[64, UBA, 2000]

	Coarse ash			
	Total content (mg/kg)		Eluate content (mg/kg)	
	Coal	Co-firing of about 10 % sewage sludge	Coal	Co-firing of about 10 % sewage sludge
Al	4.4	4.8 – 5.9	21	8.8 – 133
As	11	11 – 13	<0.2	<0.2
Cd	<2	<2	<0.1	<0.1
Cr	59	86 – 260	0.11	<0.1 – 0.12
Cu	80	590 – 7800	0.1	0.1 – 0.23
Hg	<0.2	<0.2	<0.01	<0.01
Ni	70	130 – 290	<0.2	<0.2
Pb	57	130 – 3400	<0.3	<0.3 – 1.7
Zn	100	190 – 5590	<0.2	0.2 – 1.1

Table 8.17: Effect of co-combustion on combustion residues
[64, UBA, 2000]

Table 8.16 and Table 8.17 show that the possibility of mobilising the heavy metals in the residue from co-firing is generally relatively low due to the high temperatures in the boiler (vitrification effect).

Furthermore, the possibility of elution of the heavy metals is greatly reduced due to the compact nature of the residue after humidification. This is such that, relative to residues from conventional fuel (hard coal), no increase in concentrations in the eluate were detected, in particular where the product had been stabilised.

8.4 Techniques to consider in the determination of BAT for co-combustion of waste and recovered fuels

This section presents techniques that are considered in the determination of BAT for the prevention or reduction of emissions generated by co-combustion of secondary fuel. They are all currently commercially available. In this section the techniques to be considered have been described in a general way, but also refer back to previous sections on:

- applied processes and techniques (Section 8.1)
- assumptions regarding purification techniques (Section 8.1)
- examples of the co-combustion of secondary fuel (Section 8.2)
- effects of co-combustion on emissions and the quality of by-products (Section 8.3).

To avoid duplication throughout this document, refer to Environmental Management Systems (EMS) in Section 3.15.

8.4.1 Techniques for the storage and handling of dusty and odorous secondary fuel

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Transport of dusty and/or odorous fuel, such as sludge in enclosed or covered containers	Reduction of odorous and fugitive emissions	Possible	Possible	High			
Unloading of dusty and/or odorous fuel in enclosed unloading buildings e.g. equipped with suction devices that lead odorous air directly to the combustion chamber or burner, where it can be used as combustion air	Reduction of odorous and fugitive emissions	Possible	Possible	High			
Storage of dusty and/or odorous fuel in closed silos or bunkers	Reduction of odorous and fugitive emissions	Possible	Possible	High			
Application of suction plants and subsequent cleaning devices to silos, bunkers and hoppers storing sewage sludge. The odorous air can be led directly to the combustion chamber or burner, where it can be used as combustion air	Low emissions to the ambient air and low concentrations of methane inside the hoppers, thus reducing the risk of explosion	Possible	Possible	High			Without suction plants, the risk of explosion due to high concentrations of methane might be high. The production of methane might especially occur inside the hopper for the mechanically dried sludge due to it's high water content

Table 8.18: Techniques for the storage and handling of secondary fuel

8.4.2 Techniques for the pretreatment of secondary fuel

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Drying	Maintains the high performance of the boiler. Fuel containing high moisture can be used	Possible	Possible	High	Additional energy is needed for drying	Plant specific	Although the high moisture content of the fuel will affect the boiler performance negatively, it is still more economical to fire mechanically dried sewage sludge with high water contents in some cases as the thermal drying is also very costly and energy consuming. More information in the Waste Treatment BREF
Solar drying of sewage sludge	Low energy requirement	Possible	Possible	High	Tendency of odorous emissions	Plant specific	The required space should be available. More information in the Waste Treatment BREF
Pyrolysis	The impact of the secondary fuel on the performance of the boiler is diminished. A large variety of waste fuel can be used	Possible	Possible, but depends on design of the main boiler	Limited	Additional energy is needed for the pyrolysis reactor	Plant specific	Pyrolysis can be an attractive option for secondary fuel that cannot be ground in a (coal) mill to the required dimensions for co-combustion in a pulverised coal or lignite-fired power plant. This pretreatment is necessary to assure an adequate burnout in the boiler, due to the short residence time of the fuel in the furnace. More information in the Waste Incineration BREF
Anaerobic digestion	Methanisation of secondary fuel has several advantages as the products are easily fitted into the boiler. A large variety of waste fuel can be used	Possible	Possible	High		Plant specific	The secondary fuel needs to be biodegradable. The reactor operates at low temperatures with almost no corrosion. It is operated easily with ahigh water content More information in the Waste Treatment BREF
Gasification	Large quantities of secondary fuel with high concentrations of heavy metals (especially Hg) can be co-combusted after gasification and cleaning of the produced gas	Possible	Possible, but depends on design of the main boiler	Limited		Plant specific	More information in the Waste Treatment and Waste Incineration BREFs
Pre-combustion	Secondary fuel that cannot be combusted properly in pulverised coal-fired boilers						Waste incineration BREF needs to be consulted

Table 8.19: Techniques for the pretreatment of secondary fuel

8.4.3 Techniques to introduce secondary fuel into the combustion process

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Milling with the main fuel	An heterogeneous or poorly mixed fuel stream or an uneven distribution may influence the ignition and combustion in the boiler and has to be prevented	Possible	Limited	High			Mixing is only possible when the grinding behaviour of the main fuel and secondary fuel are more or less the same or when the amount of secondary fuel is very small compared to the main fuel flow
Use of separate lances	Large variety of secondary fuel in particular liquid fuel can be used	Possible	Possible	High	None	Not available	Separate lances are required for secondary fuel that cannot be mixed with the main fuel. Separate lances are also applied when the secondary fuel is used as reburn fuel in order to reduce NO_X emissions
Additional grate at the bottom of the boiler	Large variety of secondary fuel in particular biomass fuel can be used	Possible	Possible	Practised in new plants	None	Not available	
Special grate for secondary fuel	Large variety of secondary fuel in particular biomass fuel can be used	Possible	Very limited	Mainly practised in new plants	None	Not available	The installation of such a grate requires a lot of free space below the boiler, which is rarely available
Feeding of main and secondary fuel together	Good performance of the fluidised bed boiler	Possible	Possible	High	None	Not available	

Table 8.20: Techniques to introduce secondary fuel into the combustion process

8.4.4 Techniques for the prevention and control of air emissions by the co-combustion of secondary fuel

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
General Issues							
Careful selection of waste for co-combustion. Exact knowledge of their origin, their physico-chemical parameters and of their hazardous potential. Secondary fuel should be analysed periodically to check the quality of waste for co-incineration	Better knowledge of the secondary fuel helps to avoid unexpected peaks of pollutants and avoids damage of the boiler due to corrosion	Possible	Possible	High			The composition and properties of waste and biomass have to be determined comprehensively at the first delivery and can include the following parameters: name and address of the deliverer, mass, owner and origin of the waste, water and ash content, calorific value, content of chlorides, fluorides, sulphur and heavy metals
Limitation of the percentage of waste that will be co-combusted	Limitation of additional environmental impact	Possible	Possible	High		Plant specific	
Gasification	Large quantities of secondary fuel with high concentrations of heavy metals (especially Hg) can be co-combusted after gasification and cleaning of the produced gas.	Possible	Possible, but depends on design of the main boiler	Limited		Plant specific	More information in the Waste Treatment and Waste Incineration BREFs

Table 8.21: Techniques for the prevention and control of air emissions by the co-combustion of secondary fuel

Technique	Environmental benefit	Applicability		Operational experience	Cross-media effects	Economics	Remarks
		New plants	Retrofitable				
Particulate matter							Techniques that have been considered in the determination of BAT within the fuel specific chapters can also be considered when secondary fuel is co-combusted. However, the co-combustion of secondary fuel can lead to the following effects: • a change in the flue-gas volume and composition, with consequences for the heat transfer and flue-gas cleaning systems (e.g. deactivation of SCR catalyst by As, P, F and alkali metals), and interference with FGD systems • good and even combustion conditions have to be enabled (including flame stability, flame temperature, formation of an oxidative atmosphere at the surfaces of the boiler, prevention of the formation of 'strands') • emissions to the air (especially emissions of Hg, heavy metals, dioxins and furans, HCl, HF, unburned carbon, and CO) may be increased. In particular, when secondary fuel with a higher volatile metal contents (Hg) than in conventional fuel is used, the additional injection of activated carbon is a technique that should be considered in the determination of BAT
ESP	Reduction of dust and heavy metals	Possible	Possible	High		Plant specific	
Fabric filters	Reduction of dust and heavy metals	Possible	Possible	High			
SO_2							
Wet, semi dry or dry FGD techniques	Reduction of SO_2, HCl, HF dust and heavy metals	Possible	Possible	High		Plant specific	
NO_X							
Primary and/or secondary measures	Reduction of NO_X	Possible	Possible	High		Plant specific	
Heavy metals and others such as VOC and dioxins							
ESP or fabric filters, wet, semi-dry or dry FGD techniques and, as an additional option, the injection of activated carbon	Reduction of SO_2, HCl, HF dust and heavy metals (in particular Hg) as well as VOC and dioxin	Possible	Possible	High		Plant specific	
Note: To control air emission, also other techniques can be applied, therfoer references is given to the sections of the BREF describing the techniques available for solid, liquid fuel and gaseous fuels and in Chapter 3							

Table 8.22 Techniques for the prevention and control of air emissions by the co-combustion of secondary fuel

8.4.5 Techniques for the prevention and control of water pollution by the co-combustion of secondary fuel

Several techniques are considered to reduce the contamination of water:

- the common factor in all dewatering (drying) processes is that the water separated (filtrate or decant water) is polluted to different extents. This is particularly true for dewatering at higher temperatures and represents a weighty secondary pollution of the sewage treatment plant. The exhaust vapours and system off-gas resulting from the drying of sewage sludge can be led into the boiler for combustion
- the dust control with water of open fuel storage can result in waste water, if this water is not internally reprocessed, which is normally the case for coal storage. If secondary fuel is not stored and handled properly, rainwater may also be unnecessarily contaminated. 'Good housekeeping' can prevent substances being spilled and transferred to drains
- condensation techniques applied to plume conditioning produce large volumes of liquid for disposal, which can be contaminated by polluting substances and may require waste water treatment by neutralisation
- as liquors from wet scrubbing systems or condensates contain acid gas residues from the flue-gas, neutralisation is required before discharge to surface water or the public sewer. Settlement will be required if solid matter is present, and physico-chemical treatment may be necessary to remove other contaminants such as toxic metals
- clarified liquors could be returned to the fuel to eliminate discharges to water, but as the fuel moisture content is a key parameter for poultry litter in particular, this may not be feasible
- as described in Chapter 3, flue-gas desulphurisation is a main source of waste water, as it removes SO_2 as well as other pollutants, such as heavy metals, from the flue-gases. This waste water has to be treated in a waste water treatment facility before being discharged. The process has been described in Section 3.3.2. With good monitoring and constant optimisation of the process conditions, and possibly also the additional use of organic sulphide, higher inputs of heavy metals can be precipitated and filtrated in the waste water treatment facility to such a level that filtrate concentrations do not increase significantly. The quantity of the filtrate will not change with co-combustion.

8.4.6 Techniques to reduce the impact of co-combustion on the combustion residues and by-products

Some techniques may be applied to reduce the amount of waste generated by LCPs or reduce the impact of the waste produced by LCPs. The following list details techniques identified in this area:

- maintaining the quality of gypsum, ashes and slag to the same level as that occurring without the co-combustion of secondary fuel for the purpose of recycling. If co-combustion leads to significant (extra) disposal of by-products or residues, additional measures should be taken to avoid this
- basically the starting point for co-combustion is to prevent a decrease in the quality of combustion residues and by-products. This can be achieved by a pretreatment of the secondary fuel or by limiting the degree of co-combustion
- fly and bottom ashes produced by the process and disposed of to land on-site or off-site need to be handled and conveyed so as to prevent spillage, dust release or the generation of odours.

8.5 Best available techniques (BAT) for co-combustion of waste and recovered fuels

In understanding this section and its contents, the attention of the reader is drawn back to the preface of this document and in particular the fifth section of the preface: ‘How to understand and use this document’. The techniques and associated emission and/or consumption levels, or ranges of levels, presented in this section have been assessed through an iterative process involving the following steps:

- identification of the key environmental issues for the sector; which are emissions to air and water, thermal efficiency and combustion residues
- examination of the techniques most relevant to address those key issues
- identification of the best environmental performance levels, on the basis of the available data in the European Union and worldwide
- examination of the conditions under which these performance levels were achieved; such as costs, cross-media effects, main driving forces involved in the implementation of this techniques
- selection of the best available techniques (BAT) and the associated emission and/or consumption levels for this sector in a general sense all according to Article 2(11) and Annex IV of the Directive.

Expert judgement by the European IPPC Bureau and the relevant Technical Working Group (TWG) has played a key role in each of these steps and in the way in which the information is presented here.

On the basis of this assessment, techniques, and as far as possible emission and consumption levels associated with the use of BAT, are presented in this section that are considered to be appropriate to the sector as a whole and in many cases reflect current performance of some installations within the sector. Where emission or consumption levels ‘associated with best available techniques’ are presented, this is to be understood as meaning that those levels represent the environmental performance that could be anticipated as a result of the application, in this sector, of the techniques described, bearing in mind the balance of costs and advantages inherent within the definition of BAT. However, they are neither emission nor consumption limit values and should not be understood as such. In some cases, it may be technically possible to achieve better emission or consumption levels but due to the costs involved or cross-media considerations, they are not considered to be appropriate as BAT for the sector as a whole. However, such levels may be considered to be justified in more specific cases where there are special driving forces.

The emission and consumption levels associated with the use of BAT have to be seen together with any specified reference conditions (e.g. averaging periods).

The concept of ‘levels associated with BAT’ described above is to be distinguished from the term ‘achievable level’ used elsewhere in this document. Where a level is described as ‘achievable’ using a particular technique or combination of techniques, this should be understood to mean that the level may be expected to be achieved over a substantial period of time in a well maintained and operated installation or process using those techniques.

Where available, data concerning costs have been given together with the description of the techniques presented in the previous sections. These give a rough indication about the magnitude of costs involved. However, the actual cost of applying a technique will depend strongly on the specific situation regarding, for example, taxes, fees, and the technical characteristics of the installation concerned. It is not possible to evaluate such site-specific factors fully in this document. In the absence of data concerning costs, conclusions on economic viability of techniques are drawn from observations on existing installations.

It is intended that the general BAT in this section are a reference point against which to judge the current performance of an existing installation or to judge a proposal for a new installation. In this way they will assist in the determination of appropriate 'BAT-based' conditions for the installation or in the establishment of general binding rules under Article 9(8). It is foreseen that new installations can be designed to perform at, or even better than, the general BAT levels presented here. It is also considered that existing installations could move towards the general BAT levels or do better, subject to the technical and economic applicability of the techniques in each case.

While the BREFs do not set legally binding standards, they are meant to give information for the guidance of industry, Member States and the public on achievable emission and consumption levels when using specified techniques. The appropriate limit values for any specific case will need to be determined taking into account the objectives of the IPPC Directive and the local considerations.

To avoid duplication throughout this document, refer to BAT on Environmental Management System (EMS) in Section 3.15.1.

Depending on the type and the percentage of secondary fuels used for co-combustion, it should be noted that flue-gas volume and composition, the waste water, as well as the residues and by-products might be changed compared to the operation without co-combustion. The changes may have consequences on heat transfer and flue-gas cleaning systems (e.g. deactivation of SCR catalyst by As, P, F and alkali metals as well as interferences with the FGD operation), the waste water treatment plant and the way residues and by-products can be re-used. Good and even combustion conditions have to be enabled including flame stability, flame temperature, formation of an oxidative atmosphere at the surfaces of the boiler and prevention of formation of 'strands'. Emissions to the air especially emissions of heavy metals, in particular volatile metals such as Hg, but also dioxins and furans, HCl, HF, unburned carbon and CO can be increased.

The BAT conclusion in this section is, therefore, based on the concept that co-combustion of secondary fuel in large combustion plants should, according to the current EU legislation, not cause higher emissions of polluting substances in that part of the exhaust gas volume resulting from such co-combustion found in the incineration plants (see WI BREF). This can be achieved by careful selection of the type and mass flow (limitation of the percentage of secondary fuel that can be co-combusted) of the secondary fuel and by effective and appropriate flue-gas cleaning and waste water treatment techniques. For further legal requirements, reference is given to the dedicated EU Directive 2000/76/EC on the incineration of waste, with also deals with co-combustion[7] (co-incineration) of waste.

8.5.1 Acceptance and pre-acceptance criterias

BAT is to have complete pre-acceptance and acceptance criteria defined according to the BAT defined in the Waste Treatment BREF.

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[7] Annex II of the EU Directive 2000/76/EC provides the requirements on the determination of air emission limit values for the co-incineration of waste (co-combustion of secondary fuel).

8.5.2 Storage and handling of secondary fuel

For the storage, unloading and handling of secondary fuel the measures and techniques presented as BAT in the fuel specific chapters and in Section 8.4.1 are all considered to be BAT for the use of co-combustion to reduce fugitive emission of dust and odorous substances. In addition, the use of suction equipment and subsequent cleaning devices for closed facilities storing sewage sludge (including the possibility of leading the polluted suction air directly to the combustion chamber or burner, where it might be used as combustion air) has been considered as BAT due to the reduced risk of explosion. Concerning health and safety, the described measures to protect the workers need to be taken into account (reference is made to national health and safety regulations). Apart from this, the BAT conclusion laid down in the BREF on the storage of bulk and dangerous substances and the waste treatment BREF also needs to be taken into account during the storage and handling of secondary fuel.

8.5.3 Pretreatment of secondary fuel

For the pretreatment of secondary fuel, all the measures and techniques presented as BAT in the fuel specific chapters are generally considered to be BAT in order to ensure stable combustion conditions and to separate contaminants from the waste, in order that these waste materials can be used as secondary fuel. In addition, some pretreatment measures listed in Chapter 8.4.2 can be considered as BAT. However, it also needs to be noted, that the detailed information on BAT for pretreatment techniques of waste, including secondary fuel, will be described in the dedicated waste treatment and incineration BREFs.

8.5.4 Introduction of secondary fuel into the combustion process

For feeding secondary fuel into the combustion chamber (boiler), the measures and techniques presented in Section 8.4.3 are all considered to be BAT in order to ensure stable combustion conditions. However, the choice of the specific technique needs to be decided on a case-by-case basis according to the secondary fuel used. The spraying of liquid secondary fuel over the coal yard has not been considered as BAT because of the potential risk of water and groundwater contamination and due to the possibility of odorous emissions. Beside this, the spraying of liquid secondary fuel may increase the risk of self-ignition of the coal yard.

8.5.5 Air emissions

As mentioned at the end of the introduction to Section 8.5, the BAT conclusion in this section is based on the concept that co-combustion of secondary fuel in large combustion plants should, according to the current EU legislation, not cause higher emissions of polluting substances in that part of the exhaust gas volume resulting from such co-combustion found in the incineration plants (see WI BREF). At this point, it is necessary to mention that plants co-combusting waste have to meet the requirements of the dedicated Waste Incineration Directive (EU Directive 2000/76/EC).

Large combustion plants, designed and operated according to BAT as defined in this BREF document operate effective techniques and measures for the removal of dust (including partly heavy metals), SO_2 NO_X, HCl and HF. In general, these techniques can be seen as sufficient and can, therefore, also be considered as BAT for the co-combustion of secondary fuel. The basis for this are the BAT conclusions and, in particular, the emission levels associated with the use of BAT as defined in the fuel specific chapters. Higher input of these pollutants into the firing system can be balanced within certain limits by adaptation of the flue-gas cleaning system and will normally not lead to higher emissions. Input of chlorinated compounds is also limited by the power plant operator to prevent high temperature corrosion.

The rationale as to which wastes can be used for co-combustion is based on the specifications of the conventional fuel normally burned in the specific plant and its associated measured emission levels. If the range of impurities of the waste, in particular the content of heavy metals, lies within the same range as that from the normally used conventional fuel, the fuel specific BAT applies also for the co-combustion of this secondary fuel. The first BAT choice in this respect is also the careful selection of the type and mass flow of the secondary fuel, together with limiting the percentage of the secondary fuel that can be co-combusted. The following measures should be taken into account in this sense:

- screening secondary fuel according to acceptance criteria for critical parameters (see BAT for acceptance and pre-acceptance criterias). These are heating value, water content, ash content, chlorine and fluorine content, sulphur content, nitrogen content, PCB, metals (volatile (Hg, Tl, Pb, Co and Se) and non-volatile (e.g. V, Cu, Cd, Cr, Ni)) and phosphorus and alkaline content (when use animal by-products)
- limiting the co-combustion rate of most polluted secondary fuel
- pretreating the SF
- avoiding Hg entering as an elevated component of the secondary fuel
- using gasification of the secondary fuel and cleaning of the produced gas when there are large quantities of secondary fuel with high concentrations of heavy metals (especially Hg) to be used in the LCP
- avoiding the introduction of chlorine compounds into the secondary fuel.

However, according to the waste used the co-combustion of secondary fuel can, as already explained, lead to increased emissions of heavy metals, in particular mercury, as well as to the emission of VOCs, halides and sometimes dioxins. In this case the adaptation of flue-gas cleaning systems and the additional injection of activated carbon with an associated reduction rate of 70 - 85 % is regarded as BAT.

The co-combustion of secondary fuel typically lead to a loss of thermal efficiency. In this context, it should be taken into account that the main purpose of the power plant is the generation of energy rather than the thermal treatment of waste. A lost of thermal efficiency is only justified if it is balanced with less emissions of pollutants.

8.5.6 Water pollution

For the co-combustion of secondary fuel the measures and techniques presented as BAT in the fuel specific chapters and in Section 8.4.5 are all considered to be BAT in order to avoid an additional contamination of water and groundwater sources by the co-combustion of secondary fuel. In this respect, the proper storage and handling of secondary fuel as described earlier will help to achieve this aim. ‘Good housekeeping’ will prevent substances being spilled and transferred to drains.

Because secondary fuel may contain higher levels of heavy metals and other substances, such as halides etc., BAT is to treat this waste water before it is discharged. The process has been described in Section 3.10. With good monitoring and constant optimisation of the process conditions, possibly also with the additional use of organic sulphide, higher inputs of heavy metals can be precipitated and filtrated in the waste water treatment facility to such a level that effluent concentrations do not increase significantly. The quantity of the effluent will not change with co-combustion.

8.5.7 Combustion residues and by-products

In the co-combustion of secondary fuel the measures and techniques presented as BAT in the fuel specific chapters and in Section 8.4.6 also are all considered to be BAT for the co-combustion of secondary fuel. The main BAT issue is maintaining the quality of gypsum, ashes and slag and other residues and by-products at the same level as those occurring without the co-combustion of secondary fuel for the purpose of recycling. If co-combustion leads to significant (extra) disposal volumes of by-products or residues or extra contamination by metals (e.g. Cr, Pb, Cd) or dioxins, additional measures need to be taken to avoid this. One additional measure to consider is to restrict co-combustion to waste fractions with pollutant concentrations similar to primary fuels (e.g. heavy metals, Cl etc.).

8.6 Emerging techniques for the co-combustion of waste and recovered fuels

It is expected that in the future, due to the extra experience being gained with pretreatment and abatement techniques, that the degree of co-combustion will be increased above the level of 10 % on a thermal basis.

9 CONCLUDING REMARKS

This chapter deals with the timing of the work; sources, availability and quality of information; the degree of consensus amongst experts of the TWG; and recommendations for future work.

9.1 Timing of the work

The work on combustion installations with a rated thermal input exceeding 50 MW, the so-called BREF on large combustion plants, or 'LCP BREF' started on 24 – 25 February 2000 with the kick-off meeting of the TWG. Two drafts were issued to the Technical Working group (TWG) for consultation. The first draft was issued in March 2001 and the second draft was issued in March 2003. In both consultation periods, new information and comments were submitted.

The final TWG meeting was held on 18 – 21 November 2003. There was mainly support for the techniques considered as BAT. However some issues, in particular the emission levels associated with the use of BAT, were strongly debated. New information and comments submitted during the meeting and information on the split view rationales have been incorporated into the final draft.

9.2 Sources of information

As sources of information, a large number of documents, reports and information from industry, EU Member States, operators and authorities as well as from suppliers of equipment and environmental NGOs have been used to draft the document. Other information submitted was more focused on a particular environmental issue, where the emphasis was largely on emissions to air and water as well as about the possibilities of increasing efficiencies and thus reducing the emission of CO_2. Information was further obtained during site visits in different European Member States and by personal communication on the selection of technology and on experiences with the application of reduction techniques.

To support the work, some Member States and industry conducted or commissioned studies aimed at a more integrated description of BAT.

There is good information available on reduction measures for emissions to air reflecting the worldwide efforts to reduce long distance transboundary air pollution.

During the work, it became evident that there was plenty of information from different sources and qualified plant specific emission data were presented in different ways. Sometimes in the technical background material, the environmental performance of primary and secondary measures are described somewhat vaguely. Plant specific information and qualified figures for good performances have been difficult, and sometimes even impossible, to obtain. It has to be noted that often insufficient information was given for submitted data on sampling and analysis methods. Reference time intervals (e.g. daily or yearly average values), computation methods and reference conditions were often missing or incomplete. Therefore, the comparability of environmental performance data varies and needs to be improved in the future.

In order to improve the comparability it is recommended that an European survey is carried out on how environmental performance data of combustion plants are compiled, whether or not the different practices are relevant, and if so, to what extent, and in what respect. Calculations and reports on energy efficiency on a comparable level could also benefit from such a survey. It was not always clear which waste materials were included or excluded when figures about the amount of solid waste, residues and by-products were submitted.

Sufficiently qualified cost data that are reliable, transparent and which allow the linking of techniques with costs and savings are still missing. Cost data are very specific to the local conditions and can only be calculated for the individual circumstances of a plant and therefore exact comparisons are not possible. Costs vary considerably between plants when operating the same technique, e.g. due to different technical starting points and different timings for plant investments. There are some cost data available but, in general, it is not known what exactly is included in the figures or how they are calculated. Therefore, data in the BREF can only give a good guidance of the order of magnitude of such costs.

9.3 Degree of consensus

This BREF as a whole has a lot of support from the TWG Members. However, Eurelectric and Euromot – two representatives of the industry – and a few Member States did not express their full support for this final draft and contested with so-called ‘split views’ to some of the BAT conclusions presented in this document. Their main reasons for this are given below.

A few of the Member States and Eurelectric expressed their view that the ELVs defined in the European Directive on Large Combustion Plants (Directive 2001/80/EG) should be adopted as the upper end of the range for emissions associated with BAT. Eurelectric contested that the ranges given as emission levels associated with the use of BAT are, in general, too low for both new and existing power plants. However, it should be noted that the upper levels of BAT associated emission levels, in particular for existing plants, are similar to some current ELVs set in some European Member States. This supports the TWG Members view that BAT levels is reasonable and illustrates that the considered BAT levels are already being achieved by a good number of plants in Europe.

Another point of disagreement is that Eurelectric and a few Member States contested that the economic viability in the determination of certain BATs has not been sufficiently taken into account. This emphasizes the fact that there was not sufficient information provided by the TWG experts on this issue. Well-founded information on cost data for the application of secondary measures for large combustion plants was not provided and it is thus unclear which yardstick to use for a full consideration of costs. Generally, it can be stated that the specific costs for retrofitting existing combustion plants are relatively higher than for new plants because the material or layout of older equipment might not fit. Usually the specific cost for smaller plants are higher than for larger ones.

Notwithstanding the above arguments, Eurelectric and one Member State took the view that the economic difference between new/existing and large/small ‘large combustion plants’ had not been sufficiently considered and that clear differences should have been established in the BREF. Moreover, it was also stated that not enough consideration was given to problems for plants operating only partly as peak load plants.

Part of industry has provided extensive information for this document, but cannot agree that the final document adequately reflect the extensive experiences of its members in both building and retrofitting abatement equipment to LCPs. In their view, it does not consider that the document sufficiently addresses what is practical and achievable for all plants across the sector.

The whole debate also highlights the different understandings of BAT as defined in the IPPC-Directive and emphasises the need to read the BREF in the light of the preface to the document. Apart from these general issues, there are also a few specific issues where the final conclusions did not receive unanimous support.

9.4 Recommendations for future work

The generation of energy is an essential element in today's industrial society and any industrial process. The assessment of best available techniques for large combustion plants has therefore gained great interest of Member States, of industry and of environmental NGOs.

Especially during the last two decades, substantial investments and modifications at power plants have been carried out in many European countries. The impact of fossil fuel combustion on the environment as a whole could be reduced substantially through the use of primary as well as secondary measures. However, improvements and efforts still have to be made in order to achieve the long-term aim of sustainability. So far, legislation and control by environmental authorities have mainly focused on air and water emissions. Regulations and enforcements have been important driving forces for the improvements that have been achieved so far. However, not only authorities but also industry itself, investors, customers, the general public including political groups, environmental NGOs, and media are participating as stakeholders, demanding that plants reduce their environmental impact.

Within the Technical Working Group, there clearly is agreement that BAT for large combustion plants is an approach within which a number of specific techniques can be identified. It is a complex issue involving thermodynamic principles and interaction with the characteristics of the combustion process. It is clear that the performance for large combustion plants is dependent upon the plant design and operation, the cooling system and the costs.

BAT approach is developed with the emphasis on prevention of pollution by technological changes and improving operating practice. This approach makes a distinction between new and existing plants, but in this document, it is emphasised that reduction measures in existing plants have the same objective. In other words, the same approach applies, but options for reduction are more limited in existing plants. The process of exchange of information has made it possible to identify a number of techniques that can be considered BAT on a general level, as presented in Chapters 4 to 8.

Concerning the environmental issues associated with the operation of large combustion plants in the scope of this document, emphasis is largely given on reduction of emissions to air. Not enough data were reported that are considered as representative and a survey is recommended to be able to get a better picture, which could then serve as a benchmark for the performance of emission reduction techniques. Further investigations for available data will be needed.

While the TWG recognised that the document focuses on installations above 50 MW and considered installations with multiple units (each of them being smaller than 50 MW), it did not focus its attention on individual small units as such. This characteristic can be addressed at a local level under the Art 9(4) but it will be useful in the future review of this BREF to pay more attention to this issue.

When emission data are reported in future, it is advised to report this in a consistent way including specific volumes and concentrations, and reference conditions (e.g. mg/Nm^3, tonne/MJ, O_2 %) of pollutants to air and waste water, so that specific emissions can be better benchmarked and understood by readers. Sufficiently qualified specific emission data are the preferred information for comparison of the environmental performance of various combustion installations across Europe. In addition, it is highly advisable to include BAT based emissions levels for N_2O as well as techniques for the reduction of N_2O in the next revision of the document.

The same is true for potential soil contamination (e.g. environmentally sound decommissioning of plants, prevention of hazardous substances escaping during storage, transportation and use) and health and safety aspects. If information is available, this could be incorporated in the BREF review.

At present, only limited or insufficiently qualified information on costs and/or savings on BAT has emerged from the exchange of information in the Technical Working Group. However, it is recommended the collection of more detailed cost data and following international work on this (e.g. EGTEI, Expert group on techno-economic issues) in a future information exchange should be undertaken. This should include information on specific costs and savings such as amortisation time of measures, and unit costs.

Before an update of this BREF is carried out, Member States and industry should make information on emissions and energy consumption, together with associated techniques and their costs, more readily available and transparent. An important step to support this work would be if Member states and industry openly publish data for each large combustion plant. In this respect, it could be useful to start with a survey on different practices in determining environmental performance and reporting results of European large combustion plants.

A number of techniques were identified and considered BAT, but some are still in a stage of development and may be considered as emerging. Their application and environmental consequences still have to be assessed. The section ‘emerging techniques’ in all chapters gives some examples of promising techniques, which have all reached a different status of development. Some of these new technologies have recently been introduced in the sector. This is true, for instance, for CCGT plants achieving up to 60 % efficiency.

Another point to consider is to differ between heavy fuel oil (HFO) and light fuel oil (LFO), as combustion of these fuels lead to big differences on achievable emission levels (dust, heavy metals, SO_2 and NO_x) as well as the related necessary technical measures to obtain these levels. It is noticed that the specific conditions and requirements when firing high-sulphur coal in large combustion plants has not been properly addressed.

A number of full-scale plants are going to come into operation. It is expected that, within a few years, results from long term trials will be available from various large combustion plants. These experiences could be incorporated when reviewing the BREF and other relevant emerging techniques could be added.

The EC is launching and supporting, through its RTD programmes, a series of projects dealing with clean technologies, emerging effluent treatment and recycling technologies and management strategies. Potentially these projects could provide a useful contribution to future BREF reviews. Readers are therefore invited to inform the EIPPCB of any research results which are relevant to the scope of this document (see also the preface of this document).

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GLOSSARY

GENERAL TERMS AND SUBSTANCES

TERM	MEANING
acid	proton donor. A substance that, more or less readily, gives off hydrogen ions in a water solution.
activated sludge process	a sewage treatment process by which bacteria that feed on organic wastes are continuously circulated and put in contact with organic waste in the presence of oxygen to increase the rate of decomposition.
aeration	the act of mixing a liquid with air (oxygen).
alkali	proton acceptor. A substance that, more or less readily, takes up hydrogen ions in a water solution.
anaerobic	a biological process which occurs in the absence of oxygen.
biodegradable	that can be broken down physically and/or chemically by micro-organisms. For example, many chemicals, food scraps, cotton, wool and paper are biodegradable.
Brayton cycle	see Annex 10.1.3.
Carnot cycle	see Annex 10.1.1.5.
Cheng cycle	see Section 7.1.6.
Claus plant	sulphur recovery unit. For more information refer to the Refinery BREF.
cross-media effects	the calculation of the environmental impacts of water/air/soil emissions, energy use, consumption of raw materials, noise and water extraction (i.e. everything required by the IPPC Directive).
diffuse emission	emissions arising from direct contact of volatile or light dusty substances with the environment (atmosphere, under normal operating circumstances). These can result from: • inherent design of the equipment (e.g. filters, dryers, etc…) • operating conditions (e.g. during transfer of material between containers) • type of operation (e.g. maintenance activities) • or from a gradual release to other media (e.g. to cooling water or waste water). Fugitive emissions are a subset of diffuse emissions.
diffuse sources	sources of similar diffuse or direct emissions which are multiple and distributed inside a defined area.
dolomite	type of limestone, the carbonate fraction of which is dominated by the mineral dolomite, calcium magnesium carbonate ($CaMg(CO_3)$).
effluent	physical fluid (air or water together with contaminants) forming an emission
emerging techniques	name of a standard chapter in BREFs
emission	the direct or indirect release of substances, vibrations, heat or noise from individual or diffuse sources in the installation into the air, water or land
emission and consumption levels associated with the use of BAT	see generic introduction to BAT sections
emission limit values	the mass, expressed in terms of certain specific parameters, concentration and/or level of an emission, which may not be exceeded during one or more periods of time.
'end-of-pipe' technique	a technique that reduces final emissions or consumptions by some additional process but does not change the fundamental operation of the core process. Synonyms: 'secondary technique', 'abatement technique'. Antonyms: 'process-integrated technique', 'primary technique' (a technique that in some way changes the way in which the core process operates thereby reducing raw emissions or consumptions).
existing installation	an installation in operation or, in accordance with legislation existing before the date on which the Directive is brought into effect, an installation authorised or in the view of the competent authority the subject of a full request for authorisation, provided that that installation is put into operation no later than one year after the date on which IPPC Directive is brought into effect.

TERM	MEANING
fugitive emission	emission caused by non-tight equipment/leak: emission into the environment resulting from a gradual loss of tightness from a piece of equipment designed to contain an enclosed fluid (gaseous or liquid), basically caused by a difference of pressure and a resulting leak. Examples of fugitive emissions: leak from a flange, a pump, sealed or tightened equipment, etc…
immission	occurrence and level of polluting substance, odour or noise in the environment.
installation	a stationary technical unit where one or more activities listed in Annex I of the IPPC Directive are carried out, and any other directly associated activities which have a technical connection with the activities carried out on that site and which could have an effect on emissions and pollution.
Lurgi CFB	particular SO_x and NO_X reduction process.
monitoring	process intended to assess or to determine the actual value and the variations of an emission or another parameter, based on procedures of systematic, periodic or spot surveillance, inspection, sampling and measurement or other assessment methods intended to provide information about emitted quantities and/or trends for emitted pollutants.
multi-media effects	see *cross-media effects.*
naphthenes	hydrocarbons containing one or more saturated rings of 5 or 6 carbon atoms in their molecules, to which paraffinic-type branches are attached (adjective: napthenic).
operator	any natural or legal person who operates or controls the installation or, where this is provided for in national legislation, to whom decisive economic power over the technical functioning of the installation has been delegated.
Otto cycle	four stroke engine.
pollutant	individual substance or group of substances which can harm or affect the environment.
primary measure/technique	a technique that in some way changes the way in which the core process operates thereby reducing raw emissions or consumptions (see '*end-of-pipe technique'*)
Rankine cycle	see Annex 10.1.2.
secondary measure/technique	see '*end-of-pipe technique'*
specific emission	emission related to a reference basis, such as production capacity, or actual production (e.g. mass per tonne or per unit produced).
spinning reserve	excess power capacity.
Thermie programme	EC energy programme.

LIST OF ABBREVIATIONS

Abbreviation	Meaning
AF	arch-fired
AFBC	atmospheric fluidised bed combustion
AFBG	atmospheric circulating fluidised bed gasifier
AGR	advanced gas reburn
AOX	adsorbable organic halogen compounds. The total concentration in milligrams per litre, expressed as chlorine, of all halogen compounds (except fluorine) present in a sample of water that are capable of being adsorbed on activated carbon.
API	American Petroleum Institute
ASTM	classification developed in the US for coal
BAT	best available techniques
BBF	biased burner firing
BFB	bubbling fluidised bed
BFBC	bubbling fluidised bed combustion
BFG	blast furnace gas
BOD	biochemical oxygen demand: the quantity of dissolved oxygen required by micro-organisms in order to decompose organic matter. The unit of measurement is mg O_2/l. In Europe, BOD is usually measured after 3 (BOD_3), 5 (BOD_5) or 7 (BOD_7) days.
BOOS	burner out of service
BREF	BAT Reference document
BTEX	benzene, toluene, ethylbenzene, xylene
CC	combined cycle
CCGT	combined cycle gas turbine
CCP	coal combustion products
CEC	California Energy Commission
CEM	continuous emission monitoring
CEMS	continuous emission monitoring system
CETF	combustion and environmental test facility
CFB	circulating fluidised bed
CFBC	circulating fluidised bed combustion
CHAT	cascade humidified air turbine
CHP	combined heat and power (co-generation)
CIS	countries from the ex-soviet union
COD	chemical oxygen demand: the amount of potassium dichromate, expressed as oxygen, required to chemically oxidise at approx. 150 °C substances contained in waste water.
daf	dry and ash free basis
DBB	dry bottom boiler
DENOX	denitrification
DESONOX	a particular SO_X and NO_X reduction technique
DESOX	a desulphurisation technique
DF	dual fuel
DH	district heating
DLE	dry low emission premix combustion chamber for gas turbines
DLN	dry low-$NO_{X,}$ e.g. DLN burner
DLN	dry low-NO_X premix combustion chamber for gas turbines
DM/dm	dry matter
DS/ds	dry solids content. The mass of a material remaining after drying by the standard method of test.
DS burner	drall swirl burner
DSI	direct sorbent injection
DWI	direct water injection
EDTA	ethylenediamine tetraacetic acid
EIPPCB	European IPPC Bureau
EGR	exhaust gas recirculation
ELV	emission limit value

EMAS	European Community Eco-Management and Audit Scheme
EMS	environment management system
EO	energy output
EOR	enhanced oil recovery
EOP	end-of-pipe
EOX	extractable organic halogens
EPER	European pollutant emission register
ESP	electrostatic precipitator
EUF	energy utilisation factor
EUR	EURO – common unit of currency in many EU-15 countries
EU-15	15 Member States of the Euopean Union
FBC	fluidised bed combustion
FBCB	fluidised bed combustion boiler
FF	fabric filter
FEGT	furnace exit gas temperature
FGC	flue-gas clean-up
FGD	flue-gas desulphurisation
FRB	coal classification developed in the UK
FGR	flue-gas reburn
GDP	gross domestic product
GF	grate firing
GRP	glass reinforced plastic
GT	gas turbine
GTCC	gas turbine combined cycle
GWP	global warming potential
HAT	humidified air turbine
HFO	heavy fuel oil
Hardgrove Grindability Index (HGI)	number to define the hardness of coal.
HHV	higher heating value
Hu	lower heating value
HRSG	heat recovery steam generator
HP	high pressure
IEA	International Energy Agency
IEF	Information exchange forum (informal consultation body in the framework of the IPPC Directive).
IEM	Internal electricity market (Directive (96/92/EC)
IGCC	integrated gasification combined cycle
IPC	UK integrated pollution control law
IPPC	integrated pollution prevention and control
IPP	independent power producers
I-TEQ	unit of the dioxin concentration based on toxicity aspects
JBR	jet bubbling reactor
JRC	Joint Research Centre
LCP	large combustion plant
LFO	light fuel oil (lighter than HFO)
LHV	lower heating value
LNB	Low NO_X burner
LOI	loss-on-ignition
LP	low pressure
LPGs	liquid petroleum gas
LVOC	large volume organic chemicals (BREF)
LIMB	limestone injection multistage burner
MCR	micro carbon residue
MDF	middle-density fibre board
MEA	monoethanolamine
MMBtu	Million of Btu (British thermal unit)
MP	medium pressure
n.a.	not applicable OR not available (depending on the context).
n.d.	no data.

NMHC	non-methane hydrocarbons
NMVOC	non-methane volatile organic compounds
NOXSO	combined technique for the reduction of NO_X and SO_X. More information in Section 3.5.1.2
OECD	Organisation for Economic Co-operation and Development
OFA	overfire air
PAH	polyaromatic hydrocarbons
PC	pulverised combustion
PAC	powdered activated carbon
PFBC	pressurised fluidised bed combustion
PCB	polychlorinated benzenes
PCDD	polychlorinated-dibenzo-dioxins
PCDF	polychlorinated-dibenzo-furans
PEMS	parametric emission modelling system
PFF	polishing fabric filter
PI	process-integrated
Pm	primary measures
PM (PM_{10} and $PM_{2.5}$)	particulate matter
POM	particulate organic matter
POPs	persistent organic compounds
PPFBC	pressurised fluidised bed combustion
PRV	pressure reducing value
PSA	pressure swing adsorption
QF	quality factors
RDF	refuse derived fuel
REF	recovered fuel
R&D	research and development
SC	spray cooling
SCONOX	particular NO_X reduction process for gas turbines
SCR	selective catalytic reduction
SD	spray dryer
SDA	spray dry absorber
SDS	spray dry scrubber
SS	suspended solids
SF	secondary fuel
SG	steam generator
SME	small to medium sized enterprise
SNCR	selective non catalytic reduction
SNRB	Combined SO_x-NO_X reduction technique ROX-Box process
SRU	sulphur recovery unit
STIG	steam injected gas
SWTP	seawater treatment plant
TDS	total dissolved solids
TEF	toxic equivalency factor
TEQ	toxic equivalent quantity
TOPHAT	humidified air turbine where the air is injected in the compressor
TS	total solids
TSA	thermal swing adsorption
TSS	total suspended solids
TWG	technical working group
UHC	unburned hydrocarbons
UHV	upper heating value
ULNTF	ultra low NO_X tangential firing
UN ECE	United Nations Economic Commission for Europe
USEPA	United States Environment Protection Agency
VGB	Vereinigung der Großkrftwerksbetreiber
VI	viscosity index
VOCs	volatile organic compounds
waf	water free
WSA SNOX	a particular SO_x and NO_X reduction process

WBB	wet bottom boiler
WHB	waste heat boiler
WHRU	waste heat recovery unit
WI	waste incineration (typically refers to WI BREF)
WS	whirl-swirl
WT	waste treatment (typically refers to WT BREF)
WWTP	waste water treatment plant

LIST OF COUNTRIES AND CURRENCIES

(Situation at 26.6.2002)

MEMBER STATES LIST

Short Name	Full Name	Abbreviation[1]	Currency[2]	Currency ISO Code[3]
Austria	Republic of Austria	A	Euro	EUR
Belgium	Kingdom of Belgium	B	Euro	EUR
Cyprus	Republic of Cyprus	CY	Cyprus pound	CYP
Czech Republic	Czech Republic	CZ	Czech koruna (pl. koruny)	CZK
Estonia	Republic of Estonia	EE	Estonian kroon (pl. krooni)	EEK
Germany	Federal Republic of Germany	D	Euro	EUR
Denmark	Kingdom of Denmark	DK	Danish krone (pl. kroner)	DKK
Spain	Kingdom of Spain	E	Euro	EUR
Greece	Hellenic Republic	EL	Euro	EUR
France	French Republic	F	Euro	EUR
Finland	Republic of Finland	FIN	Euro	EUR
Hungary	Republic of Hungary	HU	forint (inv.)	HUF
Italy	Italian Republic	I	Euro	EUR
Ireland	Ireland	IRL	Euro	EUR
Latvia	Republic of Latvia	LV	lats (pl. lati)	LVL
Lithuania	Republic of Lithuania	LT	litas (pl. litai)	LTL
Luxembourg	Grand Duchy of Luxembourg	L	Euro	EUR
Malta	Republic of Malta	MT	Maltese lira	MTL
Netherlands	Kingdom of the Netherlands	NL	Dutch Guilder; Euro	NLG; EUR
Poland	Republic of Poland	PL	Zloty	PLN
Portugal	Portuguese Republic	P	Euro	EUR
Slovakia	Slovak Republic	SK	Slovak koruna (pl. koruny)	SKK
Slovenia	Republic of Slovenia	SI	Tolar	SIT
Sweden	Kingdom of Sweden	S	Swedish krona (pl. kronor)	SEK
United Kingdom	United Kingdom of Great Britain and Northern Ireland	UK	pounds sterling	GBP

1. In BREFs, list Member States in English alphabetical order, using these abbreviations decided by the Permanent Representations
2. Former Currencies (pre-euro):
   - Austria - Austrian schilling (ATS)
   - Belgium - Belgian franc (BEF)
   - Germany - German mark (DEM)
   - Spain - Spanish peseta (ESP)
   - Greece - Greek drachma, pl drachmae (GRD)
   - France - France franc (FRF)
   - Finland - Finnish markka, pl. markkaa (FIM)
   - Italy - Italian lira, pl. lire (ITL)
   - Ireland - Irish pound (punt) (IEP)
   - Luxembourg – Luxembourg franc (LUF)
   - Portugal - Portuguese escudo (PTE)
3. ISO 4217, as recommended by Secretariat-General (SEC(96) 1820).

EU ENLARGEMENT CANDIDATE COUNTRIES

Short Name	**Full Name**	**Country ISO Code**[1]	**Currency**	**Currency ISO Code**[2]
Bulgaria	Republic of Bulgaria	BG	lev (pl. leva)	BGN
Romania	Romania	RO	Romanian leu (pl. lei)	ROL
Turkey	Republic of Turkey	TR	Turkish lira	TRL

SOME OTHER COUNTRIES

Short Name	**Full Name**	**Country ISO Code**[1]	**Currency**	**Currency ISO Code**[2]
Australia	Commonwealth of Australia	AU	Australian dollar	AUD
Canada	Canada	CA	Canadian dollar	CAD
Iceland	Republic of Iceland	IS	Icelandic krona (pl. kronur)	ISK
Japan	Japan	JP	yen (inv.)	JPY
New Zealand	New Zealand	NZ	New Zealand dollar	NZD
Norway	Kingdom of Norway	NO	Norwegian krone (pl. kroner)	NOK
Russia	Russian Federation	RU	new rouble; Russian rouble	RUB; RUR
Switzerland	Swiss Confederation	CH	Swiss franc	CHF
United States	United States of America	US	US dollar	USD

1. ISO 3166
2. ISO 4217

The full list (of all countries) can be found online in the Interinstitutional Style Guide at
http://eur-op.eu.int/code/en/en-5000500.htm

COMMON UNITS, MEASUREMENT AND SYMBOLS

TERM	MEANING
atm	normal atmosphere (1 atm = 101325 N/m^2)
bar	bar (1.013 bar = 1 atm)
Bq	becquerel (s^{-1}) – activity of a radionuclide
°C	degree Celsius
cm	centimetre
cSt	centistokes = 10^{-2} stokes
d	day
g	gram
GJ	gigajoule
GW	gigawatt
GWh	gigawatt hours. Note also TWh, MWh, kWh
GWh_e	gigawatt hours electical. Note also TWh_e, MWh_e, kWh_e
Hz	hertz
h	hour
J	joule
K	kelvin (0 °C = 273.15 K)
kcal	kilocalorie (1 kcal = 4.19 kJ)
kg	kilogram
kJ	kilojoule (1 kJ = 0.24 jkcal)
kPa	kilopascal
kt	kilotonne
kWh	kilowatt-hour (1 kWh = 3600 kJ = 3.6 MJ)
l	litre
m	metre
m^2	square metre
m^3	cubic metre
mg	milligram (1 mg = 10^{-3} gram)
MJ	megajoule (1 MJ = 1000 kJ = 10^6 joule)
mm	millimetre (1 mm = 10^{-3} m)
m/min	metres per minute
Mt	megatonne (1 Mt = 10^6 tonne)
MW_e	megawatts electric (energy)
MW_{th}	megawatts thermal (energy)
ng	nanogram (1 ng = 10^{-9} gram)
Nm^3	normal cubic metre (101.325 kPa, 273 K)
Pa	pascal
ppb	parts per billion
ppm	parts per million (by weight)
ppmvd	parts per million in volume for dry gases
°R	degree rankine
s	second
t	metric tonne (1000 kg or 10^6 gram)
T-s	temperature-entropy
t/yr	tonne(s) per year
V	volt
vol-%	percentage by volume. (Also % v/v)
wt-%	percentage by weight. (Also % w/w)
yr	year
~	around; more or less
ΔT	temperature difference (increase)
µm	micrometre (1 µm = 10^{-6} m)

LIST OF CHEMICAL ELEMENTS

NAME	SYMBOL	NAME	SYMBOL
antimony	Sb	praseodymium	Pr
arsenic	As	promethium	Pm
astatine	At	protactinium	Pa
barium	Ba	radium	Ra
beryllium	Be	radon	Rn
boron	B	rhenium	Re
bromine	Br	rhodium	Rh
cadmium	Cd	rubidium	Rb
calcium	Ca	ruthenium	Ru
carbon	C	rutherfordium	Rf
chlorine	Cl	samarium	Sm
chromium	Cr	scandium	Sc
cobalt	Co	selenium	Se
copper	Cu	silicon	Si
fluorine	F	silver	Ag
helium	He	sodium	Na
hydrogen	H	strontium	Sr
iodine	I	sulphur	S
iron	Fe	tantalum	Ta
lead	Pb	technetium	Tc
magnesium	Mg	tellurium	Te
manganese	Mn	terbium	Tb
neon	Ne	thallium	Tl
nickel	Ni	thorium	Th
niobium	Nb	thulium	Tm
nitrogen	N	tin	Sn
nobelium	No	titanium	Ti
osmium	Os	tungsten	W
oxygen	O	uranium	U
palladium	Pd	vanadium	V
phosphorus	P	xenon	Xe
platinum	Pt	ytterbium	Yb
plutonium	Pu	yttrium	Y
polonium	Po	zinc	Zn
potassium	K	zirconium	Zr

SI UNIT PREFIXES

Symbol	Prefix	Term	Number
E	exa	10^{18}	1 000 000 000 000 000 000
P	peta	10^{15}	1 000 000 000 000 000
T	tera	10^{12}	1 000 000 000 000
G	giga	10^{9}	1 000 000 000
M	mega	10^{6}	1 000 000
k	kilo	10^{3}	1000
h	hecto	10^{2}	100
da	deca	10^{1}	10
-----	-----	1 unit	1
d	deci	10^{-1}	0.1
c	centi	10^{-2}	0.01
m	milli	10^{-3}	0. 001
µ	micro	10^{-6}	0.000 001
n	nano	10^{-9}	0.000 000 001
p	pico	10^{-12}	0.000 000 000 001

10 ANNEXES

10.1 Annex 1: Principles of combustion cycles and efficiency concepts

To assist public understanding of the BREF, this annex gives a short explanation of the principles and concepts of combustion cycles, as this is the theory on which power plant technology and large combustion installation design and techniques are based [54, Cortés and Plumed, 2000]. For more detailed information on the theory thermodynamic cycles of fossil fuel combustion and energy generation, it is recommended that the reader consults the following references which have been used as background material for this part of the document [55, Çengel and Boles, 1994], [56, Rogers and Mayhew, 1967], [53, El-Wakil, 1984], [50, Korobitsyn, 1998], [58, Eurelectric, 2001], [80, Siemens, 2000], [49, Electrabel, 1996].

10.1.1 Annex 2: Thermodynamic principles

10.1.1.1 First law of thermodynamics

Thermodynamics is a branch of physics in which the concept of energy related concepts and their properties are studied. As is usually the case in physics, thermodynamics is based on induction: the laws which describe the behaviour of energy, have been formulated on the basis of observations of reality. These are called the laws of thermodynamics.

According to the first law, energy is always conserved; it can be neither created nor destroyed. The energy of a system undergoing change (process) can be increased or decreased by exchange with the surroundings and can convert from one to another within that system. This is, therefore, simply a ‘bookkeeping’ law that declares the exchange and convertibility of energy and sees to it that all energy is accounted for when a change occurs. The first law does not indicate whether conversions of energy from one form to another are or are not performed perfectly or whether some forms may be completely converted to others. Such limitations are left to the second law.

10.1.1.2 Second law of thermodynamics

As pointed out in Section 10.1.1.1, energy is a conserved property, and no process is known to have taken place in violation of the first law of thermodynamics. Therefore, it is reasonable to conclude that a process must satisfy the first law to occur. However, as explained below, satisfying the first law alone does not ensure that a thermodynamic process will actually take place.

Processes proceed in a certain direction and not in the reverse direction. The first law places no restriction on the direction of a process, but satisfying the first law does not ensure that the process will actually occur. This inadequacy of the first law to identify whether a process can take place is remedied by introducing another general principle, the second law of Thermodynamics.

The use of the second law of thermodynamics is not limited to identifying the direction of processes, however. The second law also ensures that energy has not only quantity but also quality. The first law is concerned with the quantity of energy and the transformations of energy from one form to another with no regard to its quality. Preserving the quality of energy is a major concern to engineers, and the second law provides the necessary means to determine the quality as well as the degree of degradation of energy during a process.

The above statements serve as a starting point for the following formulation of the second law:

- energy consists of two components, one part is totally convertible into other forms of energy (called exergy), and one part is not at all convertible (called anergy)
- in any real thermodynamic process, part of the exergy is irreversibly converted into anergy.

10.1.1.3 Enthalpy and entropy

Enthalpy represents the amount of energy possessed by a thermodynamic system for transfer between itself and its environment. For example, in a chemical reaction, the change of enthalpy of the system is the heat of the reaction. In a phase change, such as from a liquid to a gas as boiling water in a steam generator, the enthalpy of the system is the heat of vaporisation. In a simple temperature change, the change of enthalpy with each degree is the capacity of the system at constant pressure. Mathematically, enthalpy H is identified as U + PV, where U is internal energy, P is pressure and V is volume.

Rudolph Clausius first introduced the term ‘entropy’ in 1865. He had noticed that a certain ratio of energy was constant in reversible, or ideal, heat cycles, where a cycle in general is a series of processes that begins and ends at the same state and thus can repeat indefinitely, or as long as needed. The ratio was heat exchanged to absolute temperature. Clausius decided that the conserved ratio must correspond to a real, physical quantity, and he named it ‘entropy’.

For a closed system, entropy can be defined as a quantitative measure of the amount of energy not available to do work. So it is a negative kind of quantity, the opposite of available energy, or in other words a measure of disorder or randomness.

10.1.1.4 The concept of reversibility

A reversible process is defined as a process that can be reversed without leaving any trace on the surroundings. That is, both the system and the surroundings are returned to their initial states at the end of the reverse process. This is possible only if the net heat exchange and net work exchange between the system and the surroundings are zero for the combined (original and reverse) processes. Processes that are not reversible are called ‘irreversible processes’.

It should be pointed out that a system can be restored to its initial state following a thermodynamic process, regardless of whether the process is reversible or irreversible. But for reversible processes, this restoration is made without leaving any net change on the surroundings, whereas for irreversible processes, the surroundings usually do some work on the system and, therefore, will not return to their original state.

Reversible processes do not actually occur in nature. They are merely idealisations of actual processes. Reversible processes can be viewed as theoretical limits for the corresponding irreversible ones. Some thermodynamic processes are more irreversible than others. It is not possible to have a reversible process, but it is possible to approach to it. The more closely a reversible process is approximated, the more work delivered by a work-producing device or the less work required by a work-consuming device.

The concept of reversible processes leads to the definition of second-law of thermodynamic, the efficiency of a thermodynamic related to the degree of approximation to the corresponding reversible processes. This enables us to comparison of the performance of different devices that are designed to do the same task on the basis of their efficiencies. The better the design, the lower the irreversibility and the higher the efficiency.

The factors that cause a process to be irreversible are called 'irreversibilities'. They include friction, unrestrained expansion, mixing of two gases, heat transfer across a finite temperature difference, electric resistance, inelastic deformation of solids, and chemical reactions. The presence of any of these effects renders a process irreversible. A reversible process involves none of these.

10.1.1.5 The ideal cycle (Carnot cycle)

One ideal cycle in which the heat is taken in at a constant upper temperature (T_a) and rejected at a constant lower temperature (T_b) is that suggested by Sadi Carnot. It consists of two reversible adiabatic (no heat is exchanged with the surrounding environment) (isentropic- no change in entropy) processes. When the working fluid is considered as water, or water vapour, the two isothermal (no change in temperature) processes are easily obtained by heating and cooling at constant pressure and temperature while the fluid is a wet vapour. The cycle is represented on the temperature-entropy (*T-s)* diagram for steam in Figure 10.1 and a diagrammatic sketch of the plant accompanies it.

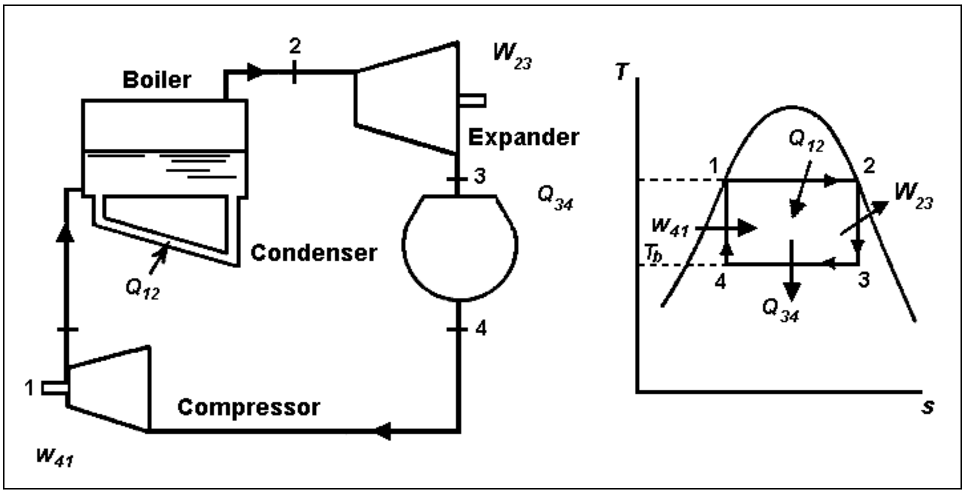


Figure 10.1: Ideal Carnot cycle

In the Carnot cycle, saturated water in state 1 (1) is evaporated in a boiler at constant pressure to form saturated steam in state 2 (2) with the addition of heat (*Q 12*). The steam is then expanded isentropically to state 3 (3) while doing work in a turbine or reciprocating engine (W_{23}). After expansion, the steam is then partially condensed at constant pressure while heat is rejected. Condensation is stopped at state 4 (4) where $s_4 = s_1$. Finally the steam is compressed isentropically in the rotary or reciprocating compressor to state 1 (1). The Carnot cycle is the most efficient cycle that can be executed between a thermal energy source at temperature T_a and temperature at sink T_b. Its thermal efficiency is expressed as:

$$\eta_{\text{th,Carnot}} = 1 - \frac{T_b}{T_a}$$

Reversible isothermal heat transfer is very difficult to achieve in reality because it would require very large heat-exchangers and it would take a very long time. Therefore, it is not practical to build an engine that would operate on a cycle that closely approximates the Carnot cycle.

The real value of the Carnot cycle comes from its being a standard against which the actual or other ideal cycles can be compared. The thermal efficiency of the Carnot cycle is a function of the temperatures sink and source, and the thermal efficiency relation for the Carnot cycle conveys an important message that is applicable to all cycles.

Thermal efficiency increases with an increase in the average temperature at which heat is added to the system or with a decrease in the average temperature at which heat is rejected from the system.

The overall thermal efficiency of a power plant is suitably measured by the proportion of latent energy in the fuel that is converted into useful mechanical work. The overall efficiency can be expressed as the product of two efficiencies:

a) the combustion efficiency, which expresses the proportion of latent energy in the fuel, transferred as heat to the working fluid
b) the cycle efficiency, which expresses the proportion of this, heat which is converted into mechanical work.

10.1.1.6 Properties of vapour (water vapour)

An important step in design of steam generating equipment and its operational cycle application, either for power or heat transfer or both, is to establish reliable information on steam properties. Steam tables currently in use are the ‘1967 ASME Steam Tables’ based on agreements reached at the ‘Sixth International Conference on the Properties of Steam’.

The steam tables include the corresponding pressure-temperature equilibrium values between the liquid and vapour phases referred to as ‘saturation’. Steam heated beyond saturation to higher temperatures is ‘superheated steam’. Water heated to temperatures below saturation (sub-cooled water) is referred to as ‘compressed water’ in the steam tables. Properties for the superheated steam and compressed water ranges are given in the steam tables, which also includes the intensive properties of specific volume, specific enthalpy, and specific entropy for specified temperatures, pressures and states (liquid or gas). Intensive properties are those which are independent of mass; they are also independent of the type of process or any past history. These are the state and thermodynamic properties required for numerical solutions to design and performance problems involving steam for heat transfer and power. The special significance of the important properties of enthalpy is a consequence of the laws of thermodynamics.

Fortunately, engineering problems deal mainly with changes or differences in enthalpy and entropy and it is not necessary to establish an absolute zero for these properties even though this may be achieved in the case of entropy. The steam tables set an arbitrary zero internal energy and entropy for the liquid state of water at the triple point corresponding to 273.16 K and a vapour pressure of 611.22 Pa. The enthalpy of water under these conditions is slightly positive.

Customarily, the boiler industry uses 300 K and 101353 Pa as the zero enthalpy of air and combustion products, although this practice is not widespread in other related engineering fields. A more general reference is one atmosphere pressure (101325 Pa) and 25 ºC (298.16 K). This is referred to as the standard reference point for listing the heats of formation of compounds from their elements in their standard states, latent heats of phase changes, free energy, and other important thermodynamic quantities.

10.1.2 The Rankine cycle as the standard cycle for steam power plants

There are two major reasons why the Carnot cycle is not used in practice. Firstly, because it has a low work ratio. Secondly, because of practical difficulties associated with compression. It would be difficult to control the condensation process so that it stopped at stage 4 (4) (Figure 10.1), and then carry out the compression of a very wet vapour efficiently. The liquid tends to separate out from the vapour and the compressor would have to deal with a non-homogeneous mixture. Moreover, the volume of the fluid is high and the compressor would be comparable in size and cost with the turbine. It is comparatively easy, on the other hand, to condense the vapour completely, and compress the liquid to boiler pressure in a small feed pump.

Another impracticality associated with the Carnot cycle can be eliminated by superheating the steam in the boiler, as shown schematically on a T-s diagram in Figure 10.2. The cycle that results is the Rankine cycle, which is the ideal cycle for vapour power plants. The ideal Rankine cycle does not involve any internal irreversibilities and consists of the following four processes:

stage 1 – stage 2 (1–2)	Isentropic compression in a pump
stage 2 – stage 3 (2–3)	Heat addition in a boiler at constant pressure
stage 3 – stage 4 (3–4)	Isentropic expansion in a turbine
stage 4 – stage 1 (4–1)	Heat rejection in a condenser at constant pressure

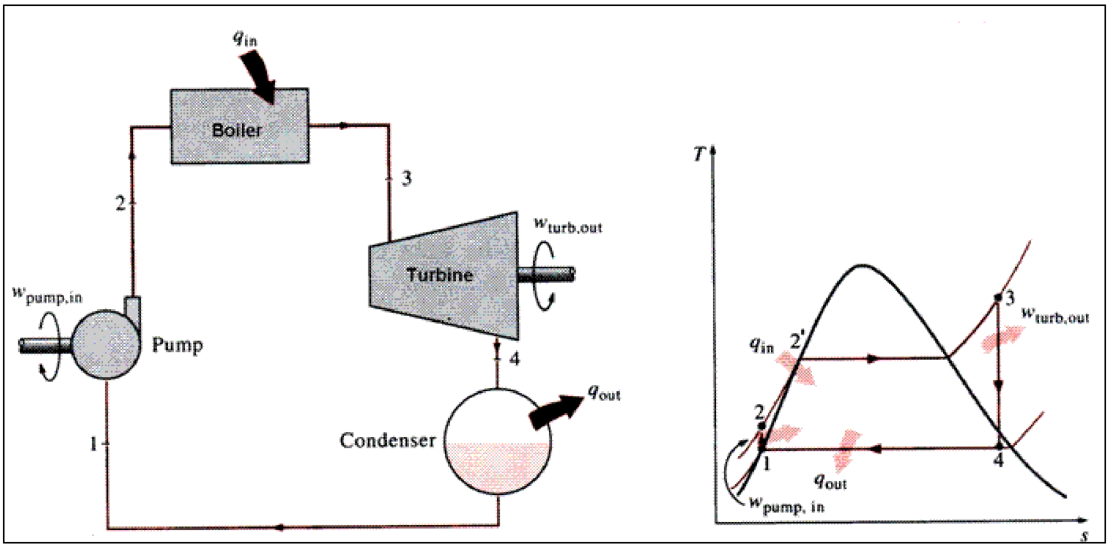


Figure 10.2: The simple ideal Rankine cycle

It is evident without calculation that the efficiency of this cycle will be less than that of the Carnot cycle operating between the same temperatures, because all the heat supplied is not transferred at the higher temperature. Some heat is added while the temperature of the working fluid varies from state 2 (2) to state 2’ (2’). From the comparison between the areas of the two cycles, that the net work output per kg of steam is greater in the Rankine cycle.

10.1.2.1 The externally irreversible Rankine cycle

The actual vapour power cycle differs from the ideal Rankine cycle, as illustrated in Figure 10.3, as a result of irreversibilities in various components. Fluid friction and undesired heat loss to the surroundings are the two most common sources of irreversibilities.

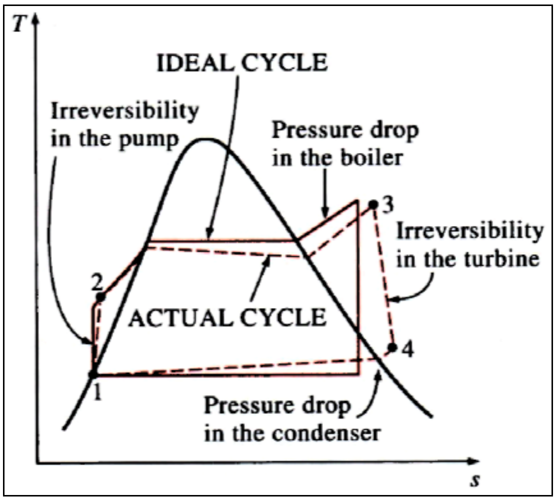


Figure 10.3: Deviation of an actual vapour power cycle from the ideal Rankine cycle

Fluid friction causes pressure drops in the boiler, the condenser, and the piping between various components. As a result, steam leaves the boiler at a somewhat lower pressure. Also, the pressure at the turbine inlet is somewhat lower than that at the boiler exit due to the pressure drop in the connecting pipes. The pressure drop in the condenser is usually very small. To compensate for these pressure drops, the water must be pumped to a sufficiently higher pressure than the ideal cycle needs. This requires a larger pump and larger work input to the pump.

The other major source of irreversibility is the heat loss from the steam to the surroundings as the steam flows through various components. To maintain the same level of net work output, more heat needs to be transferred to the steam in the boiler to compensate for these undesired heat losses. As a result, the efficiency of the cycle decreases.

Of particular importance are the irreversibilities occurring within the pump and the turbine. A pump requires a more work input, and a turbine produces less work output as a result of irreversibilities.

Other factors also need to be considered in the analysis of actual vapour power cycles. In actual condensers, for example, the liquid is usually sub-cooled to prevent the onset of cavitation, the rapid vaporisation and condensation of the fluid at the low pressure side of the pump impeller, which may eventually destroy it. Additional losses occur at the bearings between the moving parts as a result of friction. Steam that leaks out during the cycle and air that leaks into the condenser represent two other sources of loss. All these power consumed by the auxiliary have to be considered in evaluating the performance of actual power plants.

10.1.2.2 Efficiency improvement of the Rankine cycle

The basic idea behind all the modifications to increase the thermal efficiency of a power cycle is the same: increase the average temperature at which heat is transferred to the working fluid in the boiler, or decrease the average temperature at which heat is rejected form the working fluid in the condenser. That is, the average fluid temperature should be as high as possible during heat addition and as low as possible during heat rejection. Next three ways of accomplishing this for the simple ideal Rankine cycle are presented bellow:

A) Lowering the condenser pressure

Steam exists as a saturated mixture in the condenser at the saturation temperature corresponding to the pressure inside the condenser. Therefore, lowering the operating pressure of the condenser automatically lowers the temperature at which heat is rejected.

The effect of lowering the condenser pressure on the Rankine cycle efficiency is illustrated on a *T-s* diagram in Figure 10.4. For comparison purposes, the turbine inlet state is maintained. The shaded area on this diagram represents the increase in net work output as a result of lowering the condenser pressure from state 4 (4) to state 4'(4'). The heat input requirements also increase (represented by the area under curve state *2'*(2′) to stage *2* (2), but this increase is very small. Thus, the overall effect of lowering the condenser pressure is an increase in the thermal efficiency of the cycle.

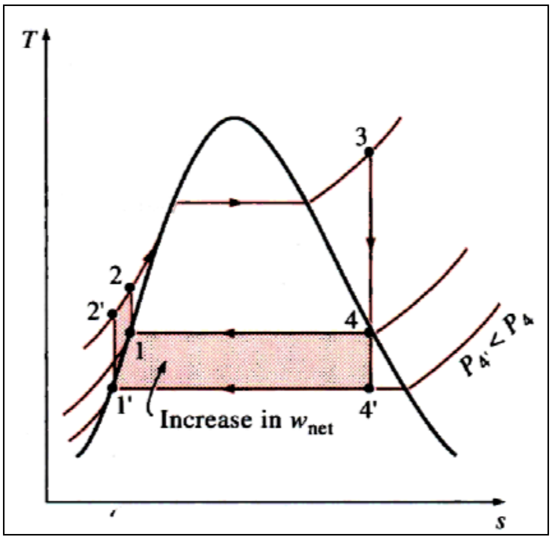


Figure 10.4: The effect of lowering the condenser pressure of the ideal Rankine cycle

B) Superheating the steam to high temperatures

The average temperature at which heat is added to the steam can be increased without increasing the boiler pressure by superheating the steam to high temperatures. The effect of superheating on the performance of vapour power cycles is illustrated on a *T-s* diagram in Figure 10.5. The shaded area on this diagram represents the increase in the net work. The total area under the process curve stage 3 (3) – stage *3'*(3′) represents the increase in the heat input. Thus, both the net work and heat input increase as a result of superheating the steam to a higher temperature. The overall effect is an increase in thermal efficiency, however, since the average temperature at which heat is added increases.

Superheating the steam to higher temperatures has another very desirable effect: it decreases the moisture content of the steam at the turbine exit, as can be seen from the *T-s* diagram (the quality at state 4' (4') is higher than that at state 4 (4)).

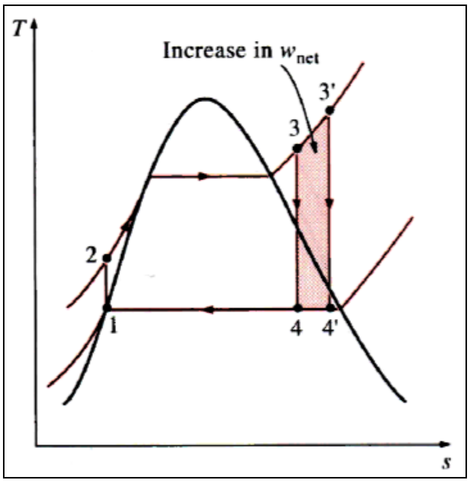


Figure 10.5: The effect of superheating the steam to higher temperatures in the ideal Rankine cycle

C) Increasing the boiler pressure. Supercritical cycles.

Another way of increasing the average temperature during the heat addition process is to increase the operating pressure of the boiler (also called supercritical cycles), which automatically raises the temperature at which boiling take place. This, in turn, raises the average temperature at which heat is added to the steam and thus raises the thermal efficiency of the cycle.

The effect of increasing the boiler pressure on the performance of vapour power cycles is illustrated on a *T*-*s* diagram in Figure 10.6. Notice that for a fixed turbine inlet temperature, the cycle shifts to the left and the moisture content of steam at the turbine exit increases. This undesirable side effect can be corrected, however, by reheating the steam, as discussed in Section 10.1.2.3.

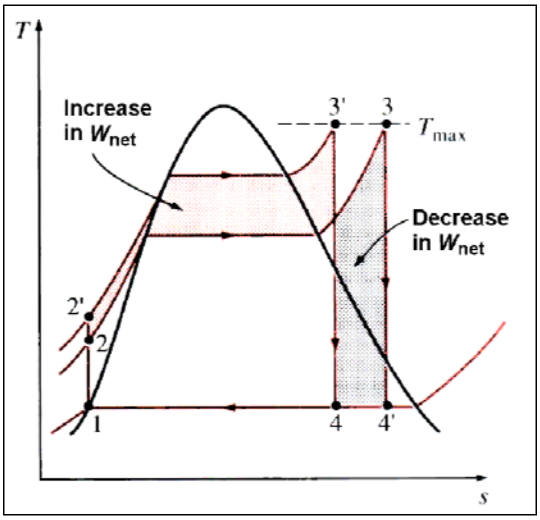


Figure 10.6: The effect of increasing the boiler pressure in the ideal Rankine cycle

Operating pressures of boilers have gradually increased over the years from about 2.7 Mppa in 1992 to over 30 Mpa today, generating enough steam to produce a net power output of 1000 MW or more. Today, many modern steam power plants operate at supercritical pressures (*P* >22.09 Mppa) (see Figure 10.7).

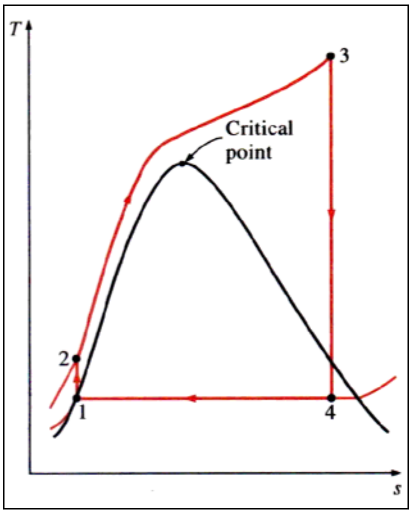


Figure 10.7: A supercritical Rankine cycle

10.1.2.3 Reheat

The ideal reheat Rankine cycle (Figure 10.8) differs from the simple ideal Rankine cycle in that the expansion process takes place in two stages. In the first stage (the high pressure turbine), steam is expanded isentropically to an intermediate pressure and sent back to the boiler where it is reheated at constant pressure, usually to the inlet temperature of the first turbine stage. Steam then expands isentropically in the second stage (low pressure turbine) to the condenser pressure.

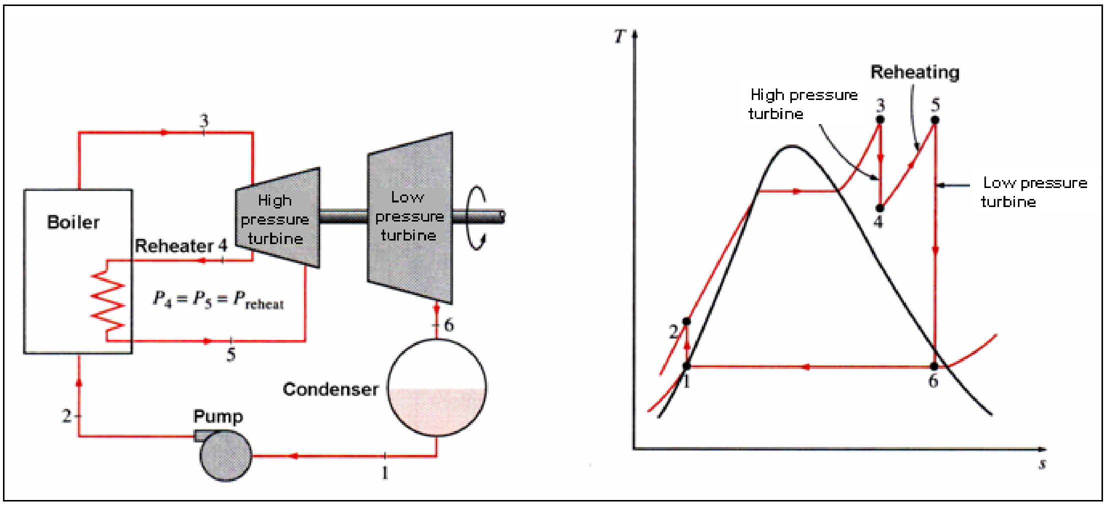


Figure 10.8: The ideal reheat Rankine cycle

The incorporation of the single reheat in a modern power plant improves the cycle efficiency by 4 to 5 per cent by increasing the average temperature at which heat is added to the steam.

The average temperature during the reheat process can be increased by increasing the number of expansion and reheat stages. As the number of stages is increased, the expansion and reheat processes approach an isothermal process at the maximum temperature. The use of more than two reheat stages, however, is not practical.

10.1.2.4 Regeneration

A practical regeneration process in steam power plants is accomplished by extracting, or ‘bleeding’, steam form the turbine at various points. This steam, which could have produced more work by expanding further in the turbine, is used to heat the feed-water instead. The device where the feed-water is heated by regeneration is called a ‘regenerator’, or a ‘feed-water heater’.

Regeneration not only improves cycle efficiency, but also provides a convenient means of de-aerating the feed-water (removing the air that leaks in at the condenser) to prevent corrosion in the boiler. It also helps control the large volume flowrate of the steam at the final stages of the turbine (due to the large specific volumes at low pressures). Therefore, regeneration is used in all modern steam power plants since its introduction in the early 1920s.

A feed-water heater is basically a heat-exchanger where heat is transferred from the steam to the feed-water either by mixing the two fluid streams (open feed-water heaters) or without mixing them (closed feed-water heaters).

The schematic of a steam power plant with one closed feed-water heater and the *T-s* diagram of the cycle are shown in Figure 10.9. In an ideal closed feed-water heater, the feed-water is heated to the exit temperature of the extracted steam, which ideally leaves the heater as a saturated liquid at the extraction pressure. In actual power plants, the feed-water leaves the heater below the exit temperature of the extracted steam because a temperature difference of at least a few degrees is required for any effective heat transfer to take place.

The condensed steam is then either pumped to the feed-water line or routed to another heater or to the condenser through a device called a ‘trap’. A trap allows the liquid to be throttled to a lower pressure region but traps the vapour. The enthalpy of steam remains constant during this throttling process.

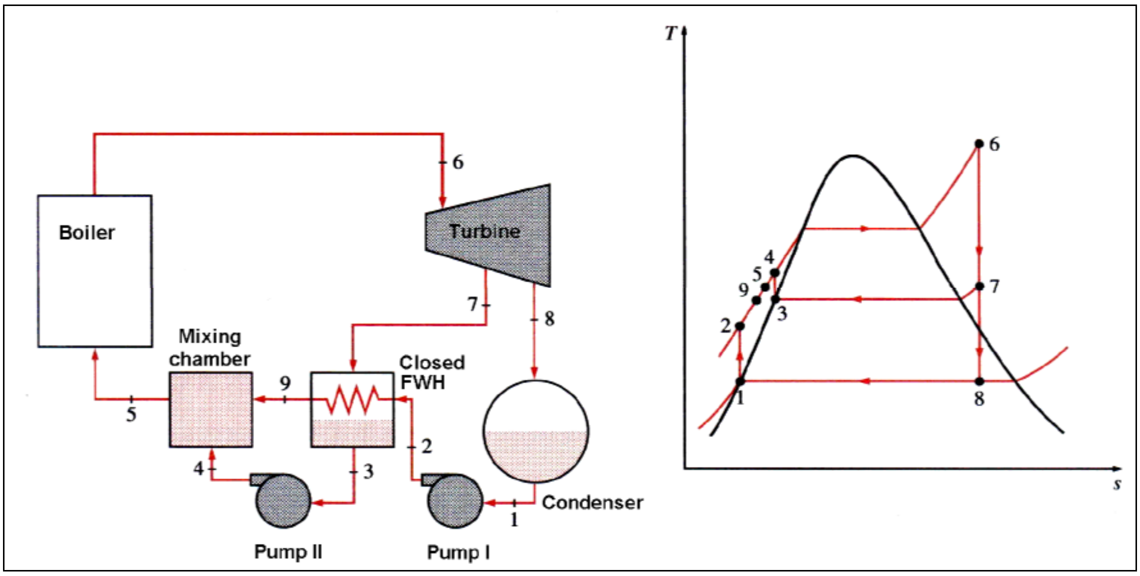


Figure 10.9: The ideal regenerative Rankine cycle with a closed feed-water heater

10.1.3 The Joule or Brayton cycle as the standard cycle for gas turbines

10.1.3.1 The ideal Brayton cycle

George Brayton first proposed the Brayton cycle for use in the reciprocating oil burning engine that he developed around 1870. Today, it is used for gas turbines only where both the compression and expansion processes take place in rotating machinery. Gas turbines usually operate on an open cycle. Fresh air at ambient conditions is drawn into the compressor where its temperature and pressure are raised. The high pressure air proceeds into the combustion chamber where the fuel is burned at constant pressure. The resulting high temperature gases then enter the turbine where they expand to the atmospheric pressure, thus producing power. The exhaust gases leaving the turbine are thrown out (not recirculated), causing the cycle to be classified as an open cycle.

The open gas turbine cycle described above can be modelled as a closed cycle, as shown in Figure 10.10, by utilising the air-standard assumptions where deductions about the performance uses air as the working fluid. Here, the compression and expansion processes remain the same, but the combustion process is replaced by a constant pressure heat addition process from an external source, and the exhaust process is replaced by a constant pressure heat rejection process to ambient air. The ideal cycle that the working fluid undergoes in this closed loop is the Joule or Brayton cycle, which is made up of four internally reversible processes:

stage 1 – stage 2 (1–2)	Isentropic compression in a pump
stage 2 – stage 3 (2–3)	Heat addition in a boiler at constant pressure
stage 3 – stage 4 (3–4)	Isentropic expansion in a turbine
stage 4 – stage 1 (4–1)	Heat rejection in a condenser at constant pressure

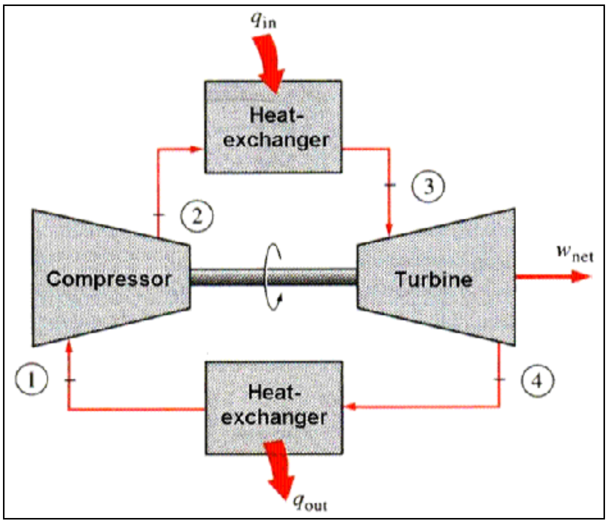


Figure 10.10: A closed cycle gas turbine engine

The *T-s* and *P-v* diagrams of an ideal Brayton cycle are shown in Figure 10.11. Notice that all four processes of the Brayton cycle are executed in steady flow devices; thus they should be analysed as steady flow processes.

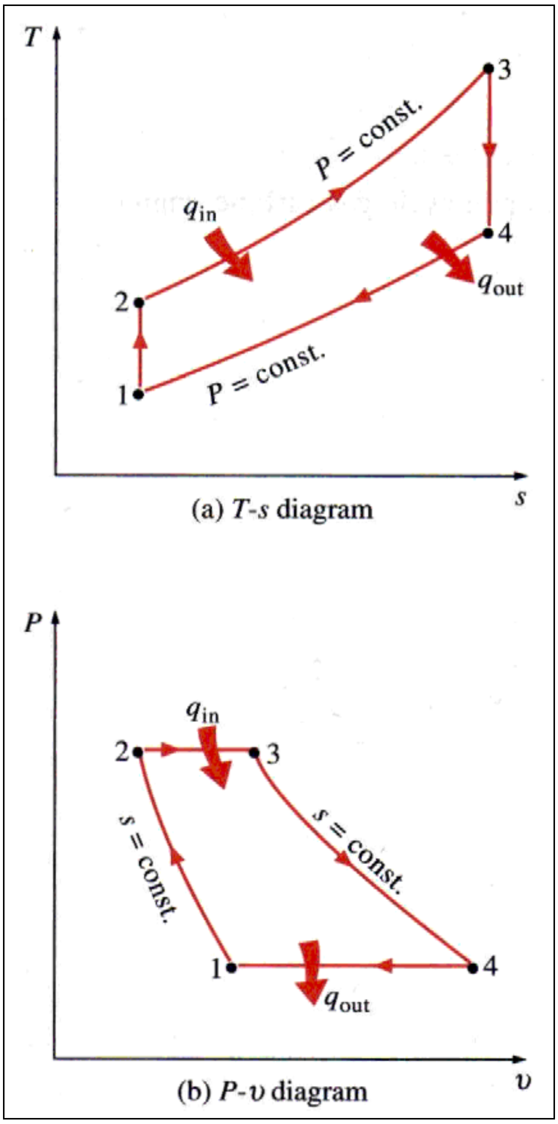


Figure 10.11: *T-s* and *P-v* diagrams for the ideal Brayton cycle

The thermal efficiency of a gas turbine engine depends on the allowable maximum gas temperature at the turbine inlet. Raising the turbine inlet temperature from 900 to 1200 ºC increases the power output by 71 % and the thermal efficiency by 26 %. Significant advances, such as coating the turbine blades with ceramic layers and cooling the blades with the discharge air from the compressor have been made during the last two decades. As a result, today's gas turbines can withstand temperatures as high as 1425 ºC at the turbine inlet, and gas turbine power plants have efficiencies well over 30 %.

Gas-turbine power plants are mostly utilised in the power generation industry to cover emergencies and peak periods because of their relatively low cost and quick response time. Gas turbines are also used in conjunction with steam power plants, the exhaust gases of the gas turbine serve as the heat source for the steam (see Combined Cycles).

10.1.3.2 Non-ideal Brayton cycle

The real gas turbine cycle differs from the ideal Brayton cycle for several reasons. For one thing, some pressure drop during the heat addition and rejection processes is inevitable. More importantly, the actual work input to the compressor will be more, and the actual work output of the turbine will be less because of irreversibilities such as friction and non-quasi-equilibrium operation conditions of these devices.

As soon as compressor and turbine inefficiencies are introduced, as indicated in Figure 10.12, where states *2a (2a)* and stage *4a* (*4a)* are the real exit states of the compressor and the turbine, respectively, and *2s* and *4s* are the corresponding states for the isentropic case, the importance of a high work ratio becomes obvious. With a low value of T_3, the difference between the turbine work and compressor work becomes very small, and a slight decrease in the turbine work and increase in the compressor work is sufficient to reduce the work output, and cycle efficiency, to zero.

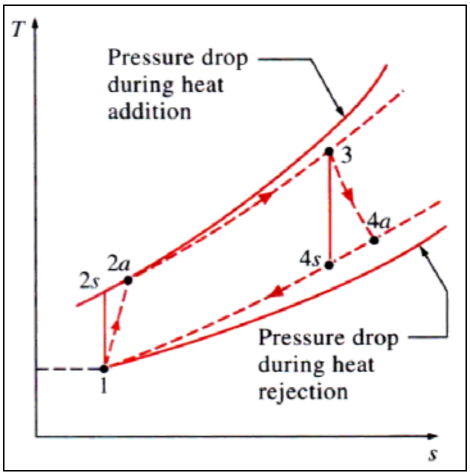


Figure 10.12: The deviation of an actual gas turbine cycle from the ideal Brayton cycle as a result of irreversibilities

The efficiency of the irreversible cycle can be shown to be not only a function of pressure ratio (r_p), but also of T_3 Figure 10.13). There is an optimum pressure ratio for a maximum cycle efficiency as well as an optimum pressure ratio for maximum specific work output (although these optimum pressure ratios are not the same). The ideal efficiency curve is also shown in Figure 10.13, to emphasise the marked reduction in efficiency caused by irreversibilities in the compressor and turbine. The following sections deal with the more important modifications to the simple cycle which may be adapted to improved both the ideal efficiency and work ratio.

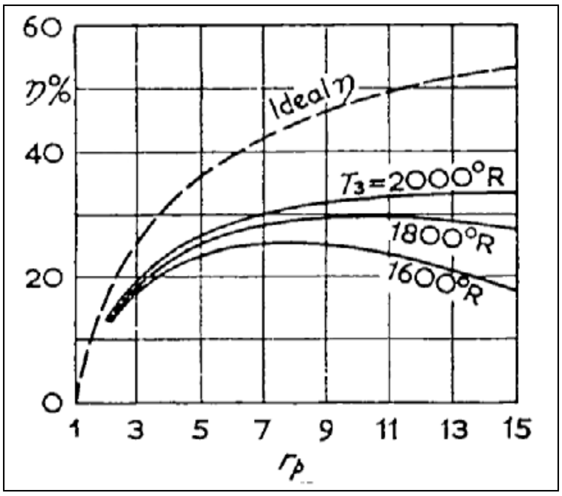


Figure 10.13: Thermal efficiency of the Brayton cycle as a function of pressure ratio (r_P) and temperature (T_3)

10.1.3.3 Regeneration

In the recuperative (or regenerative) cycle, a counter-flow heat-exchanger transfers exhaust heat to the compressed air before it enters the combustor. This is shown schematically in Figure 10.14. The amount of fuel needed to heat the air to combustion temperature is reduced by up to 25 %.

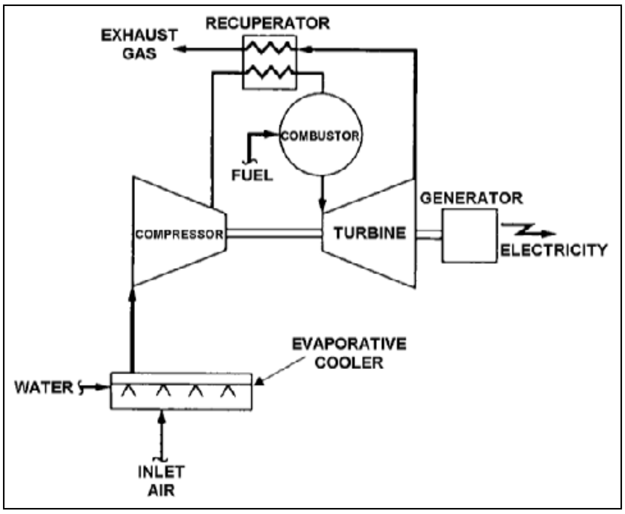


Figure 10.14: Evaporative cooling and recuperative cycles

10.1.3.4 Compressor intercooling

In the intercooled cycle, a heat-exchanger is placed in the air path between low and high pressure sections of the compressor, as shown in Figure 10.15. Compression of cool air requires less work than compression of warm air. This heat-exchanger is designed to cool the air and reduce the amount of work required in the high pressure section of the compressor, increasing both power output and efficiency. The intercooler can be a direct contact (evaporative) or an extended surface type heat-exchanger.

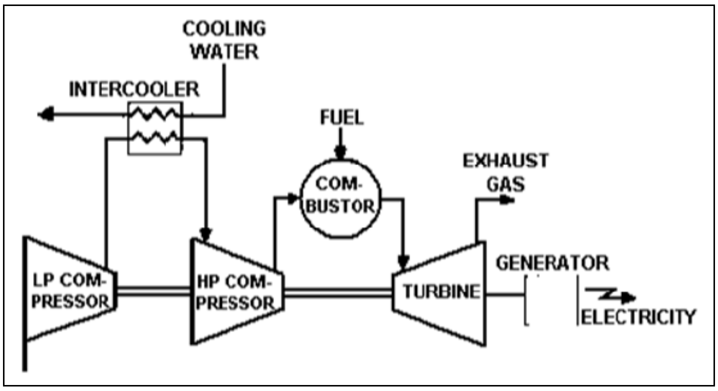


Figure 10.15: Intercooled cycle

10.1.3.5 Turbine reheat

The gas turbine reheat cycle is analogous to the steam turbine reheat cycle. The hot gases are partially expanded through the turbine, reheated by a second stage combustor, and returned to the turbine. This cycle is more complex than the standard gas turbine cycle. Figure 10.16 illustrates a schematic representation of this cycle and the characteristics are as follows:

- the reheat cycle is more efficient
- to protect the reheat combustor, the high pressure turbine is required to lower the temperature of the hot gases entering the reheat combustor
- in general, it is necessary to increase the fuel/air ratio to increase specific power. Metallurgy and cooling technology limit the turbine inlet temperature. The two-stage combustor allows more fuel to be injected without exceeding this temperature limit. This increases the exhaust temperature and makes the reheat combustion turbine more suitable for the combined cycle
- the reheat combustion turbines higher specific power results in less residual oxygen in the exhaust sections which are smaller than those for a simple cycle gas turbine of the same output.

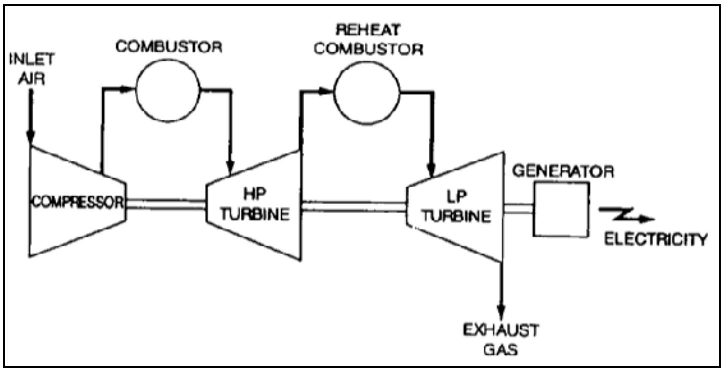


Figure 10.16: Reheat cycle

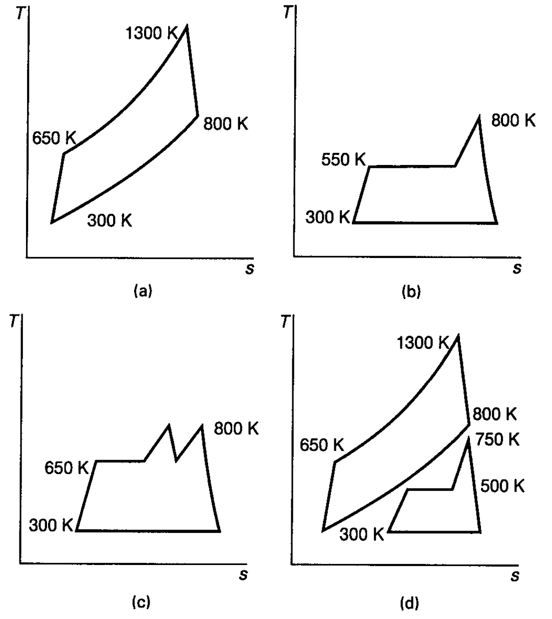
10.1.4 Combined cycles

As described in Section 10.1.1.5, the Carnot cycle is the most efficient cycle that can be executed.

Naturally, the efficiencies of real processes are lower since there are losses involved. The process efficiency can be improved by raising the maximum temperature in the cycle, releasing the waste heat at a lower temperature, or by improving the process to minimise the internal exegetic losses.

The interest in combined cycles arises particularly from these considerations. By its nature, no single cycle can make all of these improvements to an equal extent. It thus seems reasonable to combine two cycles, one with high process temperatures and the other with a good 'cold end'.

In a simple cycle gas turbine, attainable process temperatures are high as energy is supplied directly to the cycle without heat exchange. The exhaust heat temperature, however, is also high. In the steam cycle, the maximum process temperature is much lower than the gas turbine process, but the exhaust heat is returned to the environment at a low temperature. As illustrated in Table 10.1combining a gas turbine and a steam turbine thus offers the best possible basis for a high efficiency thermal process.



Plant	(a)	(b)	(c)	(d)
Average temperature of heat supplied, K	1000	600	680	1000
Average temperature of heat rejected, K	520	300	300	300
Carnot efficiency, %	48	50	50	70

Parameters	**Gas turbine power plant (cycle a)**	**Steam turbine power plant (cycle b)**	**Steam turbine power plant with reheating (cycle c)**	**Combined–cycle power plant (cycle d)**
Average temperature of heat supplied, K	1000	600	680	1000
Average temperature of dissipated heat, K	520	300	300	300
Carnot efficiency, %	48	50	50	70

Table 10.1: Thermodynamic comparison of gas turbine, steam turbine and combined cycle processes
[50, Korobitsyn, 1998]

The last line in Table 10.1 shows the Carnot efficiencies of the various processes. Although that is not the case in reality, this table can be used as an indicator of the quality of a thermal process. The value shown makes clear just how interesting the combined cycle power plant is when compared to processes with only one cycle. Even a sophisticated, supercritical conventional reheat steam turbine power plant has a Carnot efficiency of around 20 points lower than that of a good combined cycle plant. For combined cycle power plants, actual efficiencies are around 75 % of the Carnot efficiency. The differences between the actual efficiencies attained by a combined cycle power plant and the other processes are, therefore, not quite as large as illustrated in Table 10.1. The relatively larger drop in the combined cycle efficiency is caused by higher internal energy losses due to the temperature differential for exchanging heat between the gas turbine exhaust and the water/steam cycle.

Recent developments in gas turbine technology have made the combined gas-steam cycle economically very attractive. The combined cycle increases the efficiency without appreciably increasing the initial cost. Consequently, many new power plants operate on combined cycles, and many more existing steam or gas turbine plants are being converted to combined cycle power plants. Thermal efficiencies well over 40 % are reported as a result of conversion.

10.1.5 Co-generation (CHP)

In all the cycles discussed so far, the sole purpose was to convert a portion of the heat transferred to the working fluid to work, which is the most valuable form of energy. The remaining portion of the heat is rejected to rivers, lakes, oceans, or to the air as waste heat, because its quality (or grade) is too low to be of any practical use.

Many systems or devices, however, require energy input in the form of heat, called ‘process heat’, usually supplied by steam at 5 to 7 atm and 150 to 200 ºC. Energy is usually transferred to the steam by burning coal, oil, natural gas, or another fuel in a furnace.

The temperature in furnaces is typically very high (around 1370 ºC), and thus the energy in the furnace is of very high quality. This high quality energy is transferred to water to produce steam at about 200 ºC or below (a highly irreversible process). Associated with this irreversibility is, of course, a loss in work potential and thus a loss of exergy that is the scarce resource and must, therefore, be used sparingly. So it is simply not wise to use high quality energy to accomplish a task that could be accomplished with low quality energy.

A plant which produces electricity while meeting the process heat requirements of certain industrial processes, is called a ‘co-generation plant’. In general, co-generation is the production of more than one useful form of energy (such as process heat and electric power) from the same energy source.

Either a steam turbine (Rankine) cycle or a gas turbine (Brayton) cycle or even a combined cycle can be used as the power cycle in a co-generation plant. The schematic of an ideal steam turbine co-generation plant is shown in Figure 10.17.

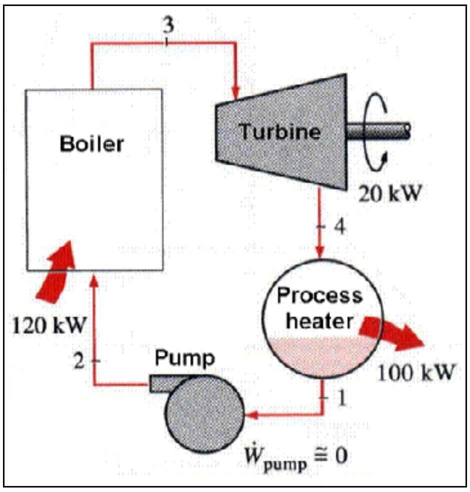


Figure 10.17: An ideal co-generation plant

In the absence of a condenser, no heat is rejected from this plant as waste heat. In other words, all the energy transferred to the steam in the boiler is utilised as either process heat or electric power.

To take account of the latter benefit, the total efficiency, perhaps better called the energy utilisation factor (EUF), is a more adequate measure of performance than the simple work.

The ideal steam turbine co-generation plant described above is not practical because it cannot adjust to the variations in power and process heat loads. The schematic of a more practical (but more complex) co-generation plant is shown in Figure 10.18. Under normal operation, some steam is extracted from the turbine at some predetermined intermediate pressure state '6' P_6. The rest of the steam expands to the condenser pressure state '7' P_7 and is then cooled at constant pressure. The heat rejected from the condenser represents the waste heat for the cycle.

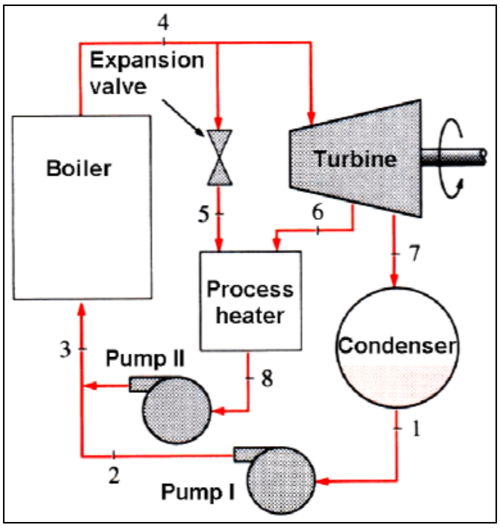


Figure 10.18: A co-generation plant with adjustable loads

At times of high demand for process heat, all the steam is routed to the process heating units and none to the condenser. The waste heat is zero in this mode. If this is not sufficient, some steam leaving the boiler is throttled by an expansion or pressure reducing valve (PRV) to the extraction pressure P_6 and is directed to the process heating unit. Maximum process heating is realised when all the steam leaving the boiler passes through the PRV. No power is produced in this mode. When there is no demand for process heat, all the steam passes through the turbine and the condenser, and the co-generation plant operates as an ordinary steam power plant.

Under optimum conditions, a co-generation plant simulates the ideal co-generation plant discussed earlier. That is, all the steam expands in the turbine to the extraction pressure and continues to the process heating unit. This condition may be difficult to achieve in practice because of the constant variations in the process heat and power loads. But the plant should be designed so that the optimum operating conditions are approximated most of the time.

10.2 Annex 2. Technical options to remove CO_2 from flue-gases

Given current technology, increasing the thermal efficiency of processes and techniques - generating energy is the most important measure in reducing the amount of greenhouse gases emitted per unit of energy produced. Efficiency increases are limited by various factors so that, even with increased efficiency, significant amounts of CO_2 will be emitted. To reduce the emissions of CO_2 further, different technical options are currently under development or are at a research stage and might be available in the future. These technical options are well described by the IEA (International Energy Agency), [41, IEA, 1992] and will be briefly presented in this annex of the document.

10.2.1 Absorption techniques to remove CO_2 from flue-gases

Absorption of CO_2 is a technique used in the chemical industry for the commercial production of CO_2. The amounts of CO_2 currently produced are small in comparison with the total amount of CO_2 that could be removed from the flue-gas in the global sector-generating energy. Therefore such absorption techniques would have to be introduced on a much larger scale. Typically three basic types of absorption systems are possible: chemical, physical and hybrid systems.

In chemical absorption systems, the CO_2 reacts with chemical solvents to form a weakly bonded intermediate compound which is broken down by the application of heat, regenerating the original solvent and producing a CO_2 stream. Typical solvents are amine- or carbonate-based, such as MEA, diethanolamine (DEA), ammonia and hot potassium carbonate. These processes can be used at low CO_2 partial pressures, but the flue-gas must be free of SO_2, O_2 hydrocarbons and particulates because of operating problems in the absorber.

The CO_2 can also be physically absorbed in a solvent and then regenerated using heat and/or pressure reduction. Typical solvents are dimethylether of polyethylene glycol and cold methanol, which are applied at high pressure. At low pressures, the chemical absorption processes are economic.

Hybrid solvents combine the best characteristics of both the chemical and physical solvents and are usually composed of a number of complementary solvents.

All the absorption processes operate in essentially the same manner by scrubbing the flue-gas in absorption towers to collect the CO_2 and then regenerating the solvent and releasing the CO_2.

10.2.2 Adsorption techniques to remove CO_2 from flue-gases

Solid adsorption methods employ a physical attraction between the gas and ‘active sites’ on the solid, whereas solid absorption methods employ a chemical reaction to capture the target gas. There are several adsorption methods used commercially in the process industries that may be applicable for removing CO_2 from power plant flue-gases. These employ adsorbent beds of alumina and zeolite molecular sieves (natural or manufactured aluminosilicate).

There are various methods of regeneration. Pressure swing regeneration or adsorption (PSA) involves lowering the pressure in the vessel containing the saturated bed until trapped gases are pulled off the bed. The regeneration cycles are relatively short and are typically measured in seconds. Thermal (or temperature) Swing Adsorption employs high temperature regeneration gas to drive off the trapped gas. The regeneration cycles are quite long (measured in hours) and result in larger quantities of adsorbent being required than with PSA systems.

10.2.3 Cryogenic techniques to remove CO_2 from flue-gases

Cryogenic separation involves cooling the gases to very low temperatures so that frozen CO_2 can be separated. The potential advantages of the process include the possibility of direct disposal of CO_2 ice (e.g. in the deep ocean) and the high purity of the separated gas which is close to 100 %. The disadvantage includes the high energy input required for reaching the cryogenic temperature. The major energy requirements are incurred during the compression stage so that improvements in this area would greatly reduce the overall power plant efficiency loss [40, Soria, et al., 1998].

10.2.4 Membrane techniques to remove CO_2 from flue-gases

In membrane separation, an appropriate membrane is used to separate the flue-gases into a CO_2 rich and lean gas stream. Two membrane operations are possible, gas separation and gas absorption. The combination of MEA and membranes is said to be the best option.

Gas separation membranes rely on a difference in physical or chemical interaction between components present in a gas mixture with the membrane material causing one component to permeate faster through the membrane than others.

Gas absorption membranes are membranes which are used as contacting devices between a gas flow and a liquid flow. The separation is caused by the presence of an absorption liquid on one side of the membrane. In contrast with gas separation membranes, it is not essential that the membrane has any selectivity at all.

10.2.5 The Carnol technique to remove CO_2 from flue-gases

The Carnol system, which is under development in the US, combines CO_2 removal from coal-fired power plants with methanol generation. It thus eliminates the need for CO_2 disposal. Part of the CO_2 emitted is used for methanol production, and some of the carbon is separated in solid form during the process. As such, it can either be stored or sold. The proposed system also uses the waste heat from the methanol production to decrease the energy needs for CO_2 extraction from the stack gases [40, Soria, et al., 1998].This process is just in the research stage.

10.2.6 Comparison of the different CO_2 removal options

A comparison of the different technical options that might in the future be available for CO_2 removal from large combustion plants has been carried out by the IEA Greenhouse Gas R&D Programme [41, IEA, 1992]. The four following power generation schemes have been studied:

1) a modern pulverised coal-fired power plant equipped with flue-gas desulphurisation (FGD) and operating with a subcritical high temperature steam cycle, assuming an efficiency of 40 %
2) a natural gas fired combined cycle power plant assuming an overall electrical efficiency of 52 %
3) an integrated gasification combined cycle (IGCC) power plant in which a coal slurry is fed to an oxygen blown gasifier of the entrained flow type assuming an efficiency of 42 %
4) a power plant burning pulverised coal in oxygen using recycled CO_2 to moderate the combustion temperature, assuming an efficiency of 33 %. It should be noted that this technique must be regarded as a long-term one.

As a base case for each of the techniques mentioned above, a 500 MW_e power plant, with a 35 year working life has been assumed. Furthermore, the plants are assumed to be seawater cooled and located on the coast in Western Europe. The ambient conditions are 15 ºC, 1.013 bar, relative humidity 60 % and the cooling water is available at 15 ºC. The design fuel is an internationally traded Australian bituminous coal of 0.86 % sulphur content from the Drayton mine. Plant emissions are controlled according to EU Directives. Also 90 % removal of sulphur dioxide (SO_2) has been specified.

For the gas turbine combined cycle case study, two gas turbines are used to obtain a net power output of approximately 500 MW with fuel being a typical Brent field natural gas.

The results of this study are presented in the Table 10.2 andTable 10.3. The information on costs was originally given in US dollars, nominally set in the third quarter of 1992. For the purpose of this document, the cost has been converted to euros using the exchange rate from October 2000. The accuracy is believed to be around +/- 30 %, so results should be taken only as an indication. It should also be noted that these figures do not take into account the cost of carbon dioxide disposal, which will be a necessary measure for most of the techniques discussed.

The disposal of carbon dioxide is an integral part of a complete strategy to avoid major greenhouse gas emissions from plants-generating energy in the future, but it is not an immediate operational issue for a large combustion plant and is, therefore, not described in this document. However, possible options for large-scale disposal of CO_2 are:

- disposal in the deep ocean
- disposal in deep aquifers
- use for enhanced oil recovery (EOR)
- disposal in exhausted gas and oil reservoirs.

Performance parameter	CO_2 removal technique	Pulverised coal power plant with FGD	Gas turbine combined cycle	Integrated gasification combined cycle	Pulverised coal combustion in oxygen using recycled CO_2	Notes
Changes in the net efficiency by applying different CO_2 removal techniques according to a given reference case	Reference efficiency without CO_2 removal	40 %	52 %	42 %	33 %	
	Absorption	29 %	42 %	28 %	30 %	Integrated gasification combined cycle using solvents may lead to 36 % efficiency instead of 42 % as a reference
	Adsorption PSA	28 %	33 %	26 %	29 %	
	Adsorption TSA	29 %	39 %	29 %	-	
	Cryogenic technique	–	–	36 %	27 %	Cryogenic measures have only be considered the IGCC and the pulverised coal combustion in oxygen using recycled CO_2
	Separation membrane	31 %	31 %	26 %	31 %	The decrease in efficiency is much higher due to high compression requirements
	Absorption membrane + MEA	30 %	47 %	32 %	30 %	
CO_2 captured	Absorption	90 %	85 %	90 %	99 %	
	Adsorption PSA, TSA	95 %	95 %	95 %	95 %	
	Cryogenic technique			85 %	85 %	
	Separation membrane	80 %	80 %	80 %	80 %	
	Absorption membrane + MEA	80 %	80 %	80 %	80 %	
CO_2 in product	Absorption	99.2 %	99.4 %	99.8 %	96 %	
	Adsorption PSA, TSA	75 %	50 %	60 %	97 %	
	Cryogenic technique			97 %	99 %	
	Separation membrane	55 %	16 %	30 %	97 %	
	Absorption membrane + MEA	55 %	16 %	30 %	97 %	
Note: Based on an IEA study to demonstrate the possible removal options which might be considered in the future						

Table 10.2: Comparison of different combustion techniques with and without CO_2 removal [41, IEA, 1992]

Performance parameter	CO_2 removal technique	Pulverised coal power plant with FGD	Gas turbine combined cycle	Integrated gasification combined cycle	Pulverised coal combustion in oxygen using recycled CO_2	Notes
Cost per tonne of CO_2 avoided (EUR/tonne)	Absorption	40	63	99	18	
	Adsorption PSA	96	623	235	24	
	Adsorption TSA	302	459	413	-	
	Cryogenic technique			26	29	Cryogenic measures have only be considered the IGCC and the pulverised coal combustion in oxygen using recycled CO_2
	Separation membrane	53	384	143	10	
	Absorption membrane + MEA	51	35	48	18	
Specific investment cost (EUR/kW)	Reference case without CO_2 removal	1213	805	1790	2344	
	Absorption	2112	1567	3731	3557	
	Adsorption PSA	1569	1376	2465	2510	
	Adsorption TSA	2363	1779	3475	-	
	Cryogenic technique	-	-	2763	4125	
	Separation membrane	2411	3573	5567	2537	
	Absorption membrane + MEA	1885	-	3137	-	
Note: Based on an IEA study to demonstrate costs of the possible removal options which might be considered in the future						

Table 10.3: Comparison of different combustion techniques with and without CO_2 removal
[41, IEA, 1992]