Exemplary investigation into the state of practical realisation of integrated environmental protection with regard to large combustion plants in Germany

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16. Abstract

The EC Directive on Integrated Pollution Prevention and Control (IPPC-Directive) addresses all aspects of environmental protection including emissions into the atmosphere, liquid discharges, waste related issues, efficient use of energy and resources and safety aspects. It aims at achieving a high level protection for the environment as a whole. In order to support the exchange of information on best available techniques (BAT) in the frame of this Directive the German Environmental Protection Agency (Umweltbundesamt) initiated a comprehensive survey of operational experience from large combustion plants in Germany. Based on this survey this report presents techniques used in these installations to combust solid, liquid and gaseous fuels including the operational experience of in total 31 installations. This selection includes both new and retrofitted power plants. The presentation of individual installations includes 18 examples of coal-fired plants, 2 biomass-fired plants, 4 installations for liquid and 8 examples for gaseous fuels. In addition to this, examples for the co-combustion of waste or secondary fuels are given. All examples as well as the presentation of criteria for the selection of BAT were communicated to the European IPPC Bureau in Seville. Many of these examples have already been integrated into the current draft of the BAT Reference Document.

17. Keywords

Best Available Technique, BAT, IPPC Directive, Large Combustion Plants, LCP, Gas turbines, Avoidance, Abatement, Emission, Wastewater, Waste, Noise

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14. Abbildungen
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16. Kurzfassung

In der EG-Richtlinie über die integrierte Vermeidung und Verminderung der Umweltverschmutzung vom 30. Oktober 1996 (IVU-Richtlinie) werden sowohl Emissionen in Luft, Wasser und Boden als auch abfallwirtschaftliche Aspekte, Ressourcen- und Energieeffizienz sowie die Vorbeugung von Unfällen erfasst. Ziel ist es, ein hohes Schutzniveau für die Umwelt insgesamt zu erreichen. Zur Unterstützung der Informationsaustauschs über beste verfügbare Techniken (BVT) im Rahmen der Richtlinie führte das Umweltbundesamt eine umfassende Erhebung zu den Betriebserfahrungen von Großfeuerungsanlagen in der Bundesrepublik Deutschland durch. Aufbauend auf diese Erhebung sind im vorliegenden Bericht die bei Großfeuerungen für feste, flüssige und gasförmige Brennstoffe eingesetzten Techniken erläutert und die Betriebserfahrungen dokumentiert. Dabei wurden Angaben von insgesamt 31 Standorten einbezogen. Die Auswahl enthält sowohl neu errichtete, als auch nachgerüstete Anlagen. Es wurden insgesamt achtzehn Kohlekraftwerke, zwei Biomassefeuerungen, vier Feuerungen für flüssige Brennstoffe und acht Beispielanlagen für gasförmige Brennstoffe als Einzeldarstellungen in den Bericht aufgenommen. Hinzu kommen Beispiele für die Mitverbrennung von Abfällen und Ersatzbrennstoffen. Alle Anlagenbeispiele sowie die Ausführungen zu den Kriterien für die Bestimmung von BVT wurden dem Europäischen IPPC Bureau in Sevilla übermittelt. Viele dieser Beispiele wurden in den aktuellen Entwurf zum BVT-Merkblatt Großfeuerungen bereits aufgenommen.

17. Schlagwörter
Beste Verfügbare Techniken, BVT, IVU-Richtlinie, Großfeuerungsanlagen, Gasturbinen, Vermeidung; Minderung; Emissionen, Abwasser, Abfälle, Lärm

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1 Introduction

A central element to implement the IPPC-Directive (Council Directive 96/61/EC) consists in the information exchange on an European level on the “Best Available Techniques” BAT for all industrial activities listed in Annex 1 of the Directive. Technical Working Groups (TWG) are set up to facilitate the exchange of information under Article 16.2 of the Directive. The first TWG on large combustion plants (LCP - combustion installations with a rated thermal input exceeding 50 MW) was held on 24 and 25 February 2000 at the European IPPC Bureau (EIPPCB) in Sevilla. The aim of this working group is the elaborate a Reference Document on BAT (here: BREF) for this sector.

In order to support the work of the EIPPCB the German Federal Environmental Agency (UBA) decided to start a concerted investigation on operational experience with LCP in Germany. In close co-operation with the Federal States’ authorities plant operator were contacted to provide information on techniques which should be considered in the determination of BAT. A number of 44 plants in total were chosen to provide such examples. These plants cover all major combustion techniques and fuels used in this sector. They comprise new installations as well as retrofitted ones which demonstrate improved environmental and economical performance.

In April 2000 a questionnaire was sent out to the chosen LCP asking for information on technical characteristics, emissions into air, discharges to water, waste production, utilisation and disposal, emissions of heat and sound, economic issues and safety. By the end of the year 2001 there were 32 responses to this questionnaire which provide *measured data* from installations which are *currently operated* in Germany.

In the results from this concerted investigation are presented in two manners. In the first part the chosen large combustion plants are briefly described representing the most important plant types operated in Germany. These short outlines are based on the questionnaires and on supplementary material provided or published by the plant operators. Subsequently, general considerations are given which should be taken into account in an assessment of BAT. These considerations are given for each type of fuel and thy are completed by summary tables with emissions and emission limit values of the selected power plants.

The aim of this document is to provide the TWG with information from practice describing techniques to be considered in the determination of BAT.

2 Examples to be considered in the determination of BAT

2.1 Pulverised Coal Combustion

2.1.1 Example: Plant maintenance and reactivating of SCR catalysts in hard coal fired power plants

Description

The examples resumed here out of three different hard coal power plants shall show, how to extend the life cycle of SCR- catalysts by using sophisticated processes. The measures described implicate an operating of the SCR plants in an economically more reasonable way and provide less environmental impact because of the lower consumption of catalyst materials, which contain heavy metals.

Reasons for a deactivation of $DeNO_x$ catalysts can be:

- constipation by fly ash, deposit of ashes,
- formation of barrier layers, for example by gypsum,
- cations (sodium, arsenic) resp. anions (phosphate) “poison” the catalyst, which means they reduce the catalytic function of the active sites by their presence.

The measures summarised in Table 2-1 have been realized. Example A is a continuous cleaning of the catalysts by sound waves of 250 Hz while operating. The effect of this measure just provides the detaching of ash deposits and prevention of constipation of the catalyst grids. Poisoning of the catalyst by f. ex. arsenic are not prevented. Whereas the processes B and C can both avoid the formation of barrier layers and raise the activity of the catalysts by removing poisoning elements out of the catalyst material.

Table 2-1: Three examples for the maintenance resp. reactivation of SCR catalysts

Process [Reference]	A [1]	B [2]	C [3]
Description	maintenance by continuous treatment with sound waves of 250 Hz	process for regeneration for in-situ treatment during standstills periods of several days (about 3 to 5 days)	process for regeneration for ex- situ treatment of the catalysts by ultrasonic treatment and acid bath
Effect	detaching of ash deposits, prevention of constipation of the catalyst grids	removal of all reasons for deactivation (deposits, barrier layers, poisoning by arsenic, thallium, and phosphor)	removal of all reasons for deactivation (deposits, barrier layers, poisoning by arsenic, thallium, and phosphor)
Quantification of the effect	depositions and constipations can be prevented during 7 months of operation; steam blowers are not necessary	increase in activity from 65 to about 80 %, thus about 15 % points (in a first trial run)	increase in activity of 14 to 57 percentage points

For process A there are no further information available. Therefore, the following descriptions concentrate on the regeneration processes A and B.

The advantage of process B is that the catalyst can stay in place. However, it needs a standstill of about 3 to 5 days to realize the reactivation. In this process, the surface layer, which represses the gas diffusion, is removed at first by a washing agent with high pH-value. Then, while the pH-value is decreasing, the catalyst poisons are unhinged from the catalyst and removed from place. The rate of vanadium and tungsten removed unintentionally from the catalyst material is very low. Just a few per mille of these elements are taken out of it.

Figure 2-1 shows a schematic flow diagram of process C.

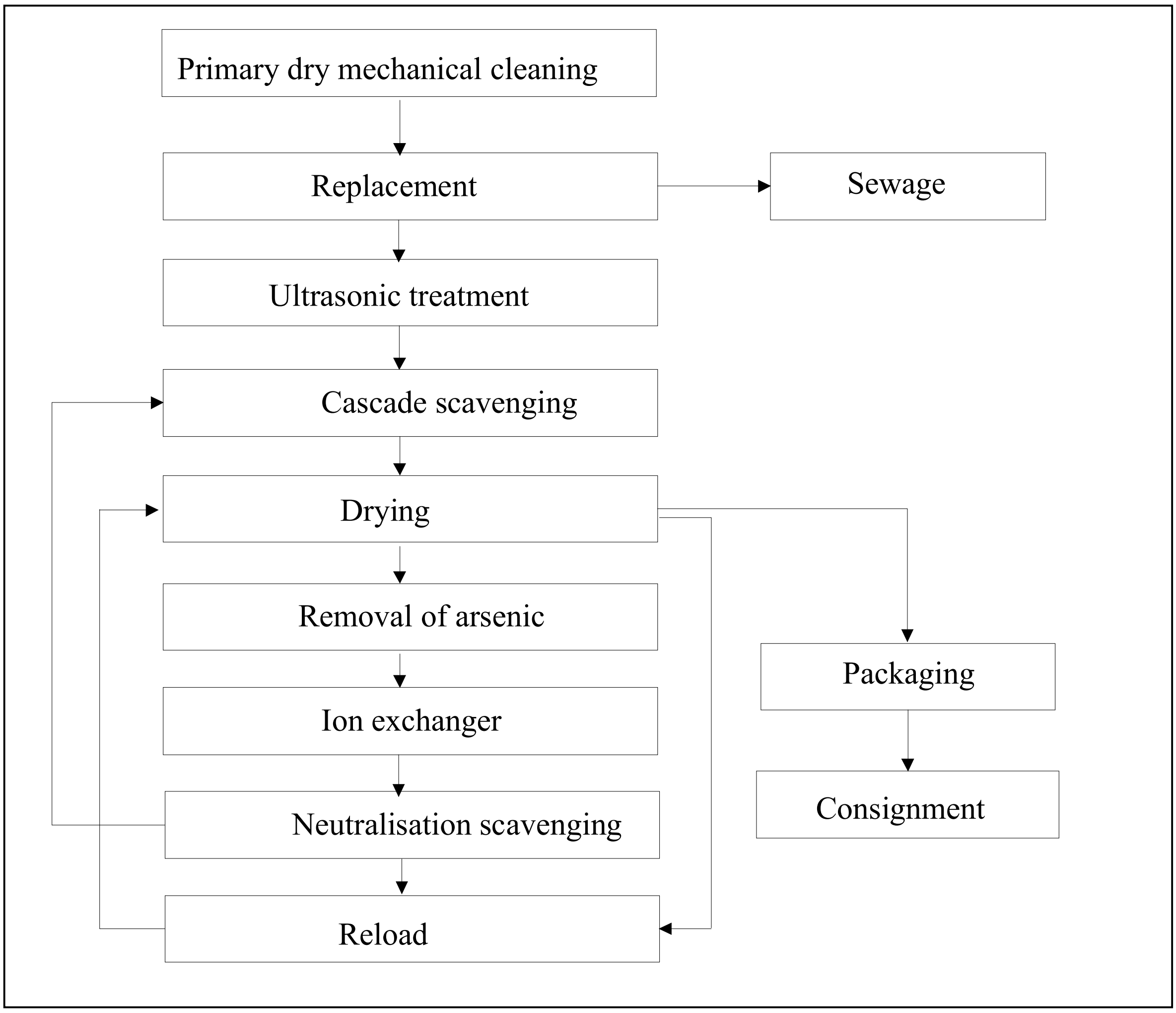

Figure 2-1: Schematic flow diagram of the ultrasonic regeneration process of SCR catalysts

One important aspect of this process is to find out exactly the reasons for deactivation of the catalyst, in order to optimise the design of the regeneration process. For this, the conversion rates for NO_x (here: “K- value”, K_0 is given for the virgin catalyst) and for SO_2/SO_3 are measured and an elemental analysis of catalyst body and surface is made.

The reactivation plant treats the SCR catalysts of several power plants and therefore achieves a turnover of up to 4 m³ of catalyst material volume per hour.

Main environmental benefits

The processes described here provide less environmental impact because of the lower requirement of catalyst material, which contains heavy metals and have a very energy-intensive production.

Applicability

Positive results for process A could be achieved in a pulverised hard coal fired plant. Process B has been tested in at least two pulverised hard coal fired combustions with positive results. For process C, experiences have been made in more than ten hard coal-fired power plants. In general, the implementation of these processes should be - apart from some modifications - possible for all SCR catalysts used in hard coal combustions.

Cross media aspects

For process A, no residues nor waste water occurs during operation. The energy demand is low compared to the alternative process of steam blowing. For process B, the suspension of the regeneration accrues, which can contain arsenic, vanadium, tungsten, calcium, iron and other elements. In a first trial run, this waste water could be treated without any problems in the FDA waste water treatment plant existent on site. There was no special licence needed for this process.

For process C, a considerably high energy input is necessary. However, exact values for this are not available. Further on, waste water flows, charged partly with vanadium and arsenic, are accruing at several process stages and have to be treated.

Operational data

Most experience is available for process C. So, in Table 2-2, the results of regeneration processes in eleven power plants are summarized. It shows, that apart from one exception the activity could be increased by 13.8 to 57.2 percentage points. The absolute activity after regeneration achieved between 68 and 105 % of the virgin activity. Furthermore, Figure 2-2 illustrates the dependence between increase in catalytic activity and the activity before regeneration. One recognizes, that positive results are achievable only for residual activities below 80%. But it is also recognizable that in some cases, the activity could be increased up to the level of the virgin catalyst material.

Table 2-2: Results for regenerations for process C

Power plant example number	K_{before}/K_0 [%]	K_{after}/K_0 [%]	Enhancement by regeneration [%-points]
1	60.1	96.1	36.0
2	66.1	93.2	27.0
3	47.8	105.0	57.2
4	58.0	89.3	31.3
5	83.9	81.9	-2.0
6	34.3	68.3	34.0
7	61.1	75.0	13.9
8	32.8	86.0	53.3
9	54.1	74.7	20.6
10	54.2	94.8	40.6
11	79.7	79.4	-0.3

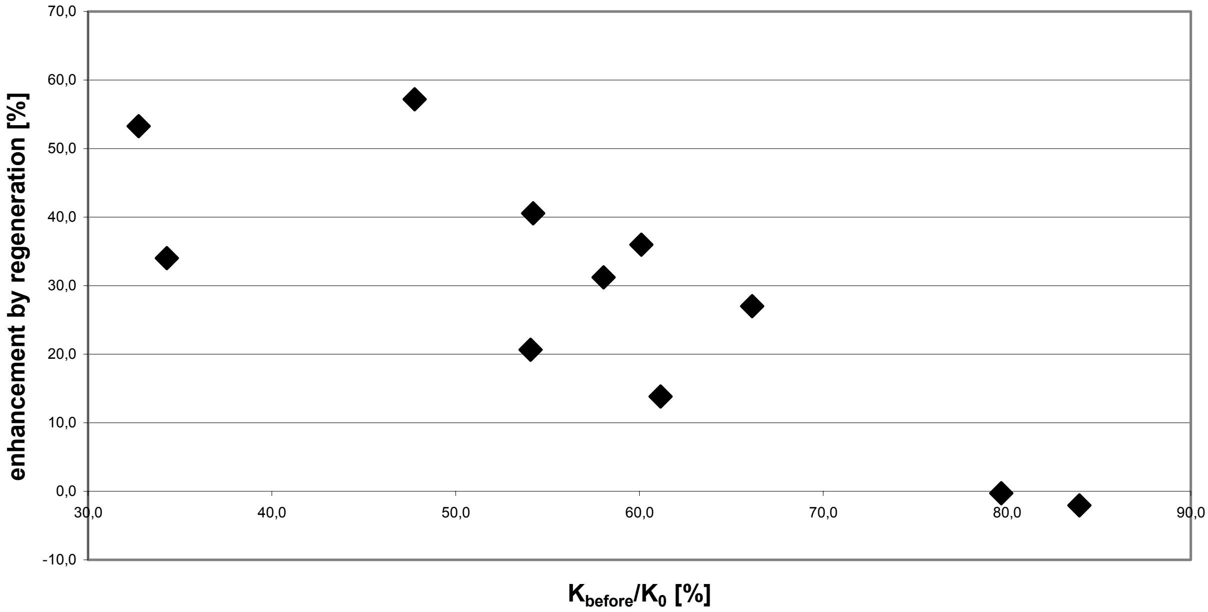

Figure 2-2: Dependence of increase of catalyst activity and the activity before regeneration for process C

For process B, the operational data are yet not as detailed as for process C. Results of measurements in pilot plants show enhancement of the activity of 8 to 15 % at a residual activity level before the regeneration of 70%. In the first trial run, at a residual activity level of 65 %, an increase in activity up to 78 % could be achieved. These results induce, that process C will deliver similar results as process B. Whether increases of this extend will be able with process B also for such low residual activities, as realized with process C, is not sure.

For both of the processes, the results induce the possibility of several regenerations of the same catalyst material. Further, the calalyst activity of regenerated materials is similar to virgin catalysts.

Economic data

Economical data are available only for process C. In a concrete example, the annual running costs for the SCR plant with regeneration were compared to a plant with exchange of the catalyst.

Option	Running costs [10^3 DM/a]	Costs including debt service [10^3 DM/a]
Operation with 3 catalyst layers / replacement with virgin material	1,358	1,921
Operation with 4 catalyst layers / replacement with virgin material	1,288	1,585
Operation with 3 catalyst layers / reactivation	718	987

As process B requires far less input compared to process C, the savings in running costs for process B are supposed to be even higher.

Driving force for implementation

The reason for the development and implementation of processes for regeneration is the savings resulting from the avoided costs for catalyst materials.

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„Kraftwerke 2000“ vom 10. – 12. Oktober 2000 in Düsseldorf, Herausgegeben von der VGB Technische Vereinigung der Großkraftwerksbetreiber e.V.

2.1.2 Example: Pulverised coal fired dry bottom boiler with high efficiency and flue gas cleaning

Description

The power plant was commissioned in 1994 and has a rated thermal power input of 1,370 MW. The maximum power output is 553 MW_{el} gross electricity, 508 MW_{el} net electricity and 300 MW of heat. The electrical net efficiency is 42.5 % in the design point.

The coal from the world market is grinded in four coal mills before being burned in 16 staged turbulent burners. The burners are located at 4 levels.
After cleaning, the flue gas is released to the atmosphere via the cooling tower of 141.5 m height.
The turbine steam parameters amount to 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 in one line

Primary measures for NO_x reduction

- Low-NOx-burners allow for concentrations of NO_x in the raw gas < 500 mg/Nm^3
- SCR installation with three catalyst layers realised in “high-dust” position

Desulphurisation

Wet FGD using chalk as absorbent; without reheating; separation efficiency > 95 %

Dust control

ESP with separation efficiency > 99 %

Main environmental benefits

The high electrical net efficiency allows for economical use of resources and low specific CO_2 emissions.
Primary and secondary measures lead to low atmospheric emissions.

Applicability

A potential site for installing a plant of the described type requires a demand for district heat, sufficient water resources and transport facilities for the coal.

Cross media aspects

The residues accruing from the flue gas cleaning are:

- fly ash (electrostatic precipitator)
- wastewater and gypsum from the desulphurisation plant

Furthermore, the catalyst of the SCR plant needs to be replaced periodically.

The operation of the desulphurisation unit reduces the electrical net efficiency.

Operational data

In 1999 the plant was in operation for 5,782 hours and produced 2,481.3 GWh_{el} 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 2-3 shows the atmospheric emissions of the coal-fired boiler and the gas turbine in 1999.

Table 2-3: Emission limit values and measured emission levels in 1999

	ELV (1/2-hour mean value at 6 % O_2)	Measured emission level	Specific emissions [g/MWh_{el}]	Measurement
O_2-Content [%]		4		
Operation mode		Full load		
Flue gas volume flow rate [m^3/h]		1,580,000		
Dust [mg/Nm^3]	20	3	9.11	continuous
SO_2 [mg/Nm^3]	200	52	158.38	continuous
NO_x [mg/Nm^3]	200	167	483	continuous
CO [mg/Nm^3]	200	23	66.49	continuous
HCl [mg/Nm^3]	20	< 1.73		individual
HF [mg/Nm^3]	2	< 0.2		individual

Some 782 kilotons of hard coal from the world market were fired in 1999. Additionally 4,170 tons of light fuel oil were fired.

The consumption of the most important auxiliary supplies are shown in Table 2-4.

Table 2-4: Consumption of important auxiliary supplies in 1999

Auxiliary material	Application	Consumption [t/a]	Specific consumption [g/MWh$_{el}$]
Chalk White fine lime	FGD	16,139 588	6,500 237
H_2SO_4	Water treatment	603	244
$FeCl_3$		396	159
NH_3PiaNO$_x$	SCR	605	244

The cooling system is fed with water from the Baltic sea. It is used without any demineralisation. To prevent corrosion the tubes of the cooling system are completely made of titanium. The thickened cooling water is dumped back to the sea with a flow rate of 950 m^3/h at full load. the concentrations of impurities in this effluent are shown in Table 2-5.

Table 2-5: Concentrations of impurities in the effluent of the cooling system (measurements in 1999; mean values)

	Mean concentration [mg/l]	Specific load [g/MWh$_{el}$]
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

The water demand of the wet FGD was covered with a mix of sea water and source water. The treatment of the effluents of the FGD produces wastewaters (70 m^3/h) which are also discharged to the sea. The concentrations of impurities in the wastewater of the desulphurisation plant after treatment are shown in Table 2-6.

Table 2-6: Concentrations of impurities in the wastewater of the desulphurisation plant after treatment (measurements in 1999; mean values)

	Limit values [mg/l]	Mean values of concentration [mg/l]	Specific load [g/MWh$_{el}$]
AOX		0.0383	0.002
COD	150	71	3.57
Zink	1	<1	0.05
N_{total}		<10	0.5
Cr	0.5	<0.01	
Cd	0.05	<0.01	
Cu	0.5	<0.01	
Pb	0.1	<0.1	0.005
Ni	0.5	<0.02	
Filterable matter	30	<30	1.5
Sulphate	2000	<2000	100.7
Sulphite	20	<20	1.00
Fluoride	30	<30	1.5
Mercury	0.05	<0.001	
Sulphide	0.2	<0.2	0.1

Table 2-7 shows the quantities of residues produced in 1999.

Table 2-7: Residues generated in 1999

	Quantity [t/a]	**Specific Quantity [kg/MWh$_{el}$]**	**Re-use/ Disposal**
Bottom ash	14.150	6	Building material industry
Fly ash	81.350	30	Building material industry
FGD gypsum	26.300	10	Building material industry
C-Gypsum	2.020	0.8	Waste site cover
Sludge from cooling tower makeup water treatment	733	0.3	Waste site cover

The legal requirements for sound control are adapted to the residential site which is about 820 m away from the plant. These levels can be reached with the help of exhaust silencers, acoustic screens, encapsulations and by avoiding periodically changing forces and pressures.

Economic Data

The total investment amounted to 615 Mio EUR at the time of commissioning. That relates to a specific investment of 1,118 EUR/kW$_{el}$.

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. The optimisation of the efficiency was primarily realised for economical reasons.

2.1.3 Example: Pulverised hard coal firing with dry bottom boiler and emission control in a CHP-plant

Description

The presented CHP-plant was commissioned in 1989 and has a maximum rated power input of 1,278 MW_{th}, an electrical gross capacity of 383 MWel and generates up to 550 MW_{th} district heat. These values result in an electrical gross efficiency of 39.1 % and an overall gross energy efficiency of 73 % at rated load. In most cases, the thermal input to reach the given power output is below 1278 MW, depending weather conditions and fuel quality. A change in the fuel quality results also in a change of the efficiency.

The steam parameters of the high pressure steam amount to 255 bar / 535 °C and 63 bar / 241 °C after reheating. Primary NO_x-control comprises Low-NO_x-burners and flue gas re-circulation. The SCR installation was installed in high-dust configuration. The ESP is situated between the air preheater and the desulphurisation plant which is realised as a wet FGD operating with grinded limestone. After the desulphurisation the flue gas must be reheated before it can be emitted via stack. The cooling system works with a 132 m high natural draught cooling tower. To prevent diffuse emissions, coal shipping is carried out in a hall and all the band conveyors are encapsulated.

Main environmental benefits

Primary and secondary measures ensure low atmospheric emissions. The cogeneration of heat and power leads to a high overall energy efficiency.

Applicability

The utilisation of the presented techniques only depends on local conditions, such as supply with fuel and cooling water and demand for power and heat.

Cross media aspects

The incidental residues of the flue gas cleaning are:

- fly ash (electrostatic precipitator)
- wastewater and gypsum from the desulphurisation plant

Furthermore the catalyst of the SCR plant needs to be replaced periodically.

The operation of the desulphurisation system and other secondary measures reduces the electrical efficiency.

Operational Data

In the year 1999 the plant was in operation for 7,289 hours, the equivalent full load hours amounted to 5,534.

Table 2-8 shows the atmospheric emissions in 1999.

Table 2-8: Emission limit values and measured emission levels in 1999

	ELV (*1/2-hour mean value at 6 % O_2)	Measured emission level	Specific emissions [g/MWh$_{el}$]	Monitoring
O_2-Content [%]		6		
Operational state		full load		
flue gas volume flow rate [m^3/h]		1,635,000		
Dust [mg/Nm³]	50	7.3	2.59	continuous
SO_2 [mg/Nm³]	400	254	90.28	continuous
Sulphur emssion rate [%]	15	8.6		
NO_x [mg/Nm³]	200	192	68.24	continuous
CO [mg/Nm³]	200	17	6.04	continuous
NH_3 [mg/Nm³]	10	0.5	0.18	individual

Some 1,168 kilotons of hard coal (=6,714 GWh), 8,140 tons of heavy fuel oil (=93 GWh) and 304 GWh of coke gas were fired in 1999.

Data concerning the fired hard coal is put together in Table 2-9.

Table 2-9: Parameters of the fired hard coal in 1999

Heating value [kJ/kg]	Ash content [%]	Water content [%]	Sulphur content [%]
20,689	26.5	10.9	1.09

The wet FGD consumed about 8.5 t/h of lime (47 kt/a) and produced about 13.5 t/h of gypsum (about 75 kt/a). About 300 kilotons of ash were produced in the reference year.

The sources for wastewater are the full water softening plant, the treatment of the condensate, the cooling water effluent and the wet FGD. The wastewaters which result from the regeneration of the full water softening plant and from the regeneration of the condensate treatment plant are both neutralised and dumped to the preclarifier. This wastewater flow amounted to 14,800 m^3 in 1999. The wastewater from the wet FGD is treated with precipitation, flocculation and sedimentation before it is dumped to the preclarifier (222,922 m^3 in 1999). The effluent of the cooling circuit is dumped without any treatment

(2,980,000 m^3 in 1999). The total wasterwater flow rate at full load amounts to 1,327 m^3/h. A share of 327 m^3/h is treated before it is dumped.

Economic data
There is no data available.

Driving force for implementation
Primary and secondary emission control was realised to comply with emission limit values.

2.1.4 Example: Pulverised hard coal fired dry bottom boiler with simultaneous reduction of NO_x and SO_2 within the DESONOX- process

Description
This plant consists of two units for hard coal fired boiler, which started up in 1976 (unit II) and in 1984 (unit III) within a combined heat and power plant with a rated thermal input of 92 / 94 MW and a gross energy output maximum of 25 / 27.5 MW_{el} , respectively. While operating in combined heat and power production, a gross energy output of 18.8 / 27.5 MW_{el} and net energy output of 15.1 / 22.8 MW_{el} are possible. Up to 114 MW_{th} can be used for district heating. The withdrawal for district heating is realised by a condensing steam turbine with bleeding in unit II, whereas in unit III a backpressure turbine is installed, which delivers district heat by condensers.
Unit I is operating with gas and oil at an rated thermal input of 92 MW and will not be described here further on.
The boiler is fired at two levels with four burners for pulverised hard coal respectively (corner firing). The boiler works at natural circulation.
The hard coal is delivered by ship and stored in silos containing up to 15,000 t of hard coal. The flue gas leaving the DESONOX- process is dissipated by a stack. The plant was retrofitted with this process in 1990 (unit II) and 1988 (unit III). It was the first time, this process had been implemented.

DESONOX process
Figure 2-3 shows a schematic flow diagram of this process for unit II. After leaving the combustion zone, the flue gas is cooled off by a rotary air heater in order to obtain the operating temperature of the electrostatic precipitator. The dedusted flue gas is reheated by a heat exchanger and a gas burner. For unit III no reheating is necessary because this electrostatic precipitator works at high temperatures, which allows to hold the flue gas temperatures at a level of about 470°C, which is the temperature needed for the DESONOX process. At the entry of the reactor ammonia is injected. The chemical reaction consists of a denitrification process at first stage, followed by a catalytic oxidation process of SO_2 to SO_3.

Subsequently the purified flue gas passes two heat exchangers, connected in series. The sulphur trioxide reacts with the steam to droplets of sulphuric acid and is separated from the flue gas flow by condensing partially in the second heat exchanger, two- stage wet scrubber and a wet electrostatic precipitator. In addition to this, the wet scrubber is combined with a stripper, which reduces the concentration of halogen substances by depositing water containing chlorine and fluorine substances. This waste water flow is neutralised with lime and dissipated. The halogen substances, $CaCl_2$ and CaF_2, are held back by a filter. After leaving the second heat exchanger, the flue gas is reheated and dissipated via stack (figure 1-3). The quality of the produced sulphuric acid with a concentration of 70%, is accepted by several industrial consumers and is at the time used for the production of fertilizer. The removal efficiency is shown in Table 2-10.

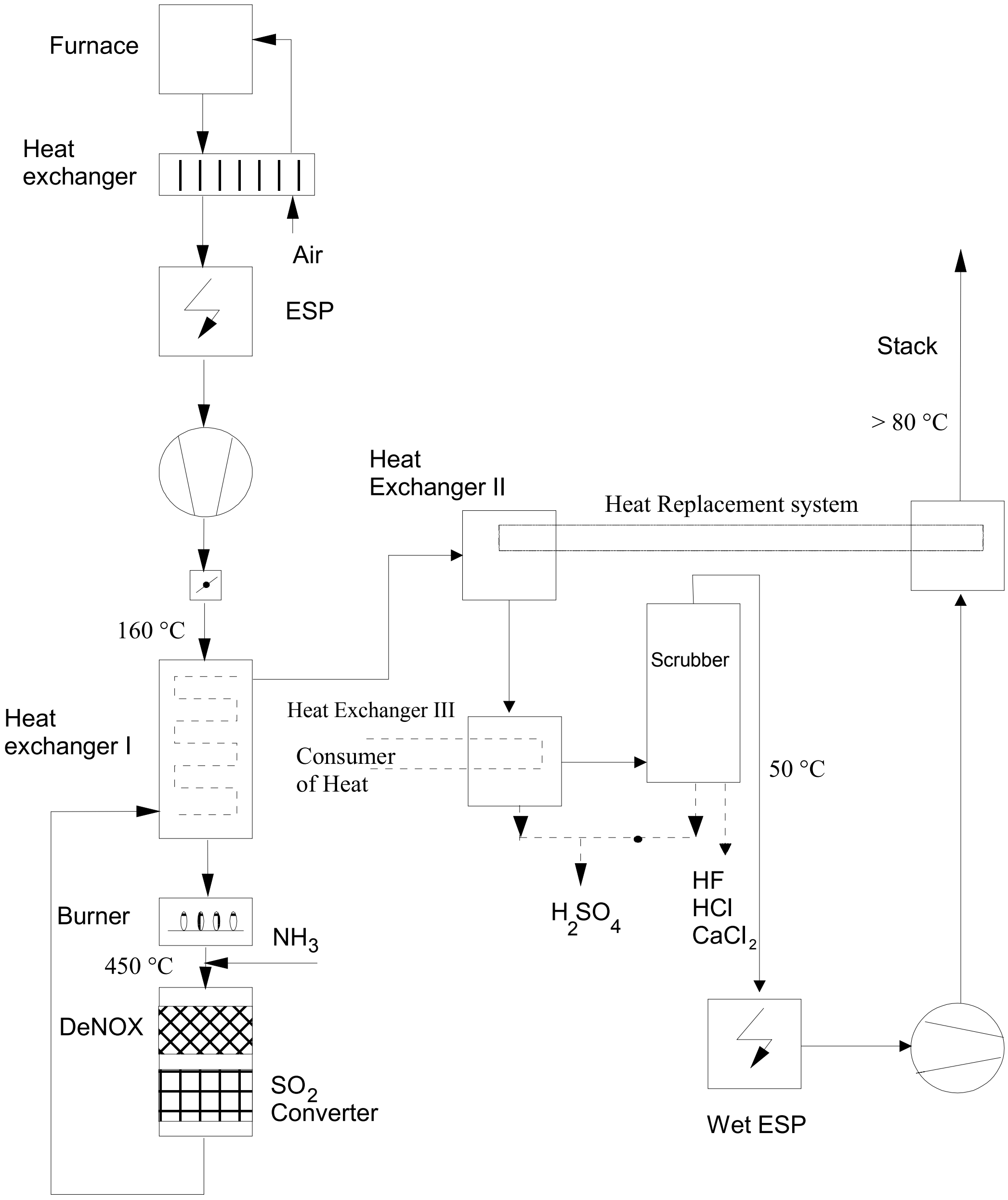

Figure 2-3: Schematic flow diagram of the DESONOX-process

Main environmental benefits

The process described here has a high separation efficiency for SO_x, NO_x, HCl, HF and particles compared to the size of the plant. In addition to this, no waste but marketable sulphuric acid is produced.

Applicability

As the DESONOX process is only implemented in one plant, there are no restrictions known for the implementation of the process in other coal fired plants.

Cross media aspects

The residues accruing from the flue gas cleaning are:

- Electrostatic precipitator: fly ash
- DESONOX: waste water → neutralisation
  sulphuric acid → utilisation for the production of fertilizer

The energy demand of the flue gas cleaning plant demands 1 MW_{el} at each unit and therefore reduces the electrical overall efficiency by about 4 to 5 percentage points.

Operational data

Unless otherwise specified all the data given in Table 2-10 apply to the plant in general, units I-III. In 1999, the two coal fired units produced 105 $GWh_{el,netto}$. At the same time, 430,617 GWh of district heat were delivered. The annual net efficiency was therefore at 76%, the mean net electrical efficiency at about 17.2 %. The generating units operated for 4,327 and 4,097 hours respectively. They reached 2,586 and 2,905 operating hours at full load. This is a relatively weak result, but it can be explained by the fact that the main focus is on the district heating. In 1998, the measurement of atmospheric emissions showed the following results:

Table 2-10: Limit values and measured data of atmospheric emissions in 1998

	ELV (at 6% O_2)	Raw gas concentration (all boilers)	Boiler II		Boiler III	
			Measured value (DMV = AMV)* at 6% O_2	Specific value [kg/TJ_{input}]	Measured value (DMV = AMV) at 6% O_2	Specific value [kg/TJ_{input}]
O_2-concentration of the flue gas [%]			9		9	
Operating condition			at full load		at full load	
Flue gas volume [m^3/h]			114,856		125,665	

Dust [mg/Nm^3]	20		-			
SO_2 [mg/Nm^3]	270	1,700	128	44,10	52.7	19.6
NO_x [mg/Nm^3]	200	1,000	158.4	54.60	154.8	57.5
CO [mg/Nm^3]	250		18.2	6.30	31.2	11.6
HCl [mg/Nm^3]	100	186				
HF [mg/Nm^3]	15	10	< 10	< 3.4	< 10	< 3.4

*DMV: daily mean value; AMV: annual mean value

In 1999, 31,070 tons of hard coal were used in unit II respectively 33,451 tons in unit III. The hard coal had a mean water content of 7 %, sulphur content of 1 % and an ash content of 7%. In addition to this, 780 t (unit II) and 719 t (unit III) of light fuel oil were utilised. Consumption of the important auxiliary supplies in 1999 is given in Table 2-11. Except the consumption of ammonia for the DESONOX plant, all data applies to the whole of the plant, including units I-III.

Table 2-11: Consumption of important auxiliary supplies in 1998

Auxiliary material	Utilization	Consumption [t/a]	Specific consumption [kg/TJ_{in}]
Ammonia	DESONOX	158	54.3
Slaked lime	neutralisation	52	17.9
Hydrochloric acid	desalination	29.9	10.3
Sodium hydroxide	desalination	20.2	6.9
Grease / oil	lubricant	18	6.2
Ammonia	feed water	0.55	0.19
Ferrofos 528	cooling water	1.12	0.38
Bayrolyt	cooling water	0.81	0.28

In 1998 the consumption of water for the once- through cooling amounted to 15.5 Mio. m^3. This volume flow was derived from the preclarifier and was given back untreated except the addition of small amounts of conditioners. Furthermore, 91,256 m^3 of drinking water were used for the plant (feed water, primary cooling system, DESONOX) of which 39,922 m^3 were given back untreated, whereas 14,600 m^3 were dumped in indirectly after passing a neutralisation processes. 13,023 m^3 of this volume flow come from the neutralisation process of the DESONOX plant and 1,638 m^3 from the neutralisation of the water treatment plant. Table 2-12 shows the concentration of substances in the effluent of the waste water treatment and the DESONOX process.

Table 2-12: Concentration of substances in the effluent of the neutralised waste water from the waste water treatment and the DESONOX process

	Arithmetical mean of 4 measurements [mg/l]	Load [g/TJin]
Chlorine	3,940	1.98E+04
Zink	0.05	2.51E-01
Chromium	0.006	3.01E-02
Cadmium	0.0006	3.01E-03
Copper	<0.005	< 2.51E-02
Lead	<0.005	< 2.51E-02
Nickel	0.006	3.01E-02
Fluoride	5.45	2.73E+01
Mercury	0.01	5.02E-02
Sulfide	< 0.01	< 5.02E-02

Table 2-13 shows the quantities of residues produced in 1998.

Table 2-13: Residues generated in 1998

	Boiler ash	Fly ash	Sulphuric acid
Quantity [t/a]	1,404	3,716	2,808
Specific Quantity [g/MWh$_{el}$]	482	1,277	965
Utilisation / Disposal	industry for building materials	industry for building materials	chem. industries, fertilizer

Economic data

The total investment for the original plant as a whole amounted to 103 Mio. €. The dedusting plants required another 2 Mio. € of investment. For the DESONOX plants, the investment mounted up to 37 Mio. € whereof the first of the two plants was of lower cost (13.8 Mio . € in 1988) than the second with 23 Mio. €. This is due to an additional heat exchanger necessary for the second one. Furthermore, the second plant was not subsidised anymore. In Table 2-14, economical data is shown more detailed of the DESONOX plant which started operation in 1988.

Table 2-14: Details of the operational costs of a DESONOX plant (monetary value of 1988)

Capacity	92 MW$_{th}$
Investment	$13.8 \cdot 10^6$ €
Operating hours at full load	5,000 h/a
Capital cost	$2 \cdot 10^6$ €/a

Variable costs	$0.5 \cdot 10^6$ €/a
Maintenance and repair	128,000 €/a
Replacement of the catalyst	230,000 €/a
Personnel costs	205,000 €/a
Sum of costs	$3 \cdot 10^6$ €/a

Driving force for implementation

In the middle of the eighties, the DESONOX plant was implemented because of its possibilities of reducing SO_2 and NO_x simultaneously. At this time, methods for secondary reduction of NO_x were still under development. Further on, the plant operators were searching for processes with recyclable and marketable by- products as the sulphuric acid is in this case. Though using a wet limestone scrubber for desulphurisation, gypsum and therefore also a recycable product is produced. But this by- product out of plants of this size is often of minor quality and has to be deposited.

2.1.5 Example: Pulverised hard coal-fired dry bottom boiler – retrofitting of primary NO_x control and secondary desulphurisation and NO_x abatement

Description

The presented plant was commissioned in 1983 and has a rated thermal input of 1,820 MW, a gross electrical power of 750 MW_{el} and a mean electrical net power of 675 MW_{el} in 1999. It was equipped with a wet limestone scrubber (removal efficiency > 85 %) and a SCR-system between 1983 and 1989. The electrostatic precipitator reduces emissions of dust 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.

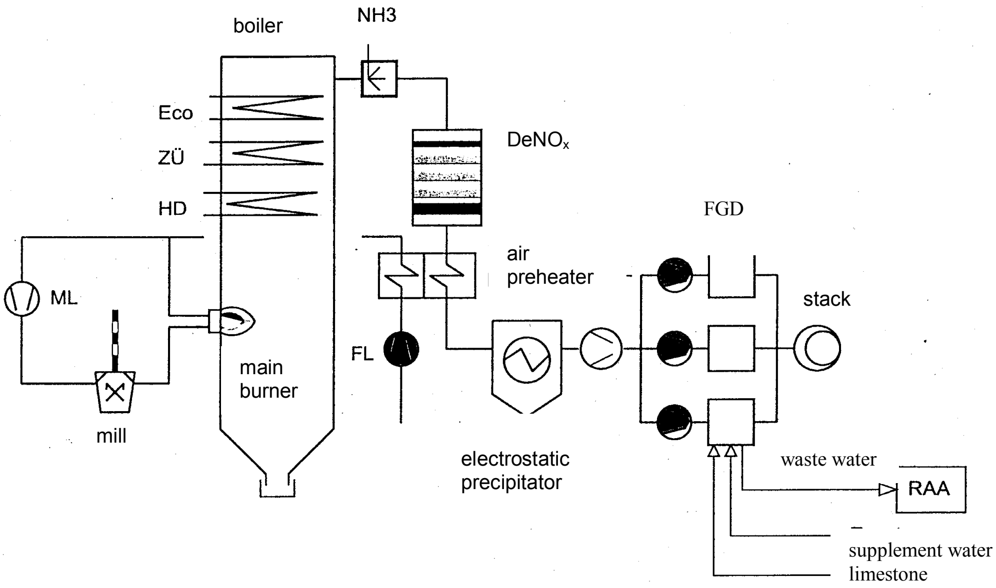

Figure 2-4: Schematic overview of the boiler and the flue gas path

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, reduced need of power for the induced draught system and a higher boiler efficiency due to lower excess air. Compliance with emission limit values for NO_x had already been achieved with the existing SCR system.

The superposition of an axial and a radial air staging allowed for the area close to the furnace wall a high content of O_2 and a low content of CO. This offered an efficient protection against corrosion. Due to low-NOx 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 2-15.

Table 2-15: Comparison of relevant operation data before and after retrofitting of primary NO_x control measures

Parameter	Unit	Operation data before retrofitting	Achieved operation 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	%	ca. 1	2 – 3
Consumption of ammonia	kg/h	600	< 275
Minimum catalyst activity	m/h	21	n. a.
Power demand of			
fresh air fan	kW	5,600	n. a.
induced draught system	kW	5,420	
desulphurisation fan	kW	3,400	
Temperature of exhaust gas	°C	130	ca. 128
Boiler efficiency	%	92.53	> 92.83
Reheater injection	%	1.7	ca. 0.3

The saved power demand sums up to 2.53 MW_{el}. That means 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, resulting in an additional increase of the electrical net efficiency of 0.2 percentage points. This was not implemented due to lacking economical efficiency. The old coal mills were not changed. New ones could have diminished the content of combustible matter in the fly ash.

Main environmental benefits

The described retrofitting of the boiler reduced the consumption of auxiliary materials like ammonia and the electrical power demand. This accounted for a saving of 2 tons of CO_2 per hour. The flue gas cleaning systems, the wastewater treatment and the electrical net efficiency are in line with the state-of-the-art of German power plants.

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. Retrofitting of a boiler cannot be standardized and must therefore be planned individually.

Cross media aspects

The flue gas cleaning produces ash (electrostatic precipitator), wastewater 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 5,855 hours and produced 3,107.3 GWh of electricity with electric efficiency of 37.1 %. The net electric efficiency at the design point is 38.3 %. The following atmospheric emissions were measured.

Table 2-16: Emission limit values and measured atmospheric emissions in 1999

	ELV at 6 % O_2	Measured emission levels	Specific emissions [g/MWh$_{el}$]	Measurement
O_2-Content [%]		7		continuous
Operational state		Full load		
Flue gas volume flow rate [m^3/h]		2,500,000		
Dust [mg/Nm^3]	100	< 10$^{1)}$	37	continuous
SO_2 [mg/Nm^3]	400	150$^{1)}$	556	continuous
Sulphur emission rate [%]	15	10		continuous
NO_x [mg/Nm^3]	200	190$^{1)}$	704	continuous
CO [mg/Nm^3]	250	12$^{1)}$	44	continuous
HCl [mg/Nm^3]	100	< 30		individual
HF [mg/Nm^3]	15	< 3		individual

1) annual mean value at 6 % O_2, equivalent to daily mean at normal operation

Fugitive emissions arise from storage and handling of coal. Annual emissions were estimated to 102 kg/a. For emission reduction an encapsulation of the coal discharge station and an underground coal conveying system was installed.

1,081.5 kilotons of hard coal from two German mines and 3,597 t of heavy fuel oil were fired. The characteristics of the coal used is shown in Table 2-17.

Table 2-17: Average characteristics of the fired hard coal

H_u [MJ/t]	26,500
Water (Lfg) [%]	8
Sulphur content (Lfg) [%]	0.7 – 0.9
Ash content (wf) [%]	7.5 - 10
Volatiles (wf) [%]	32 - 38
Nitrogen (waf) [%]	0.9 – 1.6
Grain diameter [mm]	0 - 20
Grindability, Hardgrove [°H]	42 - 55
Cl (wf) [%]	< 0.45

The wastewater flow rate of the whole plant amounts up to 280 m^3/h. Some 80 m^3/h originate from the condensate treatment and other sources of the steam generation. After neutralisation and sedimentation this wastewater is discharged to the adjacent river with mean concentrations of impurities as shown in Table 2-18. Water from the cooling tower (160 m^3/h) is released to the river without any treatment. After neutralisation, precipitation, flocculation, sedimentation, biological treatment and filtration, wastewaters from desulphurisation (40 m^3/h) are dumped to the adjacent river with mean concentrations of impurities as shown in Table 2-19.

Table 2-18: Concentration of impurities in the wastewater from condensate treatment and other sources of the steam generation process

	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_{el}]		4.26	0.11	2.25			0.026		
Statistics of the value		Mean	Median	Median			Median		
Limit value [mg/l]	0.15-1	30-80	1.5-5	10	0.5	0.05	0.5	0.1	0.5

Table 2-19: Concentration of impurities in the wastewaters from the desulphurization 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_{el}]	1.9	68		0.5				
Statistics of the value	Median	Median		Median			Median	Median
Limit value [mg/l]	30	2.000	20	30	0.05	0.2	0.05	0.5

Table 2-20 shows the quantities of residues produced in 1999. Gypsum was not taken into account.

Table 2-20: Residues generated in 1999

	Classification of residues in Germany (Krw-/AbfG)	Quantity [t/a]	Specific quantity [kg/kWhel]	Utilisation / Disposal
Bottom ash	"no need to be monitored"	6,050	2.00E-03	landscape architecture, dump
Fly ash		7,100	2.28E-03	landscape architecture, dump*
Sludges from water treatment		6,611	2.13E-03	landscape architecture, dump
Filters and insulation materials		26	8.37E-06	Landfill
Sludges from wastewater treatment	"need to be monitored"	681	2.19E-04	Internal use
Waste oil, oil contaminated materials	"important need to be monitored"	34	1.09E-05	Incineration

*as far as not marketed

The legal requirements for sound result from the residential site which is situated 300 m away from the plant. Measures to reduce the emission of sound comprise acoustic absorbers, encapsulation of single installations, acoustic screens around the cooling tower and overhead noise barriers.

Economic data

The total investment for the plant amounted up to 791 Mio. EUR including the flue gas cleaning systems (1983 – 1989). The electrostatic precipitators accounted for 39.5 Mio. EUR, the retrofitted desulphurisation for 111.2 Mio. EUR and the retrofitted SCR for 38 Mio. EUR. The described retrofitting for primary NO_x reduction required an investment of 6 Mio. EUR. The investment for fugitive emission control (encapsulation of the coal discharge station and an underground coal conveying system) amounted to 12.5 Mio. EUR.

Driving force for implementation

The reason for the retrofitting of the boiler is the improved economical 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.

2.1.6 Example: Pulverised hard coal fired dry bottom boiler and compound operation with a gas turbine – district heating power plant with flue gas cleaning

Description

The coal-fired boiler is steam-side coupled with the hot exhaust gas of the gas turbine. This compound operation allows for high power values and efficiencies at different loads as shown in Table 2-21.

Table 2-21: Performance data at different operational states

Operation mode	Electricity only		Cogeneration of heat and power			
	P_{el} [MW]	$\eta_{el,net}$ [%]	P_{el} [MW]	$\eta_{el,net}$ [%]	P_{heat} [MW]	overall efficiency factor [%]
Compound 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

The coal from the world market is grinded in six coal mills before being burned in 12 staged combination burners. The single-draft boiler (Benson) has three burner levels. After cleaning, the flue gas is released to the atmosphere via a stack of 250 m height made of reinforced concrete together with an acid-resistant lining inside. The turbine steam parameters amount to 247 bar/ 545 °C and 61 bar / 565 °C after reheating. The 42 m high hybrid wet-dry cooling tower emits up to 420 MW of heat. The gas turbine with a rated thermal input of 184 MW is equipped with 24 hybrid burners in an annular ring combustion chamber. The turbine gas conditions amount to 17 bar / 1,160 °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 atmosphere without any further cleaning.

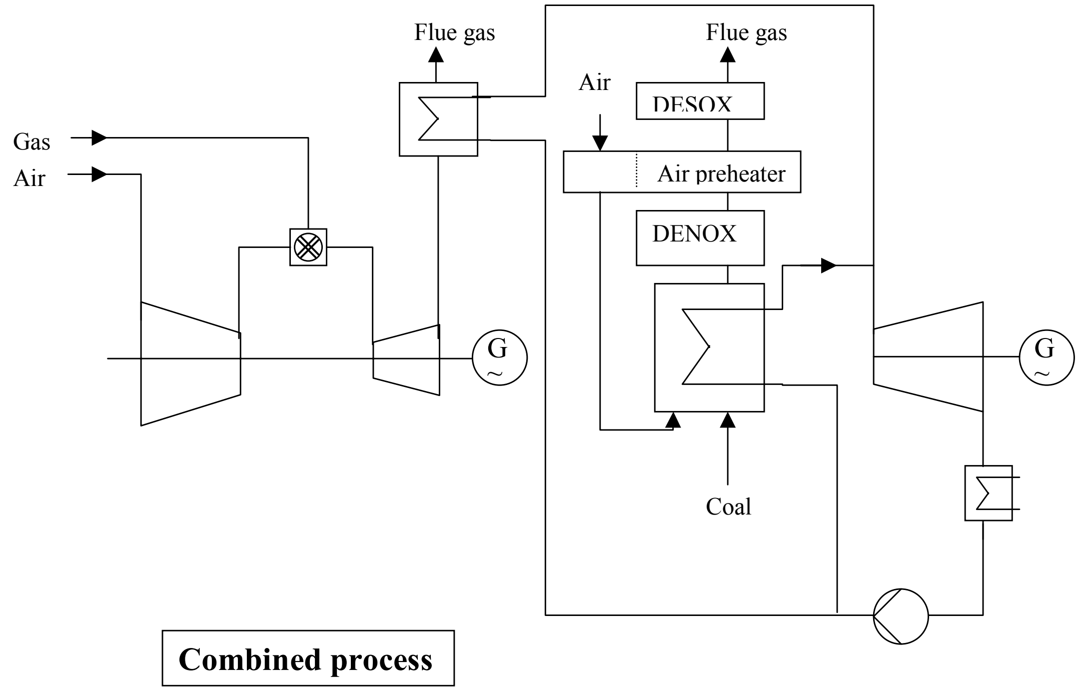

Figure 2-5: Schematic overview of the combined process

Measures for an optimised performance

The electrical net efficiency of up to 44 % and the overall efficiency factor of up to 70 % for compound operation were realised by the following individual measures:

- compound 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 (the hot flue gas of the gas turbine is used as combustion air in the coal-fired boiler) the presented process can reach high efficiencies also at part load conditions. The net efficiency remains at its maximum at 50 % load and still reaches a value of 40 % at 25 % load.
- high parameters for the turbine steam conditions
- optimised turbines
- reduced auxiliary power requirements (efficient desulphurisation and induced-draught system)
- sevenfold regenerative feed water heating (247 °C)
- high boiler efficiency (94.4 %)
- optimised condenser
- highly efficient gas turbine (36 % net efficiency)

The hybrid wet-dry cooling tower was installed to prevent shades over the nearby residential site. The required venting system shows an electricity demand of up to 3 MW_{el}.

Measures to reduce NO_x emissions

With the help of 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 of two units with a total volume of 250 m^3. The ammonia consumption can be up to 100 kg/h.

Desulphurisation

The wet limestone scrubber with a removal efficiency of 96 – 98,5 % is made of high alloy steel. The pipes and tubes are made of epoxy-glass resin.

The power consumption of the system arises to 3,4 MW_{el}. The vacuum filter dewaters the gypsum to a water content of 10 %.

Dedusting

Four electrostatic precipitator lines with a total area of 61,400 m^3 reduce the dust load by 99,92 %.

Main environmental benefits

The implementation of the compound technique allows for high efficiencies at different loads and operation modes. Primary and secondary measures lead to low atmospheric emissions. The re-use of wastewater reduces the water consumption (waste water from the ash water treatment and 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 described plant type a demand for district heating, sufficient water resources and transport facilities for the coal are the requirements for a potential site. The decision for retrofitting of an existing coal-fired boiler with a gas turbine depends on local conditions.

Cross media aspects

The incidental residues of the flue gas cleaning are:

- fly ash (electrostatic precipitator)
- wastewater and gypsum from the desulphurisation plant

Furthermore the catalyst of the SCR plant needs to be replaced periodically.

The operation of the desulphurisation system reduces the electrical net efficiency by 0.38 percentage points, the cooling tower by 0.33 percentage points compared to a natural draught cooling tower.

Operational data

In 1999 some 1,100 GWh of net electricity and 286 GWh of heat for district heating were produced. The number of equivalent full load hours amounted to 3,860. Table 2-22 shows the atmospheric emissions of the coal-fired boiler and the gas turbine in 1999.

Table 2-22: Emission limit values and measured emission levels in 1999

	Coal fired boiler			Gas turbine	
	ELV (*1/2-hour mean value at 6 % O_2)	Measured emission level	Specific emissions [g/MWh_{el}]	ELV (*1/2-hour mean value at 15 % O_2)	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 compund operation)	
Flue gas volume flow rate [m^3/h]		$900,000^{1)}$			550,000
Dust [mg/Nm^3]	20^{*}	$5^{1)}$	13.47		
Opacity [Ringelmann Chart]				2^{*}	$0.2^{3)}$
SO_2 [mg/Nm^3]	100^{*}	$20^{1)}$	56.89		
NO_x [mg/Nm^3]	130^{*}	$90^{1)}$	254.49	100^{*}	$70^{3)}$
CO [mg/Nm^3]	100^{*}	$16^{1)}$	44.91	100^{*}	$20^{3)}$
HCl [mg/Nm^3]	20	$2^{2)}$	5.99		
HF [mg/Nm^3]	2	$0.2^{2)}$	0.60		

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

Some 360,000 tons of hard coal from different parts of the world were fired in 1999. Additionally 10^6 Nm^3 of natural gas and 1,800 tons of light fuel oil were fired. The consumption of the most important auxiliary supplies are shown in Table 2-23.

Table 2-23: Consumption of important auxiliary supplies in 1999

Auxiliary material	Application	Consumption [t/a]	Specific consumption [g/MWh$_{el}$]
2.1.6.1 Lime	Desulphurisation	470	430
Grinded Limestone		9,000	8,200
NaOH	Wastewater treatment	120	110
HCl		230	210
H_2SO_4		50	46
FeCl		520	476
NH_3	SCR	890	815

The water consumption of the cooling tower amounts to 540 m^3/h. A share of 37 % of this flow is released to the adjacent river. The rest is being evaporated. This effluent contained impurities such as COD (chemical oxygen demand) (20 mg/l), phosphor (0.2 mg/l) and nitrogen (23 mg/l). The number in the brackets are mean values for 1999. The wastewater from the desulphurisation plant is being treated in a separate installation with flocculation agents and subsequent sedimentation. 50 % of this water is then used as cooling water. The remaining 50 % is discharged to the river. The concentration of impurities in this wastewater is shown in Table 2-24.

Table 2-24: Concentrations of impurities in the wastewater of the desulphurisation plant after treatment (measurements in 1998/1999; mean values)

	Limit values [mg/l]	Mean value from 2 to 3 measurements [mg/l]	Specific load [g/MWh$_{el}$]
Chlorine		40,000	1.20E+03
COD	150	<150	4.49E+00
Zink	1	<1	2.99E-02
Chromium	0.5	<0.5	1.50E-02
Cadmium	0.05	<0.05	1.50E-03
Copper	0.5	<0.5	1.50E-02
Lead	0.1	<0.1	2.99E-03
Nickel	0.5	<0.5	1.50E-02
filterable matter	30	17	5.09E-01
Sulphate	2,000	2,542	7.61E+01
Sulphite	20	2	5.99E-02
Fluoride	30	8	2.40E-01
Mercury	0.05	0.007	2.10E-04
Sulphide	0.2	0.07	2.10E-03

Table 2-25 shows the quantities of residues produced in 1999.

Table 2-25: Residues generated in 1999

	Ash (standardised quality)	Boiler sand	Lime sludge from cooling tower makeup water treatment	FGD gypsum, fine grained	FGD gypsum, briquette
Quantity [t/a]	53,000	5,500	4,000	14,000	13,000
Specific Quantity [kg/MWh$_{el}$]	48.2	5	3.6	12.7	11.8
Utilisation / Disposal	Cement and concrete industry	Building material industry	Cement industry, fertiliser	Gypsum and cement industry	Gypsum and cement industry

The legal requirements for sound control are adapted to the residential site which is about 400 m away from the plant. These levels can be reached with the help of exhaust silencers, acoustic screens around the cooling tower and panelling of the facade.

Economic Data

The total investment amounted to 615 Mio EUR at the time of commissioning. That relates to a specific investment of 1549 EUR/kW$_{el}$.

Driving force for implementation

The reason to build the plant firstly resulted from the need to replace three old coal-fired boilers at the end of their lifetime. These three boilers from the 50s and 60s offered a high flexibility in operation. One main reason for the realisation of the compound technique was the possibility to keep this high grade of flexibility. High efficiencies for part load operation and short times to get into and out of operation are 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 residents from shades. The relative low emission limit values for atmospheric emissions are imposed because of the natural surrounding of the site. Situated in narrow valley the air quality limits can quite easily be exceeded. Consequently the emission limit values are comparatively stringent.

2.1.7 Example: Pulverised hard coal firing with wet bottom boiler and secondary emission control

Description

The presented power plant has a rated thermal power input of 1,892 MW, an electrical gross capacity of 752 MW_{el} and an electrical net capacity of 702 MW_{el}. The electrical gross / net efficiency amounts to 41.3 / 38.6 %.

The forced circulation boiler with a wet ash removal is equipped with a single reheating system. The double ash fusion furnace is equipped with 32 coal burners at the ceiling, which are supplied with pulverised coal from 8 coal mills.

The firing is especially adapted to the anthracitic coal, which is extracted in the nearby coal mine. This coal is characterised by a low content of volatiles (5 – 7 %) which results in a very bad flammability. Since 1997, the auxiliary firing uses orimulsion instead of heavy fuel oil.

The ESP is situated downstream the boiler. The fly ash has a high content of combustible matter and is thus recirculated to the boiler. For this reason arsenic enriches in the fly ash and in the raw gas.

NO_x control

The bad flammability of the coal prevents the utilisation of fuel- and air-staging or flue gas recirculation as primary NO_x-control. These measures would not allow for a stable firing. Already without these measures, an extensive use of the auxiliary firing is necessary to hold up the coal firing.

The high combustion temperatures of 1,600 – 1,700 °C result in high NO_x-contents in the raw gas of about 2,000 mg/Nm^3. For this reason, a 2-staged SCR plant was commissioned in 1988 which was extended by a third stage in 1994. The SCR-plant was realised in a low-dust configuration. The more efficient high-dust configuration without preheating of the flue gas was not realised as high erosion rates and fast degradation of the catalyst material due to high arsenic concentrations in the fly ash were predicted. Under these conditions the catalyst material would have had to be changed every 1,000 hours.

The SCR-plant needs a flue gas temperature of 270 - 330 °C which is realised with a regenerative preheater. This needs about 25 MW_{th}. The clean gas shows less than 200 mg/Nm^3 NO_x downstream the SCR without a measurable ammonia slip. Downstream the regenerative preheater the clean gas is conducted to the stack with a temperature of 145 °C.

Desulphurisation

The three wet FGD-plants (separation efficiency of 92 - 95 %) are designed for the use of hydrated calcium lime. Since 1989 grinded limestone is used for economical reasons. The produced gypsum has a water content of 10 % and is used in the cement industry.

Main environmental benefits

Secondary techniques to reduce emissions as well as the electrical net efficiency and the wastewater treatment are state of the art in Germany. All residues are either utilised (slag tap granulate, gypsum) or fed into the boiler (fly ash, sludges from water and wastewater treatment).

Applicability

The techniques to reduce atmospheric emissions can be applied in any hard coal fired power plant. The design of the plant is optimised for the specific anthracitic coal and is thus not reasonable for coals with other characteristics.

Cross-media aspects

The wet FGD produces wastewater and gypsum. The slag tap granulate is completely used in the building material industry. The operation of the SCR and the wet FGD reduce the electrical efficiency of the plant.

Operational Data

In the year 1999 the plant was in operation for 6120 hours and produced 4500 GWh_{el} of gross electricity.

The following atmospheric emissions were measured.

Table 2-26: Emission limit values and measured atmospheric emissions in 1999

	ELV at 5 % O_2	Measured emission levels	Specific emissions [g/MWh_{el}]	Measurement
O_2-Content [%]		3 - 4		continuous
Operational state		full load		
Flue gas volume flow rate [m^3/h]		2,400,000		
Dust [mg/Nm^3]	50	5 - 10	17.3 - 34.6	individual
SO_2 [mg/Nm^3]	400	185	639	continuous
Sulphur emission rate [%]	15	11.4	39	continuous
NO_x [mg/Nm^3]	200	200	691	continuous
CO [mg/Nm^3]	250	27	93	continuous
HCl [mg/Nm^3]	100	3 - 11	10 - 31.1	individual
HF [mg/Nm^3]	15	3 - 10	10 - 34.6	individual
NH_3 [mg/Nm^3]		< 0.5	< 2	

1,411 kilotons of anthracitic coal were fired. The characteristics of the coal is shown in Table 2-27.

Table 2-27: Average characteristics of the fired anthracitic coal

Heating value [MJ/kg]	27.7 – 29.3
Water content [%]	8 - 10
Sulphur content [%]	0.8 - 1
Ash content [%]	10 – 13
Volatiles content [%]	5 – 7
Grindability, Hardgrove [°H]	30 - 40
Cl content [%]	0.15

The wet FGD needs 6 t/h of limestone, the SCR consumes about 2 t/h of ammonia.

The total consumption of water amounts to 1,400 m^3/h. The total wastewater flow rate of the power plant mounts up to 270 m^3/h. The rain water is treated together with the effluent of the cooling system (flocculation, precipitation, sedimentation) and is dumped to the preclarifier (630,000 m^3 in 1999) with mean concentrations of impurities as shown in Table 2-28.

The wastewater from the desulphurisation plant (50 m^3/h, 200,000 m^3 in 1999) is being treated in a separate installation with flocculation agents and subsequent sedimentation and neutralisation. Table 2-29 shows the quality of this wastewater flow.

Some 29,000 m^3 in 1999 originate from the condensate treatment and other sources of the steam generation. After neutralisation this wastewater is discharged to the preclarifier with mean concentrations of impurities as shown in Table 2-30.

Table 2-28: Concentrations of impurities in the rain water and cooling water after treatment in 1999

	AOX	COD	P_{total}	N_{total}	Zn	Cr	Cd	Cu	Pb	Ni
Mean concentration [mg/l]	0.068	40	0.1	25	< 0.02	0.009	0.0002	0.05	< 0.002	0.009
Specific load [g/MWh$_{el}$	0.01	6	0.015	3.75	0.003	0.0014	0.00003	0.0075	0.0003	0.0014
Limit values [mg/l]	0.15-1	30-80	1.5-5	10	1	0.5	0.05	0.5	0.1	0.5

Table 2-29: Concentrations of impurities in the wastewater of the desulphurisation plant after treatment in 1999 (mean values)

	filterable matter	sulphate	sulphite	fluoride	mercury
mean concentration [mg/l]	9	1,200	12	10	0.002
specific load [g/MWh$_{el}$]	0.42	0.06	0.57	0.48	$1*10^{-4}$
limit values [mg/l]	30	2000	20	30	0.05

Table 2-30: Concentration of impurities in the wastewater from condensate treatment and other sources of the steam generation process

	AOX	P_{total}	N_{total}	Zn	Cr	Cd	Cu	Pb	Ni
mean concentration [mg/l]	0.23	0.02	24	< 0.075	0.033	<0.0001	0.033	< 0.002	0.08
specific load [g/MWh_{el}	1.6	0.14	166	< 0.52	0.23	$< 7 \cdot 10^{-4}$	0.23	< 0.014	0.55
limit values [mg/l]	0.15-1	1.5-5	10	1	0.5	0.05	0.5	0.1	0.5

The main residues are slag tap granulate (25 t/h, 36 g/kWh_{el}) and gypsum (12 t/h, 15 g/kWh_{el}).The legal requirements for sound control are adapted to the residential site which is about 500 m away from the plant. These levels can be reached with the help of exhaust silencers, acoustic screens around the cooling tower and overhead noise barriers.

Economic Data

There is no data available.

Driving force for implementation

Secondary emission control is state of the art and was implemented due to national legislation. The reason for the missing primary NO_x-control lies in the special characteristics of the fired anthracitic coal.

2.1.8 Example: Hard coal slag tap firing with SCR and spray dry absorption process (SDA)

Description

This combined heat and power plant operates at a rated thermal input of 183 MW_{th}, a gross electrical power of 49,3 MW_{el} (net power about 46 MW_{el}) and can deliver a maximum of 110 MW_{th} of long-distance heating via condensers. Therefore, the maximum of the gross electrical efficiency is 27 % (about 25.3 % netto), the maximum of the gross overall energy efficiency is 87%. The steam turbine is a backpressure turbine which means that the maximum of the electrical power is reached by maximal tapping of heat for long- distance heating.

This plant has been started up in 1984 and was retrofitted in 1986 with a desulphurisation (spray dry absorber) and in 1988 with a denitrification (SCR) of the flue gas.

The driving force for using the slag tap firing was the fact that the depositing of the granulated boiler slag would be less expensive than the disposal of fly ashes out of dry bottom firing. In order to fulfil the requirement of 30 % part load at pure firing of hard coal, a double- u- slag tap furnace was implemented, of which one part can be turned off for operating at part load. While operating with just one part of the furnace, the flue gas flow has to be controlled to avoid the drop out of fly ash in the second chamber. This is realized by a divider installed in the middle between the slag grids and the combustion chambers. In order to minimize the NO_x- emissions, the burners are installed at the ceiling of the combustion chambers and are swirl spraying burners and with secondary and tertiary air injection.

After leaving the boiler, the flue gas passes the following plants in the given order: air preheater, primary dust removal (removal of fly ash), spray dry absorber, bag filter, SCR-reactor, gas-gas- heat exchanger, stack.

Main environmental benefits

The primary and secondary measurements result in low atmospheric emissions. The relatively high overall energy efficiency are reached by using a combined heat and power plant.

Cross media aspects

The residues accruing from the flue gas cleaning are:

- Electrostatic precipitator: fly ash is returned into the boiler and becomes granulated boiler slag (ca. 2.3 t/TJ_{fuel})
- Spray dry absorber (SDA): SDA- product (ca. 2.71 t/TJ_{fuel}), is deposited

In addition to that, the energetic demand of the flue gas cleaning plants reduces the energy efficiency of the whole plant (about 0.5 MW_{el} of energy demand).

Operational data

In 1999, the gross overall energy efficiency reached 81%. With 8,518 operating hours the plant covered the base load. Based on the total energy input the plant operated for 5,174 equivalent full load hours.

In 1999, the following data for atmospheric emissions were measured:

Table 2-31: Limit values and measured data for emissions in 1999

	Limit values (1/2-hour-values at 6% O_2)	Measurement at 6% O_2	Specific emissions [kg/TJ_{fuel}]
O_2-content in the flue gas [%]	5	5 - 6	
Flue gas volume flow [m^3/h]		240,000[1]	
Dust [mg/Nm^3]	65	14.7[1]	5.36
Sulphur emission rate [%]	10		
SO_2 [mg/Nm^3]	250	75.5[1]	27.5
NO_x [mg/Nm^3]	400	323[1]	118
CO [mg/Nm^3]	175	5.7[1]	2.1
HCl [mg/Nm^3]	20	0.7[2]	0.26
HF [mg/Nm^3]	3	0.05[2]	0.018

[1] continuous measurements, annual mean value

[2] average of single values

In 1999, 146.14 kt of hard coal were burned. Additionally 403 t of heavy fuel oil was utilized. Because the boiler is implemented especially for the use of hard coal coming from the Ruhr district, only this sort of coal was used.
3,277 t of lime for the SDA (equal to 0.87 t/TJ_{fuel}) and 491 t of ammonia (equal to 0.13 t/TJ_{fuel}) for the SCR- plant were consumed.
The only source of waste water was the water treatment plant. 75% of the eluate coming from this plant is used in the desulphurisation process. The rest of it (about 0.25 m^3/h) is neutralized with the concentration of substances given in Table 2-32 and dumped into the preclarifier.

Table 2-32: Contents of substances in the neutralized waste water flow

	average of two measurements in 1999 [mg/l]
Zn	0.1
Cr	< 0.001
Cd	< 0.001
Cu	0.03
Pb	0.03
Ni	0.07
sulfate	250
hydrocarbons	< 2
volatile chlorine hydrocarbons	< 0.001

Residues are accruing in quantities shown in Table 2-33.

Table 2-33: Quantities of waste in 1999

Type of waste	granulated boiler slag	SDA-by-product	filter and absorbing materials	oils	polystyrene	various materials	residues able to be composted	paper / paperboard
Quantity	8,686 t/a	101,95 t/a	6.6 m^3/a	1.9 m^3/a	10 m^3/a	58 t/a	15 t/a	204 m^3/a

The legal requirements for noise prevention for the residential area which is situated about 100-200 m from the plant are fulfilled by the use of sound absorption installations in the ventilation openings.

Economic data

There is no data available.

Driving force for implementation

Driving force for the implementation of the denitrification and the desulphurisation plant for the flue gas were the legal restraints concerning the reduction of atmospheric emissions.

2.1.9 Example: Pulverised lignite-fired dry bottom boiler – primary NOx control, secondary desulphurisation and high efficiency

Description

The presented plant is a condensing steam plant with bleeding and consists of two identical units (maximum of rated thermal input = 2 x 2400 MW, 2 x 865 $MW_{el,net}$, 2 x 933 $MW_{el,brutto}$ and up to 2 x 115 MWth energy off-take for district heating and processing steam). The lignite is extracted from the nearby opencast mine. It is crushed in wet coal mills with deflecting air separator and is then fed into the forced-circulation boiler with tangential firing. The flue gas is then cleaned and emitted to the atmosphere from the natural draught cooling towers. The boilers produce steam at supercritical parameters of 285 bar and 554 °C and 583 °C/ 51.3 bar after reheating. The pressure in the condenser can be lowered to 0.038 bar.

Measures to optimise efficiency

The electrical net efficiency at the design point is 42.3 %, the overall energy efficiency can reach 46 %. These values were achieved due to the following measures:

- supercritical steam parameters were realised with the help of new materials (Austenite for the reheater surfaces; 9-%-Cr-steels (P91, T91), PFA or Ni-alloys for the heat displacement system)
- Optimised turbines (efficient blading, new materials)
- Low own consumption (efficient wet FGD, rotary speed controlled ventilator for fresh air, forced draught fan)
- Optimised preheater
- Use of flue gas heat
- No reheating of flue gas after FGD necessary as it is emitted via the cooling towers

The primary NO_x control comprises air staging without circulating the cold gas. The burners at the first two levels work under stoichiometrical conditions. Above these there is the afterburner were the combustion is realised with air number <1 followed by three levels were combustion air is injected and allows for air numbers of 0.92, 1.00 and 1.15 respectively.

The desulphurisation is performed with two wet FGD systems for every unit. They are made of high-grade steel and reach removal efficiencies > 98%. Because of damages at the rubber coating, the following design was chosen for the wet scrubbers:

- lining of the absorbers with nickel alloy – here Alloy 59
- direct discharge of the flue gas into the cooling towers without bypass- connections
- use of GRP for the clean gas tubes and pipes for suspension

For technical reasons, both limestone and quick lime can be used. Because of its lower costs, the latter is used here.

Dedusting is realised with 2 ESP installations for every unit.

Main environmental benefits

In spite of the energy consuming FGD unit a comparatively high net efficiency could be reached. The emission limit value for NO_x can be met safely solely with primary measures. The concentrations of SO_2, CO and dust in the flue gas are only 20 – 35 % of the respective emission limit values. All wastewaters are either treated or reused internally.

Applicability

The described techniques are optimised for the installation in a new pulverised lignite fired plant. The application in the case of retrofit depends on local conditions.

The ESP and the wet FGD are standard measures for emission control at lignite-fired power plants. Primary measures to reduce emissions of NO_x 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. The increase of the steam parameters is in most cases not possible for existing plants.

Cross media aspects

The flue gas cleaning produces fly ash (electrostatics precipitator), wastewater (wet FGD) and gypsum (wet FGD). The operation of the flue gas cleaning systems reduces the electrical net efficiency of the plant.

Operational Data

As this plant has been started up only recently, there are no reliably operational data available by now. Presumably, about 10,000 $GWh_{el,netto}$ (12.800 $GWh_{el,brutto}$) will be produced per year. With a number of 7,000 full load hours the plant is supposed to cover the base load. Shortly after starting continuous operation, the following atmospheric emissions were measured:

Table 2-34: Emission limit values and measured atmospheric emissions in 2000

	Monitoring	ELV at 6 % O_2	Annual mean values at 6 % O_2		Specific emissions [$g/MWh_{el,net}$]
			unit A	unit B	both units
O_2-Content [%]	continuous		0.035	0.038	
Flue gas volume flow rate [m^3/h]	continuous		2,876,000	2,996,000	
Dust [mg/Nm^3]	continuous	20	$13.7^{1)}/1.7^{2)}$	$15.7^{1)}/1.7^{2)}$	0.38
SO_2 [mg/Nm^3]	continuous	400	291.4	297.4	112
Sulphur emssion rate [%]		5	3.0	2.9	
NO_x [mg/Nm^3]	continuous	200	120.9	124.7	43
CO [mg/Nm^3]	continuous	250	7.7	26.2	4.9
HCl [mg/Nm^3]	individual	15			
HF [mg/Nm^3]	individual	5			

1) upstream FGD

2) downstream FGD

Concerning the design, about 10,300 kt of raw lignite (equal 0.73 kg/kWh_{el}) of the following characteristics are used per year:

Table 2-35: Characteristics of the fired raw lignite

	Mean values
H_u [MJ/t]	10,945
Water content [%]	51.5
Sulphur content [%]	1.91
Ash content [%]	6.3

Furthermore, about 10,100 t/a of light fuel oil are used.

The estimated consumption of the most important auxiliary supplies are given in Table 2-36.

Table 2-36: Estimated consumption of important auxiliary supplies

Auxiliary material	Quick lime	NaOH	HCl	NH_4OH
Application	wet FGD	waste water treatment		
Consumption [t/a]	248,000	1,470	2,180	31.8
Specific consumption [g/MWh_{el}]	24,800	0.11	0.17	0.002

Most of the fresh water demanded is used for the cooling towers, it amounts to 3,900 m^3/h. The total wastewater flow amounts to 1,540 m^3/h. One part of this flow (340 m^3/h) results from condensate treatment, steam production and desalination plant. This part is treated by neutralisation, flocculation and sedimentation. The concentrations of impurities after treatment are given in Table 2-37.

Table 2-37: Concentrations of impurities in the wastewater resulting from the condensate treatment, steam production and desalination plant

	AOX	COD	P_{total}	N_{total}	Zn	Cr	Cd	Cu	Pb	Ni
Range of concentrations [mg/l]	0.02 – 0.1	30 - 75	0.2 - 1	10 - 30	< 0.01	< 0.01	< 0.03	< 0.01	< 0.01	< 0.01
Mean values [mg/l]	0.05	50	0.3	20						
Specific load [g/MWh$_{el}$]	0.01	9.4	0.06	3.8						
Limit values [mg/l]	0.15-1	30-80	1.5-5	10	1	0.5	0.05	0.5	0.1	0.5

Table 2-38 shows the quantities of residues produced in the first half of 2000.

Table 2-38: Residues generated in the first half of 2000

Type of waste	Bottom ash	Fly ash	FGD gypsum
Classification in Germany (Krw-/AbfG)	„No need to be monitored“		
Quantity [t/a]	19,000	142,000	377,000
Specific Quantity [kg/MWh$_{el}$]	0.004	0.03	0.079
Utilisation / Disposal	Landscape architecture (reinforcement of embankments)	Reinforcement of embankments for gypsum depot and landscape architecture, Cement and Building material industry	Gypsum industry; Partly stored for long-term use in empty lignite mine

The legal emission levels for sound are adapted to the residential site which is about 700 m away from the plant. These levels can be reached with the help of exhaust silencers in the flue gas channels, panelling of the facade and acoustic screens around the cooling tower. By these measures the effective emission was reduced to a sound pressure level of 113 dB(A).

Economic Data

The total investment amounted to $2.45 \cdot 10^9$ € (2000). That relates to a specific investment of 1443 €/kW$_{el}$. The overhead costs amount to approximately 39 €/kW*a (estimated).

Driving force for implementation

The ESP, the wet FGD and primary NO_x control were installed to comply with the emission limit values. The primary measures for NO_x control do not only apply to meet the ELV, but they increase the efficiency as well and thus improve the economical performance of the plant. The optimisation of the efficiency was primarily realised for economical reasons.

2.1.10 Example: Pulverised lignite-fired dry bottom boiler – primary NOx control, secondary desulphurisation and high efficiency

Description

The presented plant is a condensing steam plant with bleeding and consists of two identical units which were commissioned in 1995 and 1996 respectively. The maximal rated thermal input is 2* 1,243 MW_{th} and the gross power of the two three- phase turbine- generators of 50 Hz is 2*425 MW_{el}. In addition to this, a turbine generator for railway with 110 MW_{el} is installed. In total this results in 900 MW_{el} of net power. Furthermore, up to 90 t/h of process steam of middle pressure (equal 74 MW_{th}) and up to 110 t/h process steam of low pressure (equal 83.7 MW_{th}) can be tapped. A nearby factory for chemicals ensures a continuous demand of power and process steam. The lignite is extracted from a opencast mine about 40 km from the plant. It is crushed in 8 coal mills per unit and is then fed into the forced-circulation boiler with tangential firing. The flue gas is then cleaned and emitted to the atmosphere via a stack. The boiler produces main steam with supercritical parameters at 265 bar/ 544 °C and 560 °C after reheating.

Measures to optimise efficiency

The electrical net efficiency at the design point is 40 % was achieved due to the following measures:

- supercritical steam parameters were realised with the help of new materials
- Optimised turbines (efficient blading, new materials)
- Low own consumption
- Optimised connections of the water- steam- circuit (for example preheating of the condensate and the feed water by seven steps)

The main characteristic of this plant apart from its high efficiency is its high flexibility in operation. Which ensures at the same time the basic load for the factory for chemicals and the middle and peak load for the railway power and power for public demands. For this purpose the boiler had to be designed for low- load operation at 40 % of the unit load and for rates of load change of 6 % per minute. Therefore the steam turbines were constructed with housings consisting of two shells, which allows to have lower thickness and therefore higher rates of load change.

The primary NO_x control comprises the use of a low-NO_x burner and air staging. The desulphurisation is performed with one wet FGD system for each unit. They are made of high-grade steel and reach removal efficiencies of 94.6 %. Dedusting is realised with ESP installations.

Main environmental benefits

In spite of the energy consuming FGD unit a comparatively high net efficiency could be reached. The emission limit value for NO_x can be met safely solely with primary measures.

Applicability

The described techniques are optimised for the installation in a new pulverised lignite fired plant. The application in the case of retrofit depends on local conditions.

The ESP and the wet FGD are standard measures for emission control at lignite-fired power plants. Primary measures to reduce emissions of NO_x 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. The increase of the steam parameters is in most cases not possible for existing plants.

Cross media aspects

The flue gas cleaning produces fly ash (electrostatics precipitator), wastewater (wet FGD) and gypsum (wet FGD). The operation of the flue gas cleaning systems reduces the electrical net efficiency of the plant.

Operational Data

In 1999 the plant produced 3,405 GWh_{el} of net electricity (3,778 GWh_{el} gross). The net electrical efficiency therefore reached 35.7 %. Turbine A had 4,331 operational hours, turbine B 7,423 hours. The turbine for railway power reached 7,321 operational hours.

In 1999, the following atmospheric emissions were measured:

Table 2-39: Emission limit values and measured atmospheric emissions in 1999

	Monitoring	ELV at 6 % O_2	Daily mean values at 6 % O_2	Specific emissions [kg/TJ fuel input]
O_2-Content [%]	continuous		6	
Flue gas volume flow rate [m^3/h]	continuous		2 x 1,800,000	
Dust [mg/Nm^3]	continuous	50	13.5	5.4
SO_2 [mg/Nm^3]	continuous	400	211	84.9
Sulphur emission rate [%]	continuous	15	2.9	
NO_x [mg/Nm^3]	continuous	200	149	59.7
CO [mg/Nm^3]	continuous	250	4.4	1.8

3,166 kilotons of lignite (equivalent to 0.83 kg/kWh_{el}) with a calorific value of 10.86 MJ/kg and 4,721 tons of light fuel oil were fired.

For the FGD plant, 163,876 tons of limestone were used, equal to 0.043 kg/kWh$_{el}$. About 260 kilotons of gypsum were produced in 1999.

Table 2-40 shows the different sources of waste water within the power plant, the amounts produced in 1999 and the treatment.

Table 2-40: Quantities of waste water produced in 1999

	Output of concentrate of the reverse osmosis process	Waste water of the regeneration of the ion exchangers	Cooling tower	Waste water of the FGD plant
Quantities in 1999 [m^3]	480,000	28,000	1,710,000	82,000
Treatment		neutralisation		precipitation by $Ca(OH)_2$ and organo-sulfide; flocculation by $FeClSO_4$

The concentrations of impurities for the FGD waste water are given in Table 2-41, those for the waste water accruing at the cooling tower and the output of the concentrates of the reverse osmosis process are given in Table 2-42.

Table 2-41: Concentrations of impurities for the waste water for the following sources: desalination of the cooling tower, output of the concentrates of the reverse osmosis process

	AOX	COD	P_{total}	N_{total}
Concentration (arithm. mean value of 4/99 – 4/00 out of 12 values) [mg/l]	0.08	27.85	0.32	22.88
Specific load [g/MWh$_{el}$]	47.2	15,700	181	12,900
Limit values [mg/l]	0.15-1	30-80	1.5-5	10

Table 2-42: Concentrations of impurities in the waste water of the FGD waste water treatment output

	Limit values [mg/l]	Concentration (arithm. mean value of 4/99 – 4/00 out of 12 values) [mg/l]	Specific load [g/MWh$_{el}$]
filterable material	30	7	0.17
sulphate	2000	1,300	31.3
sulphite	20	0.5	0.012
fluoride	30	1.5	0.036
mercury	0.05	0.001	2.408E-05

The requested emission limits for sound are adapted to the residential site which is about 600 to 1,800 m away from the plant. These levels can be reached with the help of exhaust silencers in the flue gas channels and for the roof, panelling of the facade, double sliding doors, the use of gas concrete and acoustic screens around the cooling tower. By these measures the effective emission was reduced to a sound pressure level of between 31.3 and 38.9 dB(A) at the measurement points, which are situated 620 to 1,800 m from the plant.

Economic Data

The total investment amounted to 1280 Mio € (1996). That relates to a specific investment of 1422 €/kW$_{el,net}$. The overhead costs amount to approximately 41 €/kW·a (estimated).

Driving force for implementation

The ESP, the wet FGD and primary NO_x control were installed to comply with the emission limit values. The primary measures for NO_x control do not only apply to meet the ELV, but they increase the efficiency as well and thus improve the economical performance of the plant. The optimisation of the efficiency was primarily realised for economical reasons.

2.1.11 Example: Pulverised lignite-fired dry bottom boiler – primary NO_x control, secondary desulphurisation and high efficiency

Description

The presented plant consists of two identical units and has a net electricity output of 2 x 750 MW$_{el}$ and up to 2 x 257 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 deflecting air separator. The flue gas is then cleaned and emitted to the atmosphere from the 2 natural draught cooling towers. The boilers produce steam at 268 bar and 547 °C and 565 °C after reheating. The pressure in the condenser can be lowered to 0.036 bar.

Measures to optimise efficiency

The electrical net efficiency at the design point is 40.1 %, the overall energy efficiency can reach 55 %. These values were achieved due to the following measures:

- supercritical steam parameters were realised with the help of new materials (Austenite for the reheater surfaces; 9-%-Cr-steels (P91, T91), PFA or Ni-alloys for the heat displacement system)
- Optimised turbines (efficient blading, new materials)
- Low own consumption (efficient wet FGD, forced draught fan)
- Optimised preheater
- Use of flue gas heat
- No reheating of flue gas after FGD necessary as it is emitted via the cooling towers

The primary NO_x control comprises fuel and air staging. The burners at the first two levels work under stoichiometrical conditions. Above these there is the afterburner were the combustion is realised with air number <1 followed by three levels were combustion air is injected and allows for air numbers of 1, 1.12 and 1.15 respectively.

The desulphurisation is performed with two wet FGD systems for every unit. They are made of high-grade steel and reach removal efficiencies > 98%.

Dedusting is realised with 2 ESP installations for every unit.

Main environmental benefits

In spite of the energy consuming FGD unit a comparatively high net efficiency could be reached. The emission limit value for NO_x can be met safely solely with primary measures. The concentrations of SO_2, CO and dust in the flue gas are only 20 – 35 % of the respective emission limit values. All wastewaters are either treated or reused internally.

Applicability

The described techniques are optimised for the installation in a new pulverised lignite fired plant. The application in the case of retrofit depends on local conditions.

The ESP and the wet FGD are standard measures for emission control at lignite-fired power plants. Primary measures to reduce emissions of NO_x 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. The increase of the steam parameters is in most cases not possible for existing plants.

Cross media aspects

The flue gas cleaning produces fly ash (electrostatics precipitator), wastewater (wet FGD) and gypsum (wet FGD). The operation of the flue gas cleaning systems reduces the electrical net efficiency of the plant.

Operational Data

In 1999 the plant reached 7,454 equivalent full load hours and produced 11,516 GWh_{el} of net electricity (12,207 GWh_{el} gross), 480 GWh of district heat and 1,002 GWh of process heat resulting in an overall energy efficiency of 44.2 %.

The following atmospheric emissions were measured.

Table 2-43: Emission limit values and measured atmospheric emissions in 1999

	Monitoring	ELV at 6 % O_2	Annual mean values at 6 % O_2		Specific emissions [$g/MWh_{el,net}$]	
			Unit 1	Unit 2	Unit 1	Unit 2
O_2-Content [%]	continuous		3.5	3.8		
Flue gas volume flow rate [m^3/h]	continuous		2.4E6	2.4E6		
Dust [mg/Nm^3]	continuous	50	1.7	2.6	3.6	4.2
SO_2 [mg/Nm^3]	continuous	400	66.0	69.8	124	129
Sulphur emssion rate [%]	continuous	5	1.7	1.8		
NO_x [mg/Nm^3]	continuous	200	144.9	141.3	274	263
CO [mg/Nm^3]	continuous	250	56.6	56.7	114	109
HCl [mg/Nm^3]	individual	7.5	0.4[1)]	0.4[1)]	0.7	0.7
HF [mg/Nm^3]	individual	2.5	0.1[1)]	0.1[1)]	0.14	0.14

[1)] mean value of individual measurements

12,068.4 kilotons of lignite (equivalent to 0.96 kg/kWh_{el}) and 4,452 tons of light fuel oil were fired. The characteristics of the fired lignite is shown in Table 2-44.

Table 2-44: Characteristics of the fired lignite

	Mean values for the reference year	Variation limits for lignite from the nearby mine
H_u [MJ/t]	8,802	7,600 – 9,000
Water content [%]	55.4	48 – 56
Sulphur content [%]	0.73	0.5 – 1.4
Ash content [%]	5.2	< 15.2

Since the year 2000 the plant has the admission to fire mixed residues (e.g. residues from tar dumps). The share of this fuel can reach up to 5 % of the total fuel mass and 9.2 % of the total thermal power input (about 600,00 tons per year). There are no emission data available yet for these fuels.

The consumption of the most important auxiliary supplies are shown in Table 2-45.

Table 2-45: Consumption of important auxiliary supplies in 1999

Auxiliary material	Limestone	NaOH	HCl	NH_4OH
Application	Wet FGD	Water treatment		
Consumption [t/a]	239,100	2,139	3,183	12
Specific consumption [g/MWh_{el}]	19,100	171	254	1

The water demand of the whole plant at full load amounts to 4,000 m^3/h. The cooling towers evaporate about 3,400 m^3/h. The total wastewater flow amounts to 1,141 m^3/h. A part of this flow (217 m^3/h) results from condensate treatment, steam production and house sewage and is treated in the sewage plant of a nearby factory. Another part of the wastewater (904 m^3/h) results from the cooling system, from neutralised wastewaters of the full water softening and from a sedimentation basin treating wastewaters from ash shipping. The annual mean values for the concentrations of impurities in this wastewater are displayed in Table 2-46.

Table 2-46: Concentrations of impurities in the wastewater resulting from the cooling system, the full water softening and the ash loading in 1999; mean values, 904 m^3/h)

	AOX	COD	P_{total}	N_{total}	Zn	Cr	Cd	Cu	Pb	Ni
Concentration [mg/l]	0.03	19	0.15	2.1	< 0.01	< 0.01	< 0.03	< 0.01	0	< 0.01
Specific load [g/MWh_{el}]	0.03	14.2	0.11	1.57					0.003	
Limit values [mg/l]	0.15-1	30-80	1,5-5	10	1	0.5	0.05	0.5	0.1	0.5

Table 2-47 shows the quantities of residues produced in 1999.

Table 2-47: Residues generated in 1999

	Bottom ash	Fly ash	FGD gypsum
Classification in Germany (Krw-/AbfG)	„No need to be monitored“		
Quantity [t/a]	22,500	540,496	422,500
Specific Quantity [kg/MWh_{el}]	0.002	0.043	0.034
Utilisation / Disposal	Cement industry, landscape architecture (reinforcement of embankments)	Reinforcement of embankments for gypsum depot and landscape architecture, Cement and Building material industry	Gypsum industry; Partly stored for long-term use in empty lignite mine

The legal emission levels for sound are adapted to the residential site which is about 550 m away from the plant. These levels can be reached with the help of exhaust silencers in the flue gas channels, panelling of the facade and acoustic screens around the cooling tower. By these measures the effective emission was reduced to a sound pressure level of 113 dB(A).

Economic data

The total investment amounted to 2,308 Mio EUR (1998). That relates to a specific investment of 1,538 EUR/kW$_{el}$. The overhead costs amount to approximately 40 EUR/kW·a (estimated).

Driving force for implementation

The ESP, the wet FGD and primary NO$_x$ control were installed to comply with the emission limit values. The primary measures for NO$_x$ control do not only apply to meet the ELV, but they increase the efficiency as well and thus improve the economical performance of the plant. The optimisation of the efficiency was primarily realised for economical reasons.

2.1.12 Example: Retrofitting of a pulverised lignite-fired dry bottom boiler with primary NO$_x$ control, secondary desulphurisation and improvement of efficiency

Description

The presented plant consists of six identical units and has a net electricity output of 6 x 465 MW$_{el}$, a gross output of 6 x 500 MW$_{el}$ 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 deflecting air separator. Each unit consists of two boilers and steam extraction turbine. The flue gas is then cleaned and released to the atmosphere from the natural draught cooling tower. The boilers produce steam at 176 bar and 535 °C. With reheating the steam parameters amount to 44.4 bar / 540 °C. The retrofitting of the units was performed between 1991 and 1995. Measures undertaken aimed at lowering the atmospheric emissions and increasing the efficiency.

Measures to increase efficiency

The net electrical efficiency was raised from 32.5 to 35.7 %. This was partly reached by exchanging the steam turbine's low pressure unit. The main boost for the efficiency came from the retrofitting of the boiler, which was primarily realised to reduce NO$_x$ emissions. With the help of air- and fuel-staging the flue gas volume flow rate could be reduced form 1.4 Mio. m^3/h to 1.15 Mio. 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 rehabilitation of the 9 cooling towers. The individual measures and their effects onto the efficiency are put together in Table 2-48.

Table 2-48: Effects of single measures to increase efficiency

	Initial state	Effects of the components				State after retrofitting
		Primary NO_x red.	Turbine, low-pressure unit	Cooling tower	FGD	
Efficiency, turbo-generator [%]	40.9	+ 0.09	+ 1.46	+ 0.25	0	42.7
Boiler efficiency [%]	84	+ 5.6	0	0	0	89.6
Auxiliary power [%]	5.2	0	0	0	+2	7.2
Electrical net efficiency [%]	32.5	+2.2	+1.5	+0.2	-0.7	35.7

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 must be fed into the boiler in a controlled way by air staging. To fulfil this requirement the boiler had to be sealed up to reduced the share of the uncontrolled combustion air by 65 %.
- Lowering of the air factor at the burners to l=0.85
- Implementation of an optimised fuel splitting with a scum separator
- Reduction of the burner height to increase fuel concentration
- Cold flue gas recirculation
- Post combustion
- Complete CO conversion can be ensured by two levels of burnout air injection.

Desulphurisation

Every boiler was retrofitted with a wet flue gas desulphurisation unit. The main tanks are made of high-grade steel. The concentration of SO_2 in the raw gas reaches values of up to 7,700 mg/Nm^3. There was no need to install a bypass for the FGD. The cleaned gas is conducted to the cooling towers via tubes made of glass reinforced plastic (GRP). The emission via the cooling towers allows for the abandonment of reheating of the cleaned gas.

Dust control

The existing electrostatic precipitators were retrofitted and reach separation efficiencies of above 99 %. Additional dedusting occurs in the wet FGD unit.

Main 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 4,000 – 5,000 mg/Nm^3 to < 200 mg/Nm^3. The primary measures to reduce NO_x are of special importance as they did not only halve the NO_x emissions but also increased the efficiency by 2.2 percentage points.

Applicability

The ESP and the wet FGD are standard measures for emission control at lignite-fired power plants. Primary measures to reduce emissions of NO_x 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 aspects

The flue gas cleaning produces fly ash (electrostatic precipitator), wastewater (wet FGD) and gypsum (wet FGD). The operation of the flue gas cleaning systems reduces the electrical net efficiency of the plant by 0.7 percentage points.

Operational Data

In 1999 the plant reached 7,262 full load operation hours and produced 19,931 GWh_{el} of net electricity (21,788 GWh_{el} gross) with an electrical efficiency of 33.7 %. The net electrical efficiency at the design point is 35.7 %.

The following atmospheric emissions were measured.

Table 2-49: Emission limit values and measured atmospheric emissions in 1999

	Monitoring	ELV at 6 % O_2	Annual mean values of the individual units at 6 % O_2	Annual mean values for the whole plant at 6 % O_2	Specific emissions [$g/MWh_{el,net}$]
O_2-Content [%]	continuous			5.4	
Flue gas volume flow rate [m^3/h]	continuous			865,000	
Dust [mg/Nm^3]	continuous	50 (upstream FGD)	< 20 (upstream FGD). 3 (downstream FGD)	3	0.91
SO_2 [mg/Nm^3]	continuous	400	140 - 200	170	51.51
Sulphur emission rate [%]	continuous	5	2.7 - 5	3.8	-
NO_x [mg/Nm^3]	continuous	200	164 - 188	176	53.31
CO [mg/Nm^3]	continuous	250	164 - 200	182	55.15
HCl [mg/Nm^3]	individual	30	<1 1)	1 1)	0.30
HF [mg/Nm^3]	individual	5	<1 1)	1 1)	0.30

1) mean value of individual measurements

24,693.4 kilotons of lignite (equivalent to 1.13 kg/kWh_{el}) and 7,482 t of light fuel oil were fired. The characteristics of the fired lignite is shown in Table 2-50.

Table 2-50: Characteristics of the fired lignite

	Mean values for the reference year	Variation limits for lignite from the nearby mine
H_u [MJ/t]	8,611	7,600 – 9,000
Water content [%]	55.3	48 - 56
Sulphur content [%]	0.93	0.5 – 1.4
Ash content [%]	9.3	5.5 – 15.2

The consumption of the most important auxiliary supplies are shown in Table 2-51.

Table 2-51: Consumption of important auxiliary supplies in 1999

Auxiliary material	Limestone	NaOH	HCl	NH_4OH	H_2SO_4
Application	Wet FGD	Water treatment			
Consumption [t/a]	684,000	357	487	12	1,230
Specific consumption [g/MWh$_{el}$]	31,400	16	22	0.6	56

The water demand of the whole plant at full load amounts to11,000 m^3/h. The cooling towers evaporate 5,800 m^3/h and the water discharge to the adjacent river from the cooling system amounts to 7,580 m^3/h. The total wastewater flow amounts to 1,087 m^3/h. A part of this flow (516 m^3/h) results from the cooling tower makeup water treatment, the full water softening, the steam generation and other minor sources. These wastewaters are either treated with precipitation, flocculation and sedimentation or are discharged to an external sewage treatment plant. The annual mean values for the concentrations of impurities in this wastewater are displayed in Table 2-52.

Table 2-52: Concentrations of impurities in the wastewater of the cooling tower makeup water treatment, the full water softening, the steam generation and other minor sources after treatment plant (measurements in 1999; mean values, 516 m^3/h)

	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$_{el}$]	0.06	4.12	0.01	0.36	0.01			0.06	0.005	
Limit values [mg/l]	0.15-1	30-80	1.5-5	10	1	0.5	0.05	0.5	0.1	0.5

Table 2-53 shows the quantities of residues produced in 1999.

Table 2-53: Residues generated in 1999

Abfallbezeichnung	Bottom ash	Fly ash	FGD gypsum
Classification in Germany (Krw-/AbfG)	„No need to be monitored“		
Quantity [t/a]	491,000	1,815,000	1,210,200
Specific Quantity [kg/MWh_{el}]	0.022	0.083	0.055
Utilisation / Disposal	Cement industry, landscape architecture (reinforcement of embankments)	Reinforcement of embankments for gypsum depot and landscape architecture, Cement and Building material industry	Gypsum industry; Partly stored for long-term use in empty lignite mine

The legal requirements for sound emission levels are adapted to the residential site which is about 1300 m away from the plant. These levels can be reached with the help of exhaust silencers in the flue gas channels and panelling of the facade.

Economic Data

The total investment for the retrofitting amounted to 1,759 Mio EUR (1996). That relates to a specific investment of 643 EUR/kW_{el}. Table 2-54 shows the investment for the individual measures of the retrofitting.

Table 2-54: Investments for retrofitting

Wet FGD plants	1154 Mio EUR
NO_x-Reduction	176 Mio EUR
Retrofitting of 24 ESP	12.3 Mio EUR
Sanitation of 9 cooling towers	115 Mio EUR
Retrofitting of the turbines	85 Mio EUR
Renewal of the control and instrumentation technology	267 Mio EUR

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 it could also significantly increase the efficiency and thus improve the economical performance of the plant. The optimisation of the efficiency was primarily realised for economical reasons.

2.1.13 Example: Pulverised brown coal fired boiler with retrofitted primary NO_x control and a two-stage activated coke filter (combined SO_2/NO_x abatement)

Description

Two units were erected in 1966 and 1979 with a gross capacity of 112 / 130 MW_{el} and a rated power input of 278 / 356 MW respectively. A minor part of the heat is used for district heating. The hard brown coal is transported to the site by train from a nearby opencast mine. After cleaning the flue gas is emitted to the atmosphere from two stacks with heights of 126 / 190 m respectively. For flue gas cleaning the two-stage activated coke process ("Bergbau-Forschung/Uhde-Process") is applied for both units. It allows for simultaneous reduction of NO_x and SO_2. Figure 2-6 shows a schematic flow diagram of this process.

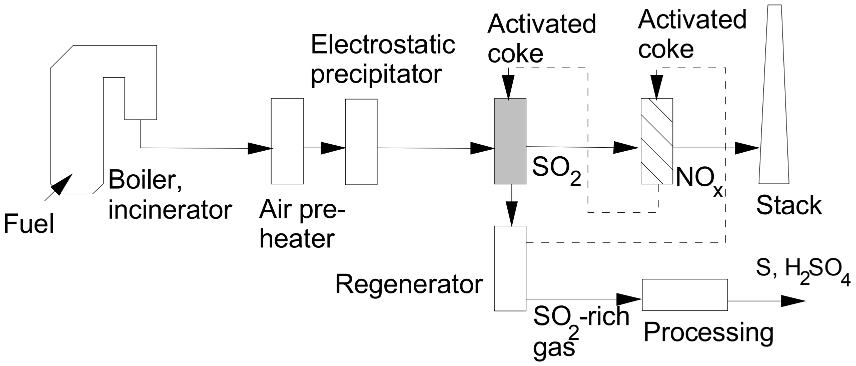

Figure 2-6: Schematic flow diagram of the two-stage activated coke process

This process reduces the SO_2 emissions by 99,9 % and the NO_x emissions by 75 %. These values can be reached with the help of highly porous activated coke, which has an active area of 450 m^2 per gram. Downstream the electrostatic precipitators the temperature of the flue gas is cooled down to 120 °C. It is subsequently fed into the first stage of the activated coke process. Here, the sulphur dioxide and other pollutants like heavy metals and organic compounds are being adsorbed at the coke. Then the flue gas is fed into the second stage together with gaseous ammonia. Here, the catalytic properties of activated coke allow for the NO_x reduction with ammonia to form nitrogen and water. The loaded coke of the fist stage is regenerated in a desorption tube were it is heated to 450 °C to expel the pollutants. The regenerated coke is cooled down and then fed back to the flue gas cleaning process. The produced gas is enriched in SO_2. Other pollutants such as halogens and heavy metals are removed from this gas before being fed into a sulphuric acid plant. The production of up to 30,000 tons of sulphuric acid per year (depending on the sulphur content) is sold to the chemical industry.

Primary measures for NO_x-reduction

Low-NO_x-burners and air-/fuel-staging were retrofitted to reduce the NO_x-concentration in the raw gas.

Main environmental benefits

The described flue gas cleaning entails extremely low concentrations of SO_2 (about 5 mg/Nm^3 compared to ELV of 400 mg/Nm^3 at 6 % O_2). At the same time the operation of the flue gas cleaning systems doesn't produce wastewater. This advantage plays an important role, as water flow rate of the adjacent river is rather small.

High removal efficiencies can also be reached for other pollutants like NO_x, halogens, heavy metals and toxic organic compounds.

The high separation efficiency is also reached for the emissions of SO_2 and SO_3 of the sulphuric acid plant as their off-gases are also lead through the adsorber.

The emission control system produces no waste waters. The waste waters of the sulphuric acid plant are nozzled into the raw gas, were they are evaporated.

Applicability

By reason of the modular construction of the activated coke process it is especially suitable for smaller power plants. The largest available installations can manage a flue gas volume flow rate of up to 1,200,000 m^3/h. In Japan, units for up to 2,000,000 Nm^3/h are planned for 2002. A further limitation results from the maximum tolerable fuel sulphur content of 2.3 %.

Cross media aspects

The following residues result from flue gas cleaning:

- Fly ash from the electrostatic precipitator (sold to building material industry)
- Sulphuric acid from the activated coke process (sold to chemical industry)

The operation of the flue gas cleaning system needs additional natural gas for the desorption of the SO_2 and reduces the electrical net efficiency of the power plant.

The undersized particles of the activated carbon can be sold and used in plants for the removal of mercury

Operational data

In 1998 the production amounted to 1,487 GWh of gross electricity and 8.4 GWh of district heat. The electrical gross efficiency amounted to 37.5 %. The plant was in operation for 7000 hours, reaching 6,144 equivalent full load hours.

Table 2-55 shows the atmospheric emissions in 1998.

Table 2-55: Atmospheric emission limit values and emissions in 1998

	ELV [mg/Nm^3] at 6 % O_2	Measured emission levels	Specific emissions [g/MWh$_{el}$]	Measurement
O_2-content [%]		6.5		
Operational State		Full load		
Flue gas volume flow rate [m^3/h]		400,000 / 600,000		
Dust [mg/Nm^3]	80	25 - 30$^{1)}$	10.78	continuous
SO_2 [mg/Nm^3]	400	5$^{1)}$	2.16	continuous
Share of emitted sulphur [%]	10	< 1		continuous
NO_x [mg/Nm^3]	200	120 - 135$^{1)}$	60.36	continuous
CO [mg/Nm^3]	250	< 80$^{1)}$	25.86	continuous
HCl [mg/Nm^3]	30	< 0.2 (LOD)		recurring
HF [mg/Nm^3]	10	1	0.43	recurring
As [mg/Nm^3]		0.001 (LOD)		recurring
Cr [mg/Nm^3]		< 0.004 (LOD)		recurring
Ni [mg/Nm^3]		< 0.004 (LOD)		recurring
Hg [mg/Nm^3]		< 0.0005 (LOD)		recurring
Cd [mg/Nm^3]		< 0.001 (LOD)		recurring
Tl [mg/Nm^3]		< 0.001 (LOD)		recurring
Sb [mg/Nm^3]		< 0.001 (LOD)		recurring
Pb [mg/Nm^3]		0.005		recurring
Co [mg/Nm^3]		< 0.001 (LOD)		recurring
Cu [mg/Nm^3]		0.007		recurring
Mn [mg/Nm^3]		0.003		recurring
V [mg/Nm^3]		0.002		recurring
Se [mg/Nm^3]		0.004		recurring
Te [mg/Nm^3]		< 0.002 (LOD)		recurring
Sn [mg/Nm^3]		0.004		individual
Total C [mg/Nm^3]		< 2 (LOD)		individual
PCDD/PCDF [ng TE/Nm^3]		< 0.001 (LOD)		individual

$^{1)}$ Daily mean value at 6 % O_2

*(LOD: **L**imit **Of** **D**etection)*

In 1998 fuel consumption amounted to 1,079.5 kilotons of hard brown coal (equivalent to 0.73 kg/kWh$_{el}$) with a calorific value of 13.2 MJ/kg. The composition of the coal is shown in Table 2-56.

Table 2-56: Average composition of the hard brown coal

C [wt.-%]	35.0
H [wt.-%]	2.37
H_2O [wt.-%]	39.0
N [wt.-%]	0.46
S [wt.-%]	1.0
O [wt.-%]	9.3
Cl [wt.-%]	0.01
Ash [wt.-%]	12.87
F [wt.-%]	0.016

In addition, 4.25 x 10^6 Nm^3 of natural gas were consumed for the desorption process and 302 t fuel oil for the start-up of the boilers. The consumption of major auxiliary materials is shown in Table 2-57.

Table 2-57: Consumption of important auxiliary supplies in 1998

Auxiliary material	Activated Coke	NH_3	NaOH	HCl	CaOH	$FeCl_3$
Application	Flue gas treatment		Feed water treatment			
Consumption [t/a]	4,900	1,340	435	142	9	5
Specific consumption [g/MWh_{el}]	3,300	900	292	95	6	3.4

The wastewater flow rate of the whole plant amounts up to 12,000 m^3/a which means a value of 2 m^3/h at full load operation. Wastewater occurs at the feed water treatment and at the full water softening. After neutralisation and final filtration in a sand filter the wastewater is being discharged to the river with an annual mean concentration of filterable matter of 5 mg/l.

Using a retrofitted reverse osmosis system, the wastewater flow resulting from the regeneration of the feed water treatment system could be reduced by 90 %, thus resulting in 2000 m^3/a of wastewater and a consumption of 20 t/a of NaOH and 20 t/a HCl

The feed water is exclusively provided by rain water and surface water.

Table 2-58 shows the quantities of residues produced in 1998.

Table 2-58: Residues generated in 1998

	Ash	Sulphuric acid	Filter cake from feed water treatment	Screenings	Undersized particles of activated carbon	Ash from cleaning
Quantity [t/a]	100,000	14,000	18.26	3.46	3500	44.22
Specific Quantity [kg/MWh$_{el}$]	6.73E+01	9.42E+00	1.23E-02	2.33E-03		2.98E-02
Utilisation / Disposal	Building material industry, positive value	Chemical Industry, positive value (~ 35 EUR/t in 1992)	Landfill	Composting	Sorbent for HM-separator	Landfill

The emission limit values for sound result from the residential site which is situated between 1,000 and 1,500 m away from the plant. Measures to reduce the emission of sound comprise plated facades, encapsulation of single installations and elastic decoupling of installations from their surroundings. The immission limit values (60 db(a) by day, 45 db (A) by night) at the residential site can be reached with these measures.

Economic Data

The total investment for the two flue gas cleaning systems amounted to 72 Mio. EUR in 1987. The operational costs accounted for 7.9 Mio. EUR/a in 1992 for 5,330 equivalent full load hours. The highest share of this is taken by the costs for the activated coke (3.8 Mio. EUR/a) and maintenance (2.3 Mio. EUR/a). The operational costs already include the payment for the sulphuric acid (0.56 Mio. EUR). The specific O&M costs for the activated coke process amount to 0.007 EUR/kWh$_{el}$ (1992).

Driving force for implementation

The activated carbon process was chosen to minimise SO_2 emissions in a region were acid rain is a major problem. The waste water free operation of the flue gas treatment system and the sulphuric acid production was another reason as the adjacent river has only a small water flow rate. The produced sulphuric acid can easily be sold to the chemical industry. If the alternative lime scrubbing process hade been installed, the produced gypsum could not have been used in the region as there is no gypsum industry nearby.

2.1.14 Example: Pulverised lignite fired boiler with desulphurisation in a fluidised-bed reactor and compound operation with a gas turbine

Description

The presented CHP plant consists of a lignite fired boiler and a natural gas-fired combined cycle unit. The waste heat boiler of the gas turbine is equipped with an additional firing. The produced steam is merged with the steam of the lignite boiler (both 500 °C / 100 bar) and feeds the steam turbine. The lignite boiler produces up to 100 t/h of steam, the waste heat boiler up to 65 (35) t/h with (without) additional firing. The lignite boiler has a rated thermal power input of 78.8 MW_{th}. The steam turbine has a power output of 24 MW_{el} for full load operation of the boiler and the gas turbine (without additional firing) and 18 MW_{el} for single operation of the boiler. The gas turbine has a rated thermal input of 72 MW_{th} and an electrical power output of 25 MW_{el}.

The pulverised lignite is delivered by tank lorries and stored in two silos from where it is transported pneumatically to the four staged twisting burners. The design of the plant allows for a continuous operation of the lignite boiler all the year round. The gas turbine is mainly used in the winter. The production of district heat is realised in heating condensers and in the waste heat boiler. In the summertime the steam can also be cooled in air cooled condensers. The maximum output of heating power arises to 80 MW_{th} with a flow temperature of 135 °C. The additional firing is solely used for peak load and as back-up provider.

The electrical efficiency and the overall energy efficiency both depend on the operational state of the plant. In 1998, for example, the gas turbine was operated almost for the whole year due to the low price for natural gas. This resulted in a high electrical efficiency. In the year 2000 the gas turbine was only in operation during winter times. Thus the electrical efficiency decreased whereas the overall energy efficiency increased. The exact values are summarized in Table 2-59.

Table 2-59: Annual efficiency values for the years 1998 to 2000

Year	Electrical net efficiency [%]	Overall net energy efficiency [%]	Fuel consumption [MWh]
1998	31.9	68.0	977,216
1999	28.9	69.13	804,337
2000	27.53	74.4	778,407

NO_x-control

The gas turbine is equipped with a Low-NOx combustion chamber and works with steam injection in the case of light oil firing. Fuel and air staging as well as flue gas re-circulation are applied in the case of the lignite boiler.

Desulphurisation

The dry desulphurisation process is carried out in a fluidised bed reactor (Lurgi system). The injected hydrated lime ($Ca(OH)_2$) reacts with SO_3, SO_2, HCl, HF and partly with CO_2. The dry reaction product is extracted together with the ash in the subsequent bag filter. water is injected into the reactor to lower the temperature of the flue gas from 130 – 170 °C to 75 °C to get optimal conditions for the chemical reactions. The SO_2 concentrations in the clean gas are beneath 250 mg/Nm^3.

Dedusting

The bag filters and the reactor form a functional unit, as described above. Dust concentrations in the clean gas range well below 20 mg/Nm^3.

The complete set-up of the plant is schematically shown in Figure 2-7.

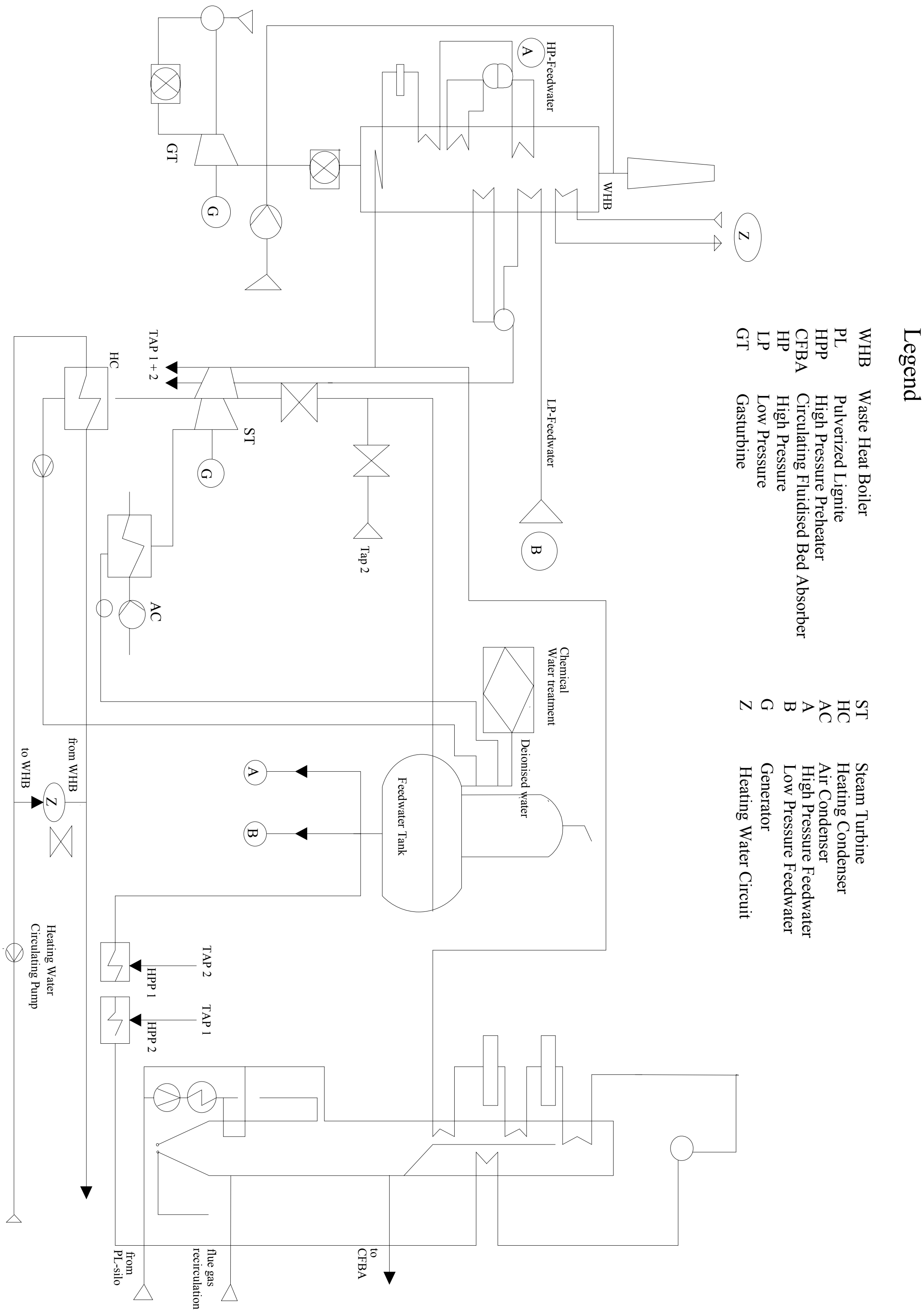

Figure 2-7: Schematic set-up of the CHP plant

Main environmental benefits

Primary and secondary reduction measures lead to low atmospheric emissions. The applied desulphurisation technique ensures low emissions of SO_2, dust, HCl and HF and waste water free operation at the same time.

Applicability

The production facility for the pulverised lignite in the vicinity of the open-cast mine is about 100 km away from the described CHP-plant. The lignite deposits should not be much further away from a CHP-plant to ensure economical operation. Another prerequisite is a certain demand for heat all the year round.

It could be reasonable to equip an existing lignite boiler with a gas turbine. In this case, the presented compound system where the boiler and the gas turbine are connected via the water-steam cycle is more easily to realise than the connection via the flue gas.

Fluidised bed reactors for sorbent injection processes can handle up to 1,000,000 m^3/h of flue gas, which means about 750 MW_{th}.

Cross-media aspects

In the bag filter the reaction product of the desulphurisation process is extracted. It consists of ash, hydrated lime and gypsum.

The operation of the desulphurisation system reduces the boiler efficiency by approximately 2 to 3 %.

Operational data

In the year 1999 232.4 GWh_{el} of net electricity and 326.9 GWh of district heat were produced. This gives 5,164 equivalent full load hours related to the electrical capacity.

Table 2-60 shows the atmospheric emissions of the coal-fired boiler and the gas turbine in 1999.

Table 2-60: Emission limit values and measured emission levels in 1999

	Coal fired boiler		Gas turbine (natural gas)	
	ELV (*1/2-hour mean value at 6 % O_2)	Measured emission level	ELV (*1/2-hour mean value at 15 % O_2)	Measured emission level
O_2-content [%]		7 - 8		14.5 – 15.5
Operational state	78.8 MW_{th}		72 MW_{th}	
Flue gas volume flow rate [m^3/h]		104.950		98,280
Dust [mg/Nm^3]	50	6.6 1) (5 - 35) 2)		
Opacity [smoke no.]			2	0.2 – 0.3 3)
SO_2 [mg/Nm^3]	500	241 1) (200 - 300) 2)		

NO$_x$ [mg/Nm^3]	400	272[1] (240 - 360)[2]	150	18.4[1] (15 - 30)[2]
CO [mg/Nm^3]	250	8.7[1] (0 - 50)[2]	100	6.5[1] (0 - 20)[2]
HCl [mg/Nm^3]	50	0.4 – 6.8[3]		
HF [mg/Nm^3]	3	0.7 – 1.3[3]		

[1] continuous measurement, daily mean value

[2] Interval of continuous measurement

[3] Interval of single measurements

In full load operation 8620 kg/h of lignite and 5144 Nm^3/h natural gas are fired. The properties of the pulverised lignite are put together in Table 2-61.

Table 2-61: Properties of the pulverised lignite (Average of several years)

Short analysis	
Water content [%]	10.5
Ash content [%]	6.0
Volatiles [%]	45.5
Fixed carbon [%]	38.0
Heating value [MJ/kg]	21.0
Elementary analysis	
Carbon [Gew.-%]	56.5
Hydrogen [Gew.-%]	4.0
Oxygen [Gew.-%]	21.5
Nitrogen [Gew.-%]	0.7
Sulphur [Gew.-%]	< 0.8
Ash fusibility	
Softening temperature [°C]	> 1,100
Hemisphere temperature [°C]	> 1,200
Flow temperature [°C]	> 1,300

The desulphurisation process consumes 260 kg/h of hydrated lime (equals 0.03 kg/kWh$_{el}$). Furthermore 4.1 m^3/h of water are injected into the fluidised bed reactor.

The total waste water flow rate amounts to 9 m^3/h. It is dumped to the sewer without preliminary treatment. Sources for waste water are the feed water treatment, the cleansing waters from the filters of the heating circuit and the water-steam-cycle.

The water consumption is minimised due to the closed cooling circuit and the chosen desulphurisation technique. The concentrations of impurities in the waste water for the year 1999 are put together in Table 2-62.

Table 2-62: Concentrations of impurities in the wastewater of the CHP-plant (9m^3/h)

	Mean values derived from 12 single measurements [mg/l]	Specific load [g/MWh$_{el}$]
chlorine	27	5
COD	55	10.1
phosphor, total	3.9	0.72
nitrogen, total	13.5	2.5
filterable matter	< 10 ml/l	< 1.8 l/MWh$_{el}$
sulphate	348	64
sulphide	< 0.8	0.15

Table 2-63 shows the quantities of residues produced in 1999.

Table 2-63: Residues generated in 1999

	Boiler ash	Mix of fly ash, hydrated lime and gypsum	Sludges from regeneration of ion exchanger	Filter material	Used detergent from gas turbine cleansing
Quantity [t/a]	66	6429	29	1	1
Specific Quantity [g/MWh$_{el}$]	284	27,700	125	4	4
Utilisation / Disposal	landfill	filler material for surface mining		landfill	

The emission limit values for sound result from the residential site which is situated between 150 and 450 m away from the plant. Measures to reduce the emission of sound comprise exhaust silencers, encapsulation and acoustic insulation.

Economic Data

The total investment amounted to 73.3 Mio. EUR in 1997, which is equivalent to 1496 EUR/kW$_{el}$. The investment for the desulphurisation plant arose to 5.6 Mio. EUR (114 EUR/kW$_{el}$).

Driving force for implementation

The plant was built to replace an old heating station. The planners decided to use a compound system with a lignite boiler and a gas turbine to use the advantages of both techniques. The operation of the lignite boiler offers stable fuel prices in the long run whereas the gas turbine allows for an economical peak load operation.

2.1.15 Example: Industrial power plant with atmospheric circulating fluidised bed combustion for lignite

Description

The plant has a natural draught boiler and a ACFBC with a rated thermal power input of 119 MW and a net electrical power of 33 MW_{el}. It is fired with raw lignite and/or dried lignite. The produced electricity is used in the nearby lignite mine. Furthermore process steam (260°C/13.5bar) and district heat for 930 households is produced. The plant was commissioned in 1994

Primary NO_x emission control

Low combustion temperatures (about 850 °C) and air staging reduce the formation of thermal NO_x.

Sulphur oxide emission control

Sulphur oxide emission control is realised by adding lime to the fluidised bed combustion chamber. This integrates the sulphur in the bed material. In 1999 the separation efficiency was about 91 %. In general, this can be further increased by increasing the lime addition.

Dedusting

For dust control an ESP with separation efficiencies of > 99.9 % is installed.

Main environmental aspects

Low emissions can be realised without the need of secondary desulphurisation and $DeNO_x$. A wide range of fuels can be fired including coal, biomass and waste with a high content of sulphur and ballast.

Applicability

ACFBC plants suit well for the replacement of old boilers when there is only little amount of space as they build very compact. Furthermore a wide range of fuels can be fired. The electrical power output of single units can reach up to 250 MW_{el}.

Cross media aspects

Bed ashes are produced (18.8 kt/a) as well as fly ash during operation of the ESP (35 kt/a). The ashes are used for the combined sulphuric acid /cement production and for landscape architecture. Lime sludges from the feed water treatment are used internally for desulphurisation.

Operational Data

In 1999 the plant was in operation for 8,081 hours and showed a net electricity production of 238 GWh_{el} and 138 GWh process heat and district heat. The overall energy efficiency was of the plant was 41.7 %.

The following atmospheric emissions were measured.

Table 2-64: Emission limit values and measured atmospheric emissions in 1999

	Monitoring	ELV (5% O_2)	Annual mean concentration at 5 % O_2	Specific emissions [kg/TJ Input]
Dust [mg/Nm^3]	continuous	25	10	4.5
SO_2 [mg/Nm^3]	continuous	400	393	177.4
Sulphur emission rate [%]	continuous	15	9	-
NO_x [mg/Nm^3]	continuous	200	168	76.1
CO [mg/Nm^3]	continuous	250	0.2	0.1
N_2O [mg/Nm^3]	continuous	-	26	11.8
HCl [mg/Nm^3]	individual	150	4$^{1)}$	1.8
HF[mg/Nm^3]	individual	10	0.5$^{1)}$	0.2

$^{1)}$ mean value of individual measurements

295 kilotons of lignite were fired. The characteristics of the lignite is shown in Table 2-65.

Table 2-65: Characteristics of the fired lignite

	Mean values for the reference year
H_u [MJ/kg]	10.8
Water content [%]	50
Sulphur content [%]	1.7

The consumption of the most important auxiliary supplies are shown in Table 2-66.

Table 2-66: Consumption of important auxiliary supplies in 1999

Auxiliary material	Limestone	NaOH	HCl	$FeCl_3$
Application	Additive	Water treatment		
Consumption [t/a]	40,100	606		147

The total wastewater flow amounts to 70 m^3/h. The major part of this flow (61 m^3/h) results from the cooling system. The rest is made up of house sewage and wastewaters from decarbonisation and neutralisation installations. The condensate treatment reduces the water demand of the plant.

Concentrations of impurities in the wastewater are given in Table 2-67.

Table 2-67: Concentrations of impurities in the wastewater in 1999 (mean values)

	AOX	COD	P_{total}	NH_4^+	NO_2	NO_3	Filterable matter
Range of measured concentrations [mg/l]	0.02 - 0.09	<15 - 27	0.05 - 0.92	<0.01 - .0.26	<0.05 – 0.23	0.62 – 4.4	<10 – 43
Mean concentration [mg/l]	0.04	18	0.26	0.07	0.07	2.9	14

Residues accrued are lubricants, oils, sludges from oil separators and sludgy residues from the bottom of tanks.

Economic Data

There are no absolute values for investments or costs available but Table 2-68 presents the relative share of the single cost centres in the prime costs.

Table 2-68: Repartition of prime costs for heat and electricity production

	Type of costs	**Cost centre**	**Share in initial costs**
Production of heat	Fuels	Lignite, light fuel oil	37.0 %
	Resources	Raw water, drinking water, limestone, ash, electricity, other resources (lubricants,...)	24.8 %
	Maintenance	Construction works, maintenance of electrical systems and machines, cleaning, disposal, lab	4.7 %
	Other costs	Depreciation, insurance, staff, interests	33.5 %
	Total (Heat production)		100 %
Production of electricity	Heat (steam)		75.4 %
	Resources	Cooling water, other resources (lubricants,...)	2.7 %
	Maintenance	Construction works, maintenance of electrical systems and machines, cleaning, disposal, lab	2.6 %
	Other costs	Depreciation, insurance, staff, interests	19.3 %
	Total (electricity production)		100 %

The data given in Table 2-68 relate to the resource demand in 1996. In that year the lime addition was realised with a Ca/S ratio of 3.1/1 which resulted in SO_2 concentrations in flue gases of about 200 mg/Nm^3. In 1999 the Ca/S ratio was lowered to 1.7/1 with related SO_2 concentrations just below 400 mg/Nm^3. This operation mode results in a lower consumption of limestone and produces less bed ashes to be disposed of.

Driving force for implementation

The former plant had reached the end of its technical lifetime after 70 years and had to be replaced. In addition, new emission limit values came into force which can be met by the described plant.

2.1.16 Recent developments: Pressurised fluidised bed combustion

In Germany the first lignite fired power plant with pressurized fluidised bed combustion in the world is in initial operation since April 1999. The energy content of the exhaust gas is additionally used by expansion in a gas turbine. An electrical net efficiency of 42.3 % is expected. In CHP operation the overall energy efficiency is supposed to reach 87 %. The boiler is fired with dried and grinded lignite and has a rated thermal power input of 220 MW. Limestone is added for sulphur oxide emission control. One pressurised tank (12 bar) contains all parts of the steam generator, the ash removal, the SNCR system and the dedusting unit. The coal supply and the ash removal are equipped with sluices to keep the pressure in the tank. The flue gas is expanded in the gas turbine and subsequently dedusted with a fabric filter. To ensure the production of steam the plant is equipped with two peak load boilers. The investment for the whole plant amounts to 177 Mio. EUR.

2.1.17 Emerging Technologies: Pilot plant for a pre-dryer of lignite with low temperature heat

Description

This recently developed technology of drying provides a gain in efficiency of lignite plants of about 4 to 5 percentage points in theory.

The task of the technique is to dry the lignite, being as wet as coming directly from the pit, with low temperature heat of about 120 to 150 °C instead of hot flue gas of 1000 °C. Furthermore, the energy required to evaporate the water content of the lignite is regained by condensing the vapour. Two different processes for this are available. The mechanical-thermal dewatering (German abbreviation MTE) 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 of lignite has already achieved a higher stage of development. It is the drying in a fluidised bed apparatus with internal utilisation of waste heat. The steam dissipating from the dryer is separated from its contents of lignite particles by an electrostatic precipitator. After that, it is compacted again by a compressor which works in an open heat pump process, and is condensed finally inside of the pipe coils, which are used as heating surface 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, being 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 %.

Main environmental benefits

This technique is supposed to allow for a significant rise of efficiency (4- 5 percentage points) of lignite fired power plants.

Applicability

New power plants must be designed for this dry lignite. Existing plants can usually be equipped with this technique at least for a certain share of the total fuel input.

Economic data

No representative data is available, as the existing plants are in the pilot-phase. But under current liberalized market conditions, the implementation of this technique seems not to be economically viable.

Driving force for implementation

Increasing the efficiency of lignite fired power plants.

2.1.18 Emerging Technologies: Pulverised lignite fired dry bottom boiler with primary NOx control, secondary desulphurisation and utilisation of waste heat

Description

The plant described here is currently under construction. The start up is supposed to be in the end of 2002. It is a power plant with condensing steam turbine, consisting of one unit with a rated thermal input of 2,136 MW_{th}. Further information for technical data is given in Table 2-69.

Table 2-69: Technical data for operation at the design point and at full load

	Unit	**Design point**	**Maximum of design**
Rated thermal input	MW	2,136	2,306
Consumption of lignite with guaranteed characteristics	t/h	836	847
Gross energy output	MW	1,012	1,027
Net energy output	MW	965	980
Net efficiency	%	43 – 45	43 – 45
Steam output	t/h	2,620	2,663
Main steam pressure/-temperature	bar / °C	274.5 / 580	274.9 / 580
Reheater pressure/-temperature	bar / °C	59.5 / 600	60.3 / 600
Condenser pressure	mbar	28.9 /35.5	29.1 / 35.8
Preheater of feed water	number of stages	10	10
Feed water temperature	°C	294	295
Utilisation of waste heat	°C	350/160/100	350/160/100

The flue gas cleaning technologies used in this generating unit correspond to the techniques used in German lignite power plants since the end of the eighties. For primary NO_x - reduction low-NO_x-burners, staging of air and staging of fuel are used. Further on, an electrostatic precipitator and a wet desulphurisation plant are installed. By optimising the wet scrubber, the energy demand of it was reduced by 20% compared to its precursor.

The main benefit of this unit is its high net electrical efficiency, which is supposed to mount up to 43 % and more at any rate. This is supposed to be realised by the following measures:

- supercritical steam parameters (see above): this is possible only by using recently developed materials for the turbine
- optimising of the auxiliary power requirements: of mills, ventilators, forced draught; reducing the power demand of the wet scrubber of 20%, minimising the consumption of water and steam for soot removing at the heating surface
- reducing the surplus of combustion air to 15 %
- process optimising: ten- fold preheating of the feed water with HD- bleeding and a temperature of the feed water of 295 °C; several improvements in operating conditions
- condenser pressure: the optimised natural draught cooling tower provides a pressure of 28.2/34.2 mbar at the condenser

- utilisation of waste heat: the flue gas is cooled off from 350°C to 160°C by an air preheater with an air preheater- bypass- economizer for preheating the feed water; it is the first time, such a system is used in a lignite power plant. Further on, heat exchangers upstream the desulphurisation plant are cooling the flue gas to 100 °C, preheating the combustion air at the same time.
- dissipation by cooling tower: no reheating of the flue gas is necessary after leaving the desulphurisation
- steam turbine: optimised turbine blades and widened exit ensure an efficiency of 51 % at the given steam parameters

In Table 2-70, the gains in efficiency achieved by the individual measures are shown as percent points of efficiency increase compared to a 600 MW generating unit in 1976, operating at an efficiency of 35.5 % and at the same site.

Table 2-70: Gains in efficiency by individual measures

	Gain in efficiency in % points compared to a 600 MW generating unit in 1976, operating at η=35.5%
Energy power requirement	1.5
Process optimising	1.6
Steam parameters	1.6
Steam turbine	2.3
Condenser pressure	1.4
Utilisation of waste heat	1.3
Total	9.7

Main environmental benefits

The main benefit of this plant is its high electrical efficiency. The atmospheric emissions are reduced by primary and secondary measures and therefore all limit values for emissions can be guaranteed. However, exact data for the emissions can not be given yet. All of the waste water is either treated or reused.

Applicability

In general, technologies described here can be used in any new construction of pulverised lignite fired power plants.

Cross media aspects

The residues accruing from the flue gas cleaning are:

- Electrostatic precipitator: fly ash: is put together with the waste water of the desulphurisation plant to produce stabilised material
- Desulphurisation plant: waste water (reuse: see above)
  gypsum: utilisation in gypsum industry or disposal

The energy demand of the flue gas cleaning plants reduces the overall energy efficiency.

Operational data

Material consumption

While operating at the design point, the generating unit requires 836 t/h of raw lignite. Details for the quality of lignite used are given in Table 2-71. For desulphurisation, 72 t/h of process water and about 8 t/h lime are utilised.

Table 2-71: **Required characteristics of the raw lignite**

	Mean values	Range of values for lignite from surface mining
Calorific value [MJ/t]	8,502	7,800 – 8,903
Water content [%]	56.2	53.8 – 57.8
Pure carbon [%]	37.9	35.1 – 39.2
Ash content [%]	5.9	4.4 – 10.8

Waste water

For the cooling tower, an average supplement of 1,400 t/h of cooling water is needed.

The volume of the waste water flow can be minimized by achieving high concentrations in the closed circuit cooling and by partly re-utilisation of the waste water incurring at the cooling tower for the desulphurisation plant.

Residues

The ash accruing from the flue gas cleaning is moistened with waste water from the desulphurisation plant and deposited in opencast pits.

Most of the gypsum produced (ca. 15 t/h) is used in gypsum industry. Merely deficient charges are deposited together with the lignite ash (about 42 t/h of fly ash, 13.7 t/h of boiler ash) as stabilized material in an opencast pit which is authorized for the depositing. Reagent particles of the waste water treatment are utilised in industries for lime and construction materials. Sludge containing lime accruing from the waste water treatment is used in the desulphurisation plant, partly replacing raw lime stone.

Economic data

The total investment for the plant will sum up to about 1.2 billion € (1998) taking into account all measurements required at the site and all internal and external services. The generating unit itself will have an investment of about 0.93 billion €.

Driving force for implementation

This plant shall replace six generating units, each with 150 MW_{el}, which have been erected in the years from 1954 to 1962. Their net electrical efficiency of about 30 % entailed that they could not be operated in an economically reasonable way. For the new plant, the aim to achieve high efficiencies was pursued consequently, tending also to get experience in new technologies for the improvement of lignite power plants.

2.1.19 Emerging Technologies: Pulverised hard coal fired dry bottom boiler with primary and secondary measures for NO_x- reduction, secondary desulphurisation and utilisation of waste- heat

Description

This plant is currently in the planning phase and is to be started up in 2003 presumably. The rated thermal input for the generating unit is 740 MW_{th}. In Table 2-72, further operational data are summarized.

Table 2-72: Technical data for the operation at the design point and for maximum load

		Operation at design point
Rated thermal input	MW	740
Gross energy output	MW	353
Net energy output	MW	329
Net efficiency	%	47
Steam output	t/h	930
Main steam pressure / temperature	bar / °C	290 / 600
Reheater pressure / temperature	bar / °C	51 / 620
Condenser pressure	mbar	35
Feed water temperature	°C	315
Utilisation of waste- heat	°C	110

The flue gas cleaning technologies used in this generating unit correspond to the techniques used in German hard coal boilers since the end of the eighties. For primary NO_x - reduction low-NO_x- burners are used. In addition, a SCR, an electrostatic precipitator and a wet desulphurisation plant are installed. With these measures, all limit values for emissions can be guaranteed. In order to avoid diffuse emissions of hard coal, the flue gas of the hard coal silos is also cleaned.

The main benefit of this generating unit is the high electrical net efficiency, which is supposed to reach 47 % and more. This is supposed to be realised with the following measures:

- supercritical steam parameters (see above, Table 2-72): this is possible only with the utilisation of recently developed materials
- cooling tower. no reheating of the flue gas is needed after leaving the desulphurisation plant
- steam turbine: optimised turbine blades lead to an efficiency rate of the turbine of 91 to 92 %
- water-steam circuit with thermo- compression
- optimised concept for reverse-flow cooling

Main environmental benefit

The main benefit of this plant is the high electrical efficiency. The atmospherical emissions are reduced by primary and secondary measures and therefore all limit emission values can be guaranteed. However, exact data for the emissions can not be given yet.

Applicability

In general, technologies described here can be used for any new construction of hard coal fired power plants.

Cross- media aspects

The residues accruing from the flue gas cleaning are:

- Electrostatic precipitator: fly ash: utilisation in construction industries
- desulphurisation plant: wastewater: wastewater treatment with flocculation, precipitation and sedimentation
  gypsum: utilisation in gypsum industries

The energetic demand of the flue gas cleaning plants reduces the overall energy efficiency.

Operational Data

Of the operational data planned, only data for the wastewater flow is given yet. While operating at full load, a wastewater flow of 80 m^3/h will accrue at the desulphurisation plant, the treatment of the cooling water and the ash removal. In addition to this, the cooling tower is supposed to operate with 2,000 m^3/h of cooling water.

Economic Data

The total specific investment will sum up to about 850 €/kW_{el} (2000). About 30 % of it will be needed for the steam generator.

Driving force for implementation

This plant will replace two generating units of each 152 MW_{el}, which were started up in 1963 and are no longer operating in an economical reasonable way. For economic reasons, the efficiency of the plant was optimised consequently.

2.2 Combustion of biomass

2.2.1 Example: Spreader-Stoker-plant with waste wood and wooden by-products as main fuel

Description

The spreader- stoker technique described here will be illustrated with three examples of almost identical chip board plants. In Table 2-73 all substantial parameters for the three combustions are summarized. These plants serve mainly for the valorisation of wood residues and wood dust and provide the heat demand of the chip board production. Therefore, a high and constant energy demand is ensured.

Table 2-73: Technical data for the three examples of plants

Example	**I**	**II**	**III**
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)*
Electric power brutto [MW]		16.6 (maximal) 11 (annual mean)	13.3
Availability	operational life cycle times > 5,000.h, availability 99.8 %	operational life cycle times > 5,000.h	operational life cycle times > 5,000.h
Maximal rated thermal input [MW]		63	35 + 6.7
Overall energy efficiency, brutto [%]		96.6 max.	ca. 85 %
Main steam parameters		450 °C, 67 bar	455 °C, 70 bar
Main fuels	Production residues, waste wood, railroad sleepers, etc.		

The following description of the technique refers to all of the three example plants, as far as not specified otherwise. The spreader- stoker technique is a combustion on an air cooled travelling- grate stoker, the fuel being evenly spread on the grate by a injection- stoker, which throws the particles in. While the bigger pieces are evenly burned in a fixed bed combustion on the grate, the little 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. Therefore, the air rate can be minimized (O_2- content in the raw gas of less than 3 %), which reduces also the NO_x emissions.

The formation of a fluidised bed is possible because of the velocity of the flue gas being similar to the velocity occurring in fluidised bed combustions. The formation of a fluidised bed means also a staging of the fuel, supporting low-NO_x combustion. Also the low maximal temperature of 1,250 °C supports this effect.

Half of the air is injected by a jet tray, the other half is blown in at high pressures 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 realizes 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 minimization of CO and NO_x is at 1,300 to 1,400 °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 prevents also the formation of boiler slag and therefore results in high operational life cycle times (> 5,000 h).

For the combustion of abrasive dust, there are 4 pulverised-fuel burners installed in plant III with plug nozzles burners at a maximal rated thermal input of 28 MW. These can also be driven by extra light fuel oil.

The heat is used mainly for the drying of splints. In plant II, up to 26 t/h are dried in rotary dryers, which means that the moistness[1] 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 form 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 III fit out supplementary with a SNCR- installation. As reducing agent ammonium hydroxide with 25 mass- % of NH_3 is used, which is stored over ground in a tank of stainless steel. Furthermore, plant III is equipped with an adsorption process as separator. This combined duct sorbent injection (dry adsorption) means the injection of a ground mix of active carbon / coke and hydrated lime (= adsorbent) in the flue gas flow and is separated

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[1] definition of moistness: mass of water/ (mass of water+ mass of dry wood);

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.

Main environmental benefit

By using wood as a biomass fuel one can emanate to have an almost evened 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.

Coevally, the combustion technology allows to achieve low emissions of NO_x and CO of the raw gas. Combined with reduction measures like bag filters, SNCR and duct sorption plants very low concentrations can be attained for all sorts of pollutants.

Applicability

The spreader- stoker technique has approved itself for a broad range of fuels and excels the fluidised bed technology especially for the use of fuels with highly heterogeneous particle sizes and contaminations (as for example metal pieces).

The plants described here are especially designed for applications in the chip board and MDF board industry and can operate in an economically reasonable way there because of the energetic valorisation of wood residues and the continuous demand of heat. For locations with similar characteristics the application of this technology is also reasonable.

Cross media aspects

High amounts of ash are emerging from these plants. Furthermore, the water treatment produces waste water. Also, the adsorbent used in the flue gas cleaning plants has to be deposited.

Operational data

The atmospheric emissions accruing from plant II are shown in Table 2-74.

Table 2-74: Limit values and measured atmospheric emissions in 2000/2001

	Monitoring	Statistics	ELV (at 11 % O_2)	Measured value (at 11 % O_2)
Dust [mg/Nm^3]	continuous	daily mean value	10	3.4 – 4.3**
CO [mg/Nm^3]	continuous	daily mean value	80	46.7 – 58.3**
NO_x [mg/Nm^3]	continuous	daily mean value	200	183.9 – 190.7**
C total [mg/Nm^3]	continuous	daily mean value	10	1.1 – 1.2**
HCl [mg/Nm^3]	continuous	daily mean value	10	8**
Hg (gas) [mg/Nm^3]	continuous	daily mean value out of 2-hours-mean-values	0.03	0.001**
Dioxins/furans [ng TE/Nm^3]	continuous sampling, single values	mean of 20 days	0.025*	0.0019
PAH [mg/Nm^3]	Continuous sampling, single values	mean of 4 days	0.02*	0.0003
Cd [mg/Nm^3]	continuous sampling, single values	mean of 4 days	0.01*	0.0005
As/Pb/Cu/Ni/Sn (in the particles) [mg/Nm^3]	continuous sampling, single values	mean of 4 days	0.5*	0.053
As [mg/Nm^3]	continuous sampling, single values	mean of 4 days	0.1*	0.0005

* value for precaution

**intervals based on three daily mean values in January 2001

For plant III a consumption of 120,000 t wood per year is estimated. For plant II, the different types of fuels are used in the amounts listed in Table 2-75.

Table 2-75: Contribution of the different fuel types to the total fuel consumption in plant II

Fuel	Wood dust	Board coupage	Wood residues out of packaging / loading	Special fuels (railroad sleepers)	Timber	Biomass pellets
Contribution to the total fuel consumption	30 %	10 %	10 %	max. 20 %	varying	varying, ca 15,000 t/a

The size of the pieces should be below 100 mm. However, a few pieces can achieve up to 250 mm. This limit is because of the transport devices, e.g. screw conveyors. For the preparation of all fuels for a plant of 60 MW by a hacker, costs of 0.5 €/t were given.

The accruing boiler ash and fly ash are used in the construction industry.

Economic data

The investment for plant II amounted to 36 Mio. €.

Driving force for the implementation

The reasons for the implementation of these plants were the possibility to re-use the own by-products and the need to deposit the wood residues in an economically reasonable way.

2.2.2 Example: Circulating atmospheric fluidised bed combustion with wood as main fuel

Description

The plant consists of two units with a total rated thermal input of 90.5 MW, a gross electrical power of 19.8 MW_{el} and a net electrical power of 13 MW_{el}. It was commissioned in 1992 and 1996 respectively and is used in a chipboard factory to produce electricity and process heat from wood residuals. Next to the residues from the own production process, also bark and other wood residues are fired. The flue gas cleaning system consists of a pulse-jet fabric filter for dust removal. The NO_x emission levels can be reached by the comparably low temperature of the combustion, by air staging (3 stages for the combustion air inlet) and flue gas re-circulation. Because of the low sulphur content of wood no lime must be added, whereas a system for the addition of lime is installed for precautionary reasons.

Thermal oil is used in the process for heat transfer.

Main 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 anymore. Only wood without contamination by wood preservatives is burned. The production of electricity and process heat allows for an overall energy efficiency of 85 %. Wastewater only occurs in small amounts (0.3 m^3/h; 2,592 m^3/a in 1999) and is fed into the municipal sewage system.

Applicability

The fluidised bed combustion is well known for the wide range of fuels which can be burned. Therefore, no limitations should result from the fired fuel. Due to the compact design of these plants the space demand is quite small.

Cross-media aspects

The boiler operation and dust removal produce a certain amount of ashes.

Operational data

In 1999 102,589 MWh_{el} of net electricity and 634,223 MWh of process heat (= 741,456 tons of steam) were produced. In this year a net electric efficiency of 15.8 % and a net thermal efficiency of 68 % was achieved. The overall energy efficiency was 85 %. The two units were in operation for 8,021 and 6,031 hours respectively mainly in part load. Table 2-76 lists the measured atmospheric emissions in 1999.

Table 2-76: Atmospheric emission limit values and emissions in 1999

	Monitoring	ELV at 7 % O_2	Emission values at 7 % O_2	
			Unit 1	Unit 2
O_2-Content [%]			5 – 5.5	6.5 – 7.5
Flue gas volume [m^3/h]			33,153	86,453
Dust [mg/Nm^3]	continuous	17	$4^{1)*}$	$2.2^{1)*}$
SO_2 [mg/Nm^3]	continuous	165	$2.9^{1)*}$	$2.3^{1)*}$
NO_x [mg/Nm^3]	continuous	350	$164^{1)*}$	$339^{1)*}$
CO [mg/Nm^3]	continuous	200	$147^{1)}$	$178^{1)}$
HCl [mg/Nm^3]	continuous	25	$7.3^{1)*}$	$8.8^{1)*}$
HF [mg/Nm^3]	individual	1.7	0.04	0.1
Dioxins/Furans [ng TE/m^3]	virtually continuous	0.1	0.013	0.006
Σ Cd,Ti [mg/Nm^3]	individual	0.1	0.004	0.003
Hg [mg/Nm^3]	individual	0.1	0.001	0.001
Σ Heavy Metals [mg/Nm^3]	individual	0.8	0.015	0.006
Total organic C [mg/Nm^3]	individual	40	2.0	2.0

$^{1)}$ Annual mean value

*The value is almost equivalent to daily mean values as the unit operates quasi continuously..

The low SO_2 concentrations are not representative, as they strongly depend on the fuel. Thus, SO_2 concentrations up to 50 mg/Nm^3 are possible for certain fuels.

The two units consumed 360,916 t/a (25.8 t/h) wood, 170,000 Nm^3/a natural gas and 3.943 t/a 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 2-77.

Table 2-77: Characteristics of the burned wood

Lower heating value [MJ/kg]	14.7
Sulphur content [wt.-%]	< 0.1
Water content [wt.-%]	18
Ash content [wt.-%]	4

The water discharges (0.3 m^3/h) result from the ash cooling and from the feed water treatment. After neutralisation the wastewaters are discharged to the sewer.

The only residues from the process are ashes as listed in Table 2-78.

Table 2-78: Quantities of ashes generated in 1999

	Bed ashes	Fly ash
Quantity [t/a]	1,314	7,726
Specific Quantity [g/kWhel]	13	75
Utilisation / Disposal	Dump cover (market price: - 25 €/t)	Filling material for mining (market price: - 50 €/t)

The emission limit values for sound result from the residential site which is situated between 400 and 800 m away from the plant. Measures to reduce the emission of sound comprise acoustic absorbers, acoustic insulation and overhead noise barriers. Immission values of 25 dB(A) for 400 distance and 18 dB(A) for 800 distance can be reached with these measures.

Economic data

The investment for the whole plant mounted up to 51,3 Mio. EUR. The erection of the first boiler was subsidised by the government. The investment covered by the operator amounted to 21.8 Mio EUR for unit 1 and 20.8 Mio. EUR (including stake of boiler producer) for unit 2. In 1999 the fixed costs were 6.9 Mio. EUR, the variable costs 3.06 Mio. EUR.

The full cost for the production of steam amounted to 8.46 EUR/t and to 0.077 EUR/kWh$_{el}$ for electricity.

Driving force for implementation

The main motivation for the erection of the plant was the energetic use of the own production residues as far as they are not appropriate any more for substance recycling. The plant covers the heat demand for the production of chip boards and fiber slabs. Furthermore, the subsidies from the government, which were paid to promote the forestry in a structurally weak area, also played a role.

2.3 Combustion of fuel oil

2.3.1 Example: Heavy fuel oil fired boiler with retrofitted flue gas treatment

Description

The two identical units have a gross power production capacity of 2 x 420 MW$_{el}$ and a net electrical capacity of 2 x 386 MW at a rated thermal input of 2 x 1007 MW. The electrical net efficiency amounts to 39.6 % in the design point. Crude oil is transported via pipelines to the nearby refinery where heavy fuel oil is produced. The plant was commissioned in 1973 and 1974 and retrofitted with flue gas treatment installations in 1990 and 1994. These comprise a wet desulphurisation with a separation efficiency > 90 % and a SCR-installation in high-dust position with a removal efficiency > 80 % Furthermore the lining of the inner side of the 180m high stack with GRP (glass reinforced plastics) reduced the emission of acid particles. The boiler (Benson, two-draught) is equipped with 14 low-NO_x burners (bottom firing), over fire air and combustion air preheating.

The oil is stored in 5 tanks with a total volume of 340,000 m^3. Two of the tanks are isolated to store 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 %.

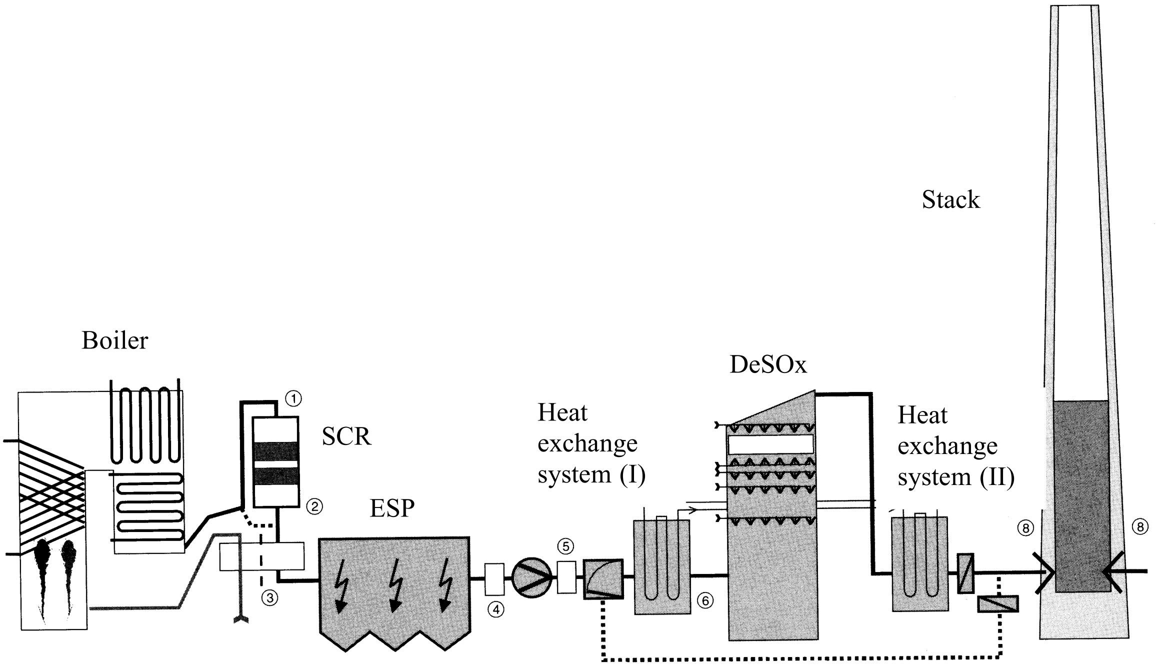

Figure 2-8: **Schematic overview of the flue gas path**

Main environmental aspects

The retrofitted flue gas treatment allows for comparatively low concentrations of SO_2 and NO_x in the clean gas. The retrofitting of the stack has strongly reduced the immissions of acid particles in the neighbourhood of the plant (distance < 1.5 km).

Applicability

The secondary flue gas treatment can be added to existing heavy fuel oil fired boilers. The retrofitting of the stack with regard to acid particulate emissions depends on local conditions. Here, the concentration of SO_3 in the clean gas is the important parameter as it is soluble in water and can condensate 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 aspects

Fly ash results from ESP operation. The wet FGD produces wastewater and gypsum. The operation of the flue gas treatment installations reduces the electrical net efficiency of the plant.

Operational data

In 1998 the first unit produced 443.5 GWh_{el} of net electricity during 1544 hours and the second one 299 GWh_{el} during 1017 hours in operation. The annual electrical mean net efficiency amounted to 36.7 % and 961 equivalent full load hours were reached.
The atmospheric emissions in 1998 are shown in Table 2-79.

Table 2-79: Atmospheric emission limit values and emissions in 1998

	Monitoring	ELV [mg/Nm^3] at 3 % O_2	Measured emission levels [mg/Nm^3] (annual mean value at 3 % O_2)		Specific emissions [g/MWh_{el}]	
			Unit 1	Unit 2	Unit 1	Unit 2
O_2-content [%]	continuous		4.5	4.5		
Flue gas volume flow rate [m^3/h]	continuous		1.3E6 (Full load)	1.3E6 (Full load)		
Dust [mg/Nm^3]	continuous	50	10	15	20.5	30.2
SO_2 [mg/Nm^3]	continuous	400	50 – 250	50 – 250	52	235
NO_x [mg/Nm^3]	continuous	150	121	131	331	355
CO [mg/Nm^3]	continuous	175	50	50	20.5	20.7
HCl [mg/Nm^3]	individual	30	0.2 1)	0.1 1)	0.08	0.04
HF [mg/Nm^3]	individual	5	< 0.1 1)	< 0.1 1)	< 0.04	< 0.04
NH_3 [mg/Nm^3]	individual			< 0.1 1)		< 0.04

1) mean value of individual measurement results

Some 179 kilotons of heavy fuel oil were fired, which means a specific consumption of 0.242 kg/kWh_{el}. The characteristics of the fuel are presented in Table 2-80.

Table 2-80: Properties of the heavy fuel oil fired in 1998

LHV [MJ/kg]	40 - 41
Viscosity [mm^2/s]	< 450
Sulphur content [%]	< 3.5 %
Ash content [%]	0.056

The consumption of important auxiliary materials is shown in Table 2-81.

Table 2-81: Consumption of important auxiliary supplies in 1998

Auxiliary material	Consumption [t/a]	Specific consumption [g/MWh$_{el}$]
HCl, 30 %	122	160
NaOH, 50 %	41	36
Slaked lime	20	27
Crushed limestone	9,900	13,500
$FeCl_3$, 40 %	12.6	19
NaOH, 25 %	9.8	10
NH_3, 100 %	458	620

The once-through cooling system needed 97,149,872 m^3/a, which is equivalent to a specific demand of 72,000 m^3/h at full load in total. Wastewaters are produced during the regeneration of the full water softening installation. The annual mean flow rate of these waters amounts to 12 m^3/h. The average AOX concentration is < 1 mg/l, which is equivalent to < 0.015 g/MWh$_{el}$. After adjustment of the pH-value these wastewaters are released to the receiving water. Another major source for wastewater is the wet FGD. The wastewater flow rate at full load is usually 10 m^3/h but can reach values up to 15 m^3/h. The wastewater is treated and then discharged to the receiving water with mean concentrations of impurities as shown in Table 2-82.

Table 2-82: Concentrations of impurities in the wastewater of the desulphurisation plant after treatment (mean values in 1998)

	Limit values	Mean values	Number of measurements as basis for mean values	Specific load [g/MWh$_{el}$]
pH-value		9.2	77	
COD [mg/l]	150	27.9	27	0.83142
N_{total} [mg/l]		85	1	2.533
Zn [mg/l]	1	0.01	13	0.000298
Cr [mg/l]	0.1	< 0.1	1	< 0.0003
Cd [mg/l]	0.05	< 0.005	27	< 0.00015
Cu [mg/l]	0.5	< 0.1	1	< 0.0003
Pb [mg/l]	0.1	< 0.1	1	< 0.0003
Ni [mg/l]	0.5	0.028	4	0.0008344
V [mg/l]		0.03	27	0.000894
Filterable matter [mg/l]	30	7.3	77	0.21754
Sulphate [mg/l]	2,000	2130	27	63.474
Sulphite [mg/l]	20	< 20	(only at commissioning)	< 0.6
Fluoride [mg/l]	30	3.3	11	0.09834
Hg [mg/l]	0.05	0.002	27	0.0000596
Toxicity for fish		< 2	(only at commissioning)	

To reduce the emissions from wastewaters the waters from regeneration of the cationic demineralisation for the condensate are injected into the boiler.

A combined operational state, which means 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.

The changing of the resin of the ion exchanger in one of the full water softening installations could reduce the water consumption for the regeneration. A further reduction of water demand could be realised by recirculation of the condensate and partly recirculation of the filtrate from the gypsum dewatering into the FGD-circuit.

Table 2-83 shows the quantities of residues produced in 1998.

Table 2-83: Residues generated in 1998

	Insulation	Boiler ash	Fly ash	Gypsum and gypsum briquettes
Classification of residues in Germany (Krw-/AbfG)	“important need to be monitored”	“no need to be monitored”		
Quantity [t/a]	12.4	17.7	113.8	15,600
Specific quantity [kg/MWh$_{el}$]	1.08	0.0018	0.0118	1.8
Utilisation / Disposal	Recycling	Mine fill	Mine fill	Gypsum and concrete industry

The emission limit values for sound result from the residential sites which are situated at a distance of 530 – 1,200 m. Measures to reduce sound emissions comprise sound proof security valves and overhead noise barriers. Immission levels at the residential sites reach values between 26 and 46 dB(A).

Economic data

The investment for the flue gas control techniques (wet FGD and SCR) amounted to 256 Mio. EUR in total (between 1990 and 1994).

Driving force for implementation

The retrofitting with wet FGD and SCR resulted from more stringent emission limit values to be complied with. The lining of the stack with GRP was necessary due to complaints about acidic deposits. On the other hand the new material lead to a decrease of stack corrosion and thus reduced operating costs.

2.3.2 Example: Boiler and gas turbine fired with light fuel oil, optional combined-cycle operation

Description

The presented peak load power plant consists of a gas turbine (260 MW$_{th}$ rated thermal input, 60 MW$_{el}$ 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$_{el}$.

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 retrofitted in 1993 for light fuel oil firing. In 1994 the boiler and the gas turbine were both equipped with a water injection system to comply with the NO$_x$ emission level of 150 mg/Nm^3. Additionally, the burner and the combustion chamber of the gas turbine were exchanged. The injection of demineralised water is realised with lances endowed with cone-shaped nozzles at pressures between 3 and 22 bar. The water consumption arises to 50 m^3/h for the boiler and 18.7 m^3/h for the gas turbine at full load operation.

Main 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 aspects

The realised primary measure to reduce NO_x emissions produces no residues nor wastewaters, but it consumes quite big amounts of demineralised water. Furthermore the electrical efficiency of the whole plant is reduced, as the enthalpy, which has to be spent for vaporization, remains in the flue gas and is not re-used.

The treatment of the feed water and the condensate produces sludges and wastewaters.

Operational data

In the year 1998, 6,976 MWh_{el} (gross) were produced by the steam turbine and 118 MWh_{el} (gross) by the gas turbine. The plant was in operation for 74 hours and thus was only used to cover peak loads.

Table 2-84 and Table 2-85 summarise the atmospheric emissions in 1998.

Table 2-84: Atmospheric emissions in of the boiler (single operation) in 1998

	Measurement	ELV (at 3 % O_2)	Measured emission level (daily mean value at 3 % O_2)	Specific emissions [kg/TJ_{fuel}]
O_2-content [%]	continuous		3	
Flue gas volume flow rate [m^3/h]			853,523	
Opacity [Smoke No.]]		1	< 1	
NO_x [mg/Nm^3]	continuous	150	143.3	40.5
CO [mg/Nm^3]	continuous	100	4.77	1.35

Table 2-85: Atmospheric emissions for combined-cycle operation in 1998

	Measurement	ELV (at 3 % O_2)	Measured emission level (daily mean value at 3 % O_2)	Specific emissions [kg/TJ_{fuel}]
O_2-content [%]	continuous		3	
Flue gas volume flow rate [m^3/h]			965,000	
Opacity [Smoke No.]		1	< 1	
NO_x [mg/Nm^3]	continuous	240[1] at full load	259.7	76
CO [mg/Nm^3]	continuous	160[2] at full load	129.8	38

[1] ELV is calculated with the following formula: (mGTx450+mKx150)/(mGT+mK)

[2] ELV is calculated with the following formula: (mGTx300+mKx100)/(mGT+mK)

where mGT: fuel mass flow of gas turbine, mK: fuel mass flow of boiler

In the boiler 2,012,1 tons and in the gas turbine 47.9 tons of light fuel oil were fired.
The once-through cooling system needs about 40,000 m^3/h of water from the adjacent river at full load operation. The effluent of the primary cooling system and the wastewater from the condensate treatment are dumped to the sewer.
the wastewater 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 wastewater are summarized in Table 2-86 for the year 1998.

Table 2-86: Concentrations of impurities in the neutralised wastewater from the feed water treatment in 1998

	Results from individual measurements (1 – 2 in 1998) [mg/l]	ELV [mg/l]
AOX	0.023 - 0.039	1
COD	10 – 23	30 – 80
P	0.12 – 0.2	1.5 – 5
N	42 – 45	10
Zn	0.078	1
Cr	0.0038	0.5
Cd	0.0003	0.05
Cu	0.0044	0.5
Pb	0.0053	0.1
Ni	0.0036	0.5

The main residues are sludges form the water treatment and used lubricants.

Economic data

Total investment for the retrofitting of the plant (water injection, new burner and combustion chamber for the gas turbine) amounted to 12.8 Mio. EUR. The retrofitting of the gas turbine needed a share of 10.25 Mio EUR. The rest was needed for the boiler.

Driving force for implementation

The water injection system was added to comply with emission limit values.

2.3.3 Example: Refinery power plant consisting of two boilers for the valorisation of residues of the conversion of crude oil – SCR and desulphurisation according to the Wellmann- Lord process

Description

This refinery power plant has been started up in 1998 and consists of two boilers (2 x 510 MW_{th}, 2 x 150 MW_{el}, 2 x 620 t/h of steam at 90 bar, 520 °C) for the combustion of residues coming from the High-Soaker-Conversion-plant (HSC-R). In addition to this, also liquid fuels (visbreaker residues, vacuum residues and heavy fuel oil) can be used as substitute fuels. Further on, up to 6 t/h of the heating gas available from the internal net for heating gas can be fired.

The maximum of the gross electrical efficiency is 29.4 %. But this efficiency value is achieved rarely, because of the fact that the main focus is on the production of the steam required by the refinery plants. The maximum of the overall energy efficiency is 73 %.

Besides producing power and steam for the refinery, the plant also delivers power to the local power company and provides part of the energy for the district heating of the nearby city.

The combustion for the oil residues is a frontal combustion and consists of 9 lance shaped atomising burners for each boiler, arranged in three stages,. The burners of the middle stage have additional gas nozzles for the combustion of refinery gas. By the use of low- NO_x burners and a staged feed for combustion air the NO_x concentrations in the flue gas are minimized.

Leaving the boiler the flue gas passes an economizer and a SCR- plant, where the concentration of NO_x is reduced from max. 800 mg/Nm³ to a maximum of 150 mg/Nm³. For this, the plant requires about 145 kg/h of ammonia.

After that, an air preheater is installed, where the flue gas is cooled off before entering the electrostatic precipitator and finally passes the desulphurisation plant, operating according to the Wellman- Lord process. First of all, the flue gas is cooled off in an absorber, then passing three stages of filling bodies. In this part of the plant the SO_2 is absorbed by reacting with a solution of sodium sulphite. The desulphurised flue gas are reheated and dissipate via stack at about 115 °C. The SO_2 containing liquor is pumped to the central regeneration plant, where sulphur is produced. The sulphur plant had to be retrofitted in several parts because of the fact that it was producing sulphur predominantly from H_2S till then. The maximum of the concentration of SO_2 in the purified flue gas is 6,400 mg/Nm³.

Main environmental benefits

This plant provides an energetic valorisation of residues from the refinery with a high overall energy efficiency, because steam as well as heat and power are used in the refinery plant. Further on, the emissions of NO_x, SO_2, SO_3 and particles are reduced effectively.

Applicability

In general, the flue gas cleaning described here is compatible for the retrofitting of all power plants fired with heavy fuel oil. Whether a high-dust arrangement for the SCR- plant, which will reduce the power demand of the whole plant, is possible, must be decided for each case individually.

Cross media aspects

The residues accruing from the flue gas cleaning are:

- Electrostatic precipitator: fly ash
- Desulphurisation plant: elemental sulphur, sulphate containing salts, solid waste from the waste water treatment

Further on, the energy demand of the flue gas cleaning plants reduces the overall energy efficiency.

Operational data

In 2000 the plant operated for 8,760 hours, producing 4,660 GWh_{th} of steam and heat and 1,848 GWh_{el} of power (brutto). The electrical net efficiency was at about 20 %, overall energy efficiency at about 64 %.

The following emissions were measured in 2000:

Table 2-87: Limit values and measured values for atmospheric emissions for all of the three oil- fired boilers in 1999

	Number of measurements per year	Limit value (3% O_2)	Raw gas concentration	Daily mean value based on a concentration of 3 % O_2 in the clean gas	Specific emissions [kg/TJ_{in}]
Content of O_2 in the flue gas	continuous			3.5	
Flue gas volume flow [m^3/h]				781,000	
Dust [mg/Nm^3]	continuous	50	< 1000	11	3.2
SO_2 [mg/Nm^3]	continuous	400	< 6400	363	110
Sulphur emission rate [%]	continuous	15		7.9	
NO_x [mg/Nm^3]	continuous	150	ca. 800	127	36.7
CO [mg/Nm^3]	continuous	175		7	2.0
HCl [mg/Nm^3]	individual	30		15	4.3
HF [mg/Nm^3]	individual	5		0.4	0.1
Ni [mg/Nm^3]	individual			0.02	0.007
V [mg/Nm^3]	individual			0.02	0.007

The diffuse emissions of hydrocarbons out of sealing elements are estimated to be at < 1 kg/h. In the basic year, 580 kt of residues with an mean calorific value of 38.7 MJ/kg and a content of sulphur between 2.6 and 3.1 % were used. Details for the liquid fuels are given in Table 2-88.

Table 2-88: Technical data for liquid fuels

	HSC-R	Visbreaker-residues	Vacuum-residues	Heavy fuel oil
C [mass-%]	87.0 – 87.5	86.5 – 87.0	85.5 – 86.0	85.0
H [mass-%]	8.3 – 8.8	9.3 – 9.8	10,1 – 10.6	11.0
S [mass-%]	2.8 – 3.4	2.7 – 3.4	2.7 – 3.3	3.0
N [mass-%]	0.7 – 1.3	0.6 – 0.9	0.6 – 0.8	0.6
ash [mass-%]	0.1	0.1	0.08	0.1
V [mg/kg]	300 – 410	150 – 260	130 – 220	130 – 190
Ni [mg/kg]	100 – 135	50 – 90	75 – 80	60 – 90
calorific value [MJ/kg]	38.7	39.6	40.0	40.2
density [kg/dm³]	1.06 – 1.07	1.02 – 1.04	1.01 – 1.02	0.955
temperature at the time of being delivered [°C]	260 - 280	195	195	125

The waste water of the plant is unified with the waste water coming from the refinery and is purified with mechanical, chemical and biological processes in the same treatment plant.

Waste water is accruing at the production of demineralised water, the vaporizing and the regeneration of the desulphurisation plant (totalling 75 m³/h). About the pollutant concentrations in these waste water flows no information is available, because of the fact that they are treated together with the waste water incurring at the refinery.

Further on, 160 m³/h of waste water coming from the removal of sludge out of the cooling tower is dumped directly into the preclarifier. The pollutant concentrations of this waste water flow are given in Table 2-89.

Table 2-89: Pollutant concentrations in the untreated waste water of the removal of sludge from the cooling tower

	Limit values [mg/l]	Annual mean value of 6 official measurements [mg/l]	Mass flow per energy input [g/TJ_{input}]
Chlorine	0.2 – 0.3	< 0,3	< 8
AOX	0.15 – 1	0.066	1.65
CSB	30 – 80	35	875
Phosphor	1.5 – 5	0.24	6
Nitrogen	10	37	925
Zinc	1	< 50	< 1,250
Chromium	0.5	< 10	< 250
Cadmium	0.05	< 5	< 125
Copper	0.5	< 10	< 250
Lead	0.1	< 10	< 250
Nickel	0.5	< 10	< 250
Vanadium		< 10	< 250

Residues, mainly ash and gypsum, are accruing in quantities shown in Table 2-90.

Table 2-90: Quantities of waste (in 2000)

Type of waste	Solid salts containing sulphate	Solid waste from the treatment of wash water (containing Ni)	Fly ash containing Ni and V	Spent activated carbon
Classification in Germany (Krw-/AbfG)	“need to be monitored”	„No need to be monitored“	“important need to be monitored”	
Quantity [t/a]	10,330	295	1,180	100
Specific quantity [g/kWh_{el}]				
Utilisation/ disposal	substantial use of sodium sulphate, for the rest: utilisation as mine fill	underground depository	underground depository	incineration

Economic data

The total investment mounted up to 376 Mio. € (1998). The part of the investment for the flue gas cleaning plants amounted to 145 Mio. €. The running costs summed to 12 Mio. € in 2000, including interest payments and disposal costs.

Driving force for implementation

They came to a decision for this plant at the beginning of the nineties, because the former six boilers could no longer meet the ecological requirements. Reasons for the implementation were to realize the denitrification and the desulphurisation according to the legal restraints. The Wellmann- Lord process was chosen, though being comparatively expensive, because the alternative wet desulphurisation process would produce gypsum for which no customer could be found in the surrounding area. Further on it was not sure, that the quality of the gypsum produced would meet the requirements for further processing. High concentration of heavy metals in the gypsum were likely to occur, forcing to deposition of the gypsum.

2.3.4 Example: refinery power plant consisting of four boilers for the valorisation of residues of distillation and conversion processes, SCR and wet scrubber

Description

The refinery power plant described here has been started up in December 1996. It consists of three oil boilers (3* 130 MW_{th}, 3 * 162 t/h steam at 101 bar, 505 °C), which are used for the combustion of visbreaker residues and slurry, and one gas boiler for peak load (1 * 130 MW_{th}, 1 * 155 t/h steam at 100 bar / 505 °C) for the combustion of synthetic gas and heating gas. For auxiliary fuel, REB- residues are burned in the oil boilers and light fuel oil is burned in the gas boiler. Three steam turbines are installed at different pressures respectively with an overall electrical power of 106 MW_{el}. This results in a relatively low gross energy efficiency of 20.4 %, which can be explained however by the special characteristics of the fuels used and the focurs on the use of the steam as process steam.

The power plant provides steam for the refinery at three different stages of pressure (steam at high, middle and low pressure), electrical power at 110 kV, feed water at high and low pressure, process water, service water, cooling water, compressed air and air for the instruments. Besides the refinery, als a separate POX- plant is fed with steam, electrical power and feed water. This plant produces methanol by gasification of highly viscous oils. Depending on the operating status of the plant, parts of the steam can be returned to the power plant.

The firing for the oil residues consists of six atomizing burners for each oil boiler, arranged in pairs at the front in three vertical layers. The combustion is constructed to be able to reach full load with five of the burners. For using visbreaker residues, special operating is necessary. This fuel becomes pumpable only above 150 °C and reaches the properties which are necessary to be atomised in the burner only above 230°C. Therefore this fuel has to be preheated and kept warm at storage.

After leaving the boiler, the flue gas passes a SCR plant. It is the first time, such a high- dust arrangement is used for a combustion of heavy fuel oil. The fuel has relatively high contents of vanadium. While burning, it is oxidised to vanadium pentoxide and is supposed to increase the efficiency of the catalysts. However, this effect could not be proved yet. Further on, the vanadium pentoxide enhances the oxidation from SO_2 to SO_3. A conversion rate of 10 % was estimated, which had great influence on the construction of the wet flue gas cleanings. Because SO_3 occurs mainly as an aerosol, its separation from the flue gas flow via wet scrubber is just contingently possible. Therefore, wet electrostatic precipitators were installed preliminary to the SO_2- wet scrubbers. In order to ensure to put in the flue gas at the right temperature at any time, there is a quencher installed before the electrostatic precipitators. Here, the flue gas is cooled off by injection of water. Also chlorine and fluorine substances are dropped out. After passing the GFK wet scrubber in co- current flow, the clean gas is reheated in a steam-gas- preheater and dissipated via stack.

Main environmental benefits

This plant realizes the energetic valorisation of refinery residues at a high overall energy efficiency by producing steam as well as heat and power, all of them used in the refinery process. Further on, it achieves low emission values for NO_x, SO_2, SO_3 and particles.

Applicability

In general, these flue gas cleaning plants can be retrofitted in any heavy oil fired power plants. The possibility to install the SCR plant in a high-dust arrangement has to be checked for each case individually.

Cross media aspects

The residues accruing from the flue gas cleaning are:

- Wet electrostatic precipitator and quencher: waste water at a very low pH- value (< 1) and contents of heavy metals and sulphate
- Flue gas desulphurisation: waste water, gypsum

Further on, the energetical demand of the flue gas cleaning plants reduces the overall energy efficiency.

Operational data

In 1999, 558 $GWh_{el,netto}$ were produced in about 7,704 operating hours (mean value for all four units). The electrical net efficiency had an annual mean value of about 16 %. Referring to the whole of the plant 6,687 equivalent full load hours were achieved.

In 1999 measurements of atmospheric emissions had the following results:

Table 2-91: Limit values and measured atmospheric emissions of the gas boiler in 1999

		Limit value (3% O_2)		Annual mean value at 3 % O_2	Specific emissions [kg/TJ_{in}]
		for fuel gas / synthetic gas	for extra light fuel oil	for fuel gas / synthetic gas	for extra light fuel oil
Content of O_2 in the flue gas [%]	continuous			3	3
Flue gas volume flow [m^3/h]				130,000	130,000
Dust [mg/Nm^3]	continuous	5	50	0.01	0.0028
SO_2 [mg/Nm^3]	individual	35		< 1.9	< 0.53
NO_x [mg/Nm^3]	continuous	100	150	94	26.1
CO [mg/Nm^3]	continuous	100	100	14.7	4.1

Table 2-92: Limit values and measured atmospheric emissions for the three oil boilers in 1999

	Number of measurements / year	Limit values (3% O_2)	Contents of the raw gas [1]	Annual mean value at 3 % O_2 in the clean gas	Specific emissions [kg/TJ_{fuel}]
Content of O_2 in the flue gas [%]	continuous			3	
Flue gas volume flow [m^3/h]				205,000	
Dust [mg/Nm^3]	continuous	50	220[2] / 400[3]	3.9 – 6.6	1.7 – 2.9
SO_2 [mg/Nm^3]	continuous	400	6,500	133.5 – 158.9	58.5 – 69.9
Sulphur emission rate [%]				4.23	
SO_3 [mg/Nm^3]	individual		650	< 10	
NO_x [mg/Nm^3]	continuous	150	800[4]	114 – 118	49.9 – 51.7
CO [mg/Nm^3]	continuous	175		9.2 – 22.1	4.0 – 9.7
HCl [mg/Nm^3]	individual	30		2.0	0.9
HF [mg/Nm^3]	individual	5		< 0.2	< 0.09
NH_3 [mg/Nm^3]	individual	5			
heavy metals [mg/Nm^3]	individual			0.1 (1998)	0.04

[1] after passing the preheater, unless specified

[2] without soot removing

[3] with soot removing

[4] before DENOX

In the gas boiler, 290 GWh of fuel gas and synthetic gas were used. In the oil boilers 235.5 kt FCC- slurry were burned in total. The quality of this fuel is characterized in Table 2-93. This fuel is very similar to heavy fuel oil. The boilers are also designed for the other fuels mentioned in Table 2-93.

Table 2-93: Characteristics of the FCC- slurry used in 1999

	Visbreaker- residues	FCC-slurry	REB- residues
Calorific value [MJ/kg]	38.7	40.0	39.5
Ash melting point [°C]	> 1,100	> 1,100	> 1,100
Ignition temperature [°C]	> 450	> 300	> 300
Solidifying point [°C]	65	-1	47
Elemental analysis			
Water [mass.-%]	10-7	dry	0.5
Ash [mass.-%]	0.1	0.15	< 0.1
C [mass.-%]	87.3	88	85.3
H [mass.-%]	8.5	9	11.3
S [mass.-%]	< 3.7	< 1.65	< 3.3
N [mass.-%]	0.89	0.19	0.7
O [mass.-%]	0.05		0.04
Cl [mg/kg]	30	< 50	21
Ni [mg/kg]	110	< 200	80
V [mg/kg]	320	300	235

The waste water flows of the four boilers are unified and treated in one plant. The waste water is accruing while regenerating and scavenging the desalination plant and the treatment plant for condensate (about 11.7 m³/h at full load). After being neutralized the waste water has a content of AOX of < 1 mg/l and of 27 mg/l of filterable particles and is dumped into the preclarifier. Further, waste water occurs at the operating of the desulphurisation plant (about 20 m³/h at full load). Attention should be paid to the fact, that the waste water treated in the treatment plant for all waste waters of the flue gas cleaning (German abbreviation "RAA") is not only the weakly acidic waste water of the wet scrubbers but also the strongly acidic water of the quencher and the wet electrostatic precipitator with a pH- value of < 1.

Table 2-94 shows the contents of the treated waste waters (after precipitation, flocculation, sedimentation, sand filter).

Table 2-94: Pollutant concentrations in the treated FDA waste waters

	Limit values [mg/l]	Annual mean value values [mg/l]	Frequency of measurement	Load per fuel energy input [g/TJ_{fuel}]
COD	150	57	daily	3.58E+02
zinc	1	0.09	monthly	5.64E-01
chromium	0.5	0.002	monthly	1.25E-02
cadmium	0.05	0.0001	monthly	6.27E-04
copper	0.5	0.006	monthly	3.76E-02
lead	0.1	0.0001	monthly	6.27E-04
nickel	0.5	0.09	monthly	5.64E-01
filterable material	30	16	daily	1.00E+02
sulfate	2,000	1,565	monthly	9.82E+03
sulfite	20	10	monthly	6.27E+01

fluoride	30	0.1	monthly	6.27E-01
mercury	0.05	0.00001	monthly	6.27E-05
sulfide	0.2	< 0.0001	monthly	6.27E-04

The waste water of the cooling tower (about 440 m³/h at full load) contains the pollutants shown in Table 2-95.

Table 2-95: Pollutant concentrations in the cooling tower waste water

	limit values [mg/l]	annual mean value values [mg/l]	frequency of measurement	load per fuel energy input [g/TJ_{fuel}]
AOX	0.15	0.14	monthly	32.4
COD	150	57	daily	13,288.9
phosphor	3	0.84	monthly	195.6
zinc	1	0.09	monthly	20.9

In addition to this, 1.5 * 10^6 m³ of waste water per year (respectively about 210 m³ at full load) are accruing at the reverse osmosis plant and are dumped without treatment directly into the preclarifier. This is about 67 % of the amount of waste water occurring at the process of reverse osmosis in total. The other third of it is the desalinated water for the water- steam-circuit.

To provide the risk of an accident, there is a precaution waste water plant installed, into which up to 438,000 m³ per year of waste water can be dumped. In the referring year, however, this plant was not needed.

Residues accruing are mainly ashes and gypsum in amounts given in Table 2-96.

Table 2-96: Residues generated in 1998

Type of residues	Sewage of gypsum, coming from the waste water treatment (RAA[a])	FDA gypsum	RAA[a]-substances	KZA[b]-sewage
Classifying[c] according to the German Krw-/AbfG	requiring supervision	not requiring supervision		
Quantity [t/a]	2,810	32,150	5,550	6,800
Amount per input fuel energy [kg/TJ_{fuel}]	222	2,578	442	542
Utilization/ disposal	Disposal	Utilisation	Utilisation	Utilisation

a) RAA: German abbreviation for waste water treatment plant for all waste waters, coming from the flue gas cleanings

b) KZA: German abbreviation for waste water treatment of the cooling tower supplement water

c) under the terms of the German legislation for waste treatment („Kreislaufwirtschafts-/Abfallgesetz“); waste is classified according to its content of pollutants and therefore the treatment required

The legal requirements for noise prevention for the nearby residential quarters, which are situated about 1,000 m from the plant, can be realized by soundproofing, overhead noise barrier and sound absorbers. Therefore, the immissions at place achieve a sound pressure level of between 30 (at night) and 45 dB(A) (during the day).

Economic Data

The total investment for the plant mounted up to 332 Mio. € (1996).

Driving force for the implementation

The denitrification and the desulphurisation plants were implemented in order to fulfil the legal requirements for emission reduction. The concrete design and combination of the processes resulted from the need to reduce the SO_3 emissions of the heavy fuel oil firing. In this situation, the following options were possible:

1) Injection of basic absorbents before a fabric filter, wet scrubber, steam- gas preheater,
2) Heat exchanger for raw flue gas, injection of basic absorbents before a fabric filter, wet scrubber, heat exchanger for clean gas,
3) gas cooling, wet electrostatic precipitator, wet scrubber, steam- gas preheater.

Finally, the last option was chosen because of its low operating costs, though the investment required for the implementation was higher.

2.4 Combustion of gaseous fuels

2.4.1 Example: Gas-fired combined cycle heat and power plant without auxiliary firing

Description

The power plant was erected between 1994 and 1996 with a total capacity of 380 MW_{el} and 340 MW_{th} for power and district heat production (at the design point). It consists of two gas turbines, 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 shows a maximum power output of 185 MW_{el}. The standard fuel is natural gas. Light fuel oil is used as backup 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_{el}. The operation of the whole plant is optimised to cover the heat demand.

Measures for an optimised efficiency

To reach high efficiencies the gas turbines (ABB type GT 13E2) work with a compression ratio of 15:1. The turbine gas temperature amounts to 1100 °C. The whole plant reaches an electrical gross efficiency of 47.4 % (for 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 reached for loads between 60 an 100 %. With a single gas turbine these efficiencies are achieved for loads between 30 and 50 %. At minimum load the efficiency of the gas turbine decreases by 8 % compared to full load operation. The use of heat is optimised by:

- controlled use of exhaust gas heat
- preheating of gas turbine's combustion air at part load
- use of waste heat from transformer

These measures allow for an overall energy efficiency of nearly 90 %. The efficiencies of the whole plant are summarized in Table 2-97.

Table 2-97: Efficiencies of a combined-cycle power plant without auxiliary firing

	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 %

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 from ABB, type EV. NO_x reduction at fuel oil operation is realised by injection of demineralised water. The combustion air can be preheated either to reduce emissions in case of part load operation or in danger of icing. These measures account 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 adjacent residential site is only 16 m away from the building's wall, very low emission limit values must be reached. At the residential site a sound pressure level of 45 dB(A) originating from the power plant can be met due to 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

To avoid emissions of low frequencies the base plates of the gas turbines are beared elastically.

Main environmental benefits

The low-NO_x technique is responsible for comparatively low emissions, taking into account the size of the plant. The measures to use waste heat lead to a high overall energy efficiency and thus do minimise the consumption of resources and the emission of CO_2.

Applicability

The plant was designed to cover a high demand of heat. This is the main prerequisite for a reasonable operation of a plant with 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 with a different design.

Cross media aspects

The primary measures to reduce emissions do not produce any residues. The cooling water and the wastewaters resulting from the operation of the plant are treated on the site. Thereby screenings and sludges are produced.

Operational Data

In 1999 a total of 1,182.2 GWh_{el} of electricity and 1,083.5 GWh of district heating were produced. The 3070 equivalent full load hours result from the demand of district heat. The volume flow rate of the exhaust gas mounts up to 145,0000 m^3/h for a rated thermal input of 470 MW. Table 2-98shows the atmospheric emissions in 1999.

Table 2-98: Emission limit values and measured atmospheric emissions in 1999

	Moni-toring	ELV (15 % O_2)	Daily Mean Values at 15 % O_2		Specific emissions [kg/TJ Input]	
Natural gas – firing			GT 1	GT 2	GT 1	GT 2
Dust [Smoke No.]	continuous	2	0.2	0.2	0.17	0.17
NO_x [mg/Nm^3]	continuous	100	76.0	65.7	62.,65	55.31
CO [mg/Nm^3]	continuous	100	6.7	11.3	5.58	9.48
Fuel oil – firing			GT 1	GT 2	GT 1	GT 2
Dust [Smoke No.]	continuous	2	0.5	0.5	0.66	0.42
NO_x [mg/Nm^3]	continuous	150	79.6	131.4	101.88	112.29
CO [mg/Nm^3]	continuous	100	19.1	13.6	24.44	11.46

In 1999 249.616 · 10^6 Nm^3 of natural gas and 9.463 m^3 of light fuel oil were fired. The consumption of important auxiliary supplies is shown in Table 2-99.

Table 2-99: **Consumption of important auxiliary supplies in 1999**

Auxiliary material	Oils	HCl *(33%)*	NaOH *(50%)*	NaCl-brine	NH_4OH
Application	Turbines / hydraulic systems	wastewater treatment / feed water treatment			
Consumption	1735 litres	72 t	40 t	58 t	300 litres
specific Consumption [g/MWh_{el}]	1,5	61	34	49	0.25

One wastewater flow of the plant originates from the treatment of the feed water and the condensate (12,000 m^3/a). After sedimentation this water is fed into the municipal sewage system. Further wastewaters result from elutriation of the boiler, depletion of the whole system and from condensates (11,014 m^3/a). This wastewater is fed directly to the municipal sewage system after cooling. Wastewater 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 5 years was 0.053 mg/l.

Economic Data

The total investment for the new plant and the demolition of the old coal-fired power station mounted up to 327 Mio. EUR (1997). Detailed repartition of costs is not available.

Driving force for implementation

The former heat and power station on this site could not reach the lower emission limit values from 1996. It also could not be operated in an economically reasonable way anymore. The new plant offered higher efficiencies and a diminished need for manpower 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 of the old plant could not achieve the efficiency of a new one.

2.4.2 Example: Gas-fired combined heat and power turbine for gas and fuel oil firing

Description

This is a example of a combined heat and power station consisting of two gas turbines (2 x 53 MW_{th}, 2 x 18,5 MW_{el}), two waste-heat boilers for long-distance heating (2 x 25 MW_{th}) and four heat exchangers for the production of hot water (4 x 21 MW_{th}) for covering backup and maximum load.

The standard fuel is natural gas whereas light fuel oil is used as backup fuel. The heat and power plant was erected between 1996 and 1997.

Data for the overall energy efficiencies are summarised in Table 2-100.

Table 2-100: Efficiencies of a gas-fired combined heat and power turbine for gas and fuel oil

	Gross efficiency, related to	
	Design point (gas turbines only)	Annual mean value in 1999 (overall efficieny containing also the heat exchangers)
Gross electrical efficiency	34.8 % max. (34,0 % netto)	30 %
Overall energy efficieny	81.6 % max.	72.7 %

NO_x reduction at fuel oil as well as at natural gas firing is realised by injection of demineralised water. For reducing the emissions of CO and hydrocarbons there is a oxidating catalyst installed.

Main environmental benefits

The low-NO_x- technique is responsible for comparatively low emissions, taking into account the size of the plant. The measures to use waste heat lead to a high overall efficieny and thus do minimise the consumption of resources and the emission of CO_2.

Applicability

The plant was designed to cover a high demand of heat. This is the main prerequisite for a reasonable operation of a plant with 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 with a different design.

Cross media aspects

The primary measures to reduce emissions do not produce any residues. The feed water treatment for operating the boiler and the long-distance heating system produces sludges.

Operational Data

In 1999 a total of 118.42 GWh_{el} of electricity and 169.25 GWh of district heating were produced. The 3,200 equivalent full load hours result from the demand of district heat. Table 2-101 shows the atmospheric emissions in 1999:

Table 2-101: Emission limit values and measured atmospheric emissions in 1999

	Monitoring	ELV (at 15% O_2)	Daily mean values[*)] related to 15 % O_2 GT1/GT2	Specific emissions GT1/GT2 [kg/TJ $_{In}$]
Flue gas content of O_2 [%]			15.0/14.8	
Exhaust gas volume rate for 53,2 MW_{th} thermal input			164,000/165,000	
Natural gas - firing				
NO_x [mg/Nm^3]	continuous	150	100/121	86/105
CO [mg/Nm^3]	continuous	100	0.1/0.1	0.086/0.086
Fuel oil - firing				
NO_x [mg/Nm^3]	continuous	200	221/201	190/173
CO [mg/Nm^3]	continuous	100	8.2/7.7	7.06/6.63

[*)] ½-hour mean values, which can be interpreted as daily mean values while operating continuously

35,493·10^3 Nm^3 of natural gas and 198.78 t of light fuel oil were used in 1999. The consumption of important auxiliary supplies is shown in Table 2-102.

Table 2-102: Consumption of important auxiliary supplies in 1999

Auxiliary	Oils	HCl	NaOH	NaCl
Application	Turbines / hydraulic systems	wastewater treatment / feed water treatment		
Consumption per year	1737 l	788 l	1007 l	29.15 t
Specific consumption	14.7 [ml/MWh$_{el}$]	6.7 [ml/MWh$_{el}$]	8.5 [ml/MWh$_{el}$]	246 [g/MWh$_{el}$]

The wastewater flow originates of the wastewater of the chemical water treatment (10,339 m^3/a). It is a discontinuous flow which is fed into the municipal sewage system after having been neutralised.

Economic Data

The total investment mounted up to 36 Mio € (1997). Detailed repartition of costs is not available.

Driving force for implementation

This plant replaced three former heat and power stations which fired heavy fuel oil and raw lignite. These former plants could not fit the ecological demands any longer. As a remediation of them would not have been possible in a economically reasonable way the new plant was implemented.

2.4.3 Example: Combined cycle heat and power plant with auxiliary burners for gas and fuel oil firing

Description

The plant was commissioned in 1995 and consists of three gas turbines with three assigned waste-heat boilers including auxiliary firing, one steam turbine and three condensers for off-take of district heat. The rated thermal input of the plant amounts to 1014 MW with a capacity for combined heat and power production of 480 MW_{th} and 260 MW_{el} (design point).

Each gas turbine has a terminal rating of 63 MW (ISO) at base load and is equipped with a 17-storied compressor and two off-board horizontal combustion chambers.

The standard fuel is natural gas. Light fuel oil is used as backup fuel. The waste heat boilers are equipped with a two-stage auxiliary firing. The first stage produces steam at high pressure (48 - 80 bar / 500 °C) with a maximum thermal power of 43 MW. The second one heats water to 150 °C to feed a separate district heating circuit with a maximum thermal power of 97 MW. The steam turbine is a back-pressure turbine with an output of up to 70 MW_{el}.

The design of the plant was optimised with regard to the security of supply. Thus the following operation modes can be realised:

- waste-heat boiler operation without auxiliary firing;
- bypass of waste-heat boilers: waste-heat boilers are partly bypassed to reach a constant output of electrical power for different heat demands;
- stand-alone operation of the boilers;
- operation with auxiliary firing.

Measures for an optimised efficiency

To reach high efficiencies the gas turbines (Siemens V64.3) work with a pressure ratio of the compressor of 16.1:1. The whole plant reaches an electrical efficiency of 39 % and a thermal efficiency of 47 % at the design point (annual average in 1999).

Primary measures for NO_x emission control

The combustion chambers of the gas turbines are equipped with two-stage low-NO_x-burners. NO_x reduction at fuel oil operation is realised by injection of demineralised water. These measures account for NO_x concentrations of < 100 mg/Nm^3 for natural gas and < 150 mg/Nm^3 for fuel oil.

Measures for reduced emission of sound

As the nearest residential site is only 15 m away from the building's wall, very low emission limit values must be reached. At this residential site a sound pressure level of 43 dB(A) originating from the power plant can be met due to adequate design of facade and roof, acoustic absorbers, soundproof doors and others. To avoid emissions of low frequencies the base plates of the gas turbines and those of pumps are mounted elastically.

Main 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 do minimise the consumption of resources and the emission of CO_2.

Applicability

The plant was designed for a high level of security of supply. That means that in case of failure of one unit the decrease in heat production is not higher than 100 MW. Existing boilers in an old plant might be transformed into a waste-heat boiler. In general retrofitting measures of this kind cannot reach efficiencies of a new plant.

Cross media aspects

The primary measures to reduce emissions do not produce any residues. The feed water treatment for operating the boiler and the long-distance heating system produces sludges.

Operational Data

In 1999 a total of 1526.2 GWh_{el} of electricity and 1981.25 GWh of district heat were produced. The plant was in operation for 7169 hours. The volume flow rate of the exhaust gas mounts up to 1,679,560 m^3/h at an O_2 content of 14.8 %. Table 2-103 shows the atmospheric emissions in 1999.

Table 2-103: Emission limit values and measured atmospheric emissions in 1999

	Monitoring	ELV (at 15% O_2)	Monthly mean value[1] at 15 % O_2	Specific emissions [kg/TJ Input]
Gas turbine with natural gas firing				
Dust [mg/Nm^3]	individual	5	Smoke No. 0.1[2]	0.146
NO_x [mg/Nm^3]	continuous	80	47	36.6
CO [mg/Nm^3]	continuous	50	15	8.93
SO_2 [mg/Nm^3]	calculated	12	0.3	0.06

[1] equivalent to daily mean values at normal operation

[2] mean value of individual results

In 1999 417.929 · 10^6 Nm^3 of natural gas and 492 m^3 of light fuel oil were fired. The consumptions of important auxiliary supplies are shown in Table 2-104.

Table 2-104: Consumption of important auxiliary supplies in 1999

Auxiliary material	Oils	HCl	NaOH	NaOH	NH_4OH
Application	Turbines / hydraulic systems	Wastewater treatment		Feed water treatment / conditioning	
Consumption	2,5 t	57 t	9 t	20 t	0.8 t
Specific consumption [g/MWh_{el}]	1.63	37.3	5.9	13	0.5

The wastewater 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. (16,705 m^3/a). After treatment the wastewater is fed into the municipal sewage system.

Economic Data

The total investment for the plant mounted up to 255 Mio. EUR (1995). The total O&M costs in 1999 were 85.3 Mio EUR.

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 resulted from the heat demand and the possibilities to market the electricity.

The retrofitting of an existing lignite fired heat and power station was not realised for economical reasons.

2.4.4 Example: Boilers in a metallurgical plant, fired with by-product gas, natural gas and light oil for cogeneration of heat and power

Description

The task of the presented CHP-plant is to utilize the gaseous by-products of the smelting process to produce steam and electricity. It consist of two parts. Part A is made of 4 boilers (4 x 250 t/h of steam with 510 °C / 80 bar) which feed the produced steam into 2 steam turbines (200 / 25 MW_{el}) and into the metallurgical plant. Part B consists of one boiler, which is separated from the other four and feeds a 70 MW_{el} steam turbine (265 t/h steam with 530 °C, 180 bar, reheated steam with 530 °C / 40 bar). The total electrical gross power amounts to 295 MW_{el}.

Part A of the plant was equipped with 3 efficient natural circulation boilers at the end of the 80s and early 90s. Even when firing the low-calorific blast furnace gas, a flue gas temperature of 120 °C can be met. The share of the metallurgical gaseous by-products (blast furnace gas, coke oven gas, converter gas) in the total fuel energy mounts up to 97 %. These fuels cannot be burnt as efficiently as natural gas, as they are less calorific, are more “dirty” and are not pressurized when arriving at the power plant.

The produced steam is mainly needed for the metallurgical plant. Furthermore the equivalent of about 10,000 flats and two big factories are supplied with district heat.

Part B of the plant is used to supply the base load as it is more efficient than the other boilers.

The CHP-plant can at any time fire the by-products of the metallurgical plant. Thus the flame losses of the plant are very low (about 0.15 %).

On the other hand this means part load of the CHP-plant under normal conditions.

The NO_x control of the plant comprises Low-NOx-burners and flue gas re-circulation.

Main environmental benefits

The CHP-plant allows for the energetic utilisation of the gaseous by-products of the metallurgical plant. Primary measures reduce the emissions of NO_x.

Applicability

The described plant is adapted to the local conditions as it is integrated into the industrial site.

Cross media aspects

There are no residues resulting from emission control. The treatment of feed water and condensate produces sludges and wastewaters.

Operational Data

In 1998 the plant was in continuously in operation (8760 h) and reached an overall energy efficiency of 45 %.

The atmospheric emissions in this year are shown in Table 2-105.

Table 2-105: Atmospheric emission limit values and emissions in 1998

	Measurement	ELV [mg/Nm^3] at 3 % O$_2$	Measured emission levels	Specific emissions [g/MWh$_{el}$]
Boiler 1 (Part A)				
O$_2$-content [%]	continuous		3.8	
Flue gas volume flow rate [m^3/h]			151,000	
Opacity [Ringelmann-chart]	individual	100	2[2]	0.9
SO$_2$ [mg/Nm^3]	individual	200 – 700[1]	16[2]	7.3
NO$_x$ [mg/Nm^3]	continuous	100 – 150[1]	60	27.4
CO [mg/Nm^3]	continuous	100 – 150[1]	10	4.6
Boiler 2 – 4 (Part A)				
O$_2$-content [%]	continuous		147,500 – 174,400	
Flue gas volume flow rate [m^3/h]			3.5 – 3.8	
Opacity [Smoke No.]	individual	5 – 50[1]	2.1 – 5.4	0.7 – 2.3
SO$_2$ [mg/Nm^3]	individual	35 – 800[1]	2 – 125	0.8 – 46.6
NO$_x$ [mg/Nm^3]	continuous	100 – 150[1]	58 – 60	20.2 – 25.4
CO [mg/Nm^3]	continuous	100 – 150[1]	7 – 9	2.4 – 3.8
Boiler 5 (Part B)				
O$_2$-content [%]	continuous		2.2	
Flue gas volume flow rate [m^3/h]			263,500	
Opacity [Smoke No.]	individual	5 – 50[1]	3[2]	0.95
SO$_2$ [mg/Nm^3]	individual	35 – 700[1]	96[2]	30.0
NO$_x$ [mg/Nm^3]	continuous	100 – 150[1]	93	29.1
CO [mg/Nm^3]	continuous	100 – 175[1]	14	4.4

[1] depending on fuel

[2] mean value of singular measurements

The following fuel quantities were fired in 1998: 52 TJ light oil, 378 TJ natural gas, 6,706 TJ blast furnace gas, 5,575 TJ coke oven gas and 1,790 TJ converter gas.

About 200,000 m^3 of wastewater were released to the central wastewater treatment plant. There is no data available concerning impurities in the wastewater.

Economic Data

There is no data available

Driving force for implementation

The CHP-plant was mainly built to utilise the by-products from the metallurgical plant.

2.4.5 Example: Combined cycle heat and power plant with auxiliary burners for gas and fuel oil firing

Description

As a further example a combined cycle heat and power station commissioned in 1995 with a total rated thermal input of 640 MW_{th} was chosen. It consists of three gas turbines with three assigned waste-heat boilers including auxiliary firing, one boiler and two steam turbines. The boiler serves 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 got a rated thermal input of 135 MW_{th} and a terminal rating of 35.5 MW_{el}. 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, the so called peak load preheaters. Steam is also fed into a net for process steam.

The electrical efficiency in 1998 was 40.2 / 34 % (gross/net) and the overall energy efficiency 59.7 / 45.6 % (gross/net).

Primary measures for NO_x emission control

For the reduction of NO_x an additional system for the injection of steam was installed. The control system injects steam into the combustion chamber with flow rates proportional to the consumption of natural gas. This increases the power and the efficiency of the turbine. On the other hand, less electricity is produced by the steam turbine and thus the electrical efficiency of the whole plant slightly decreases.

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 %).

Operational data

In 1998 a total of 1046 GWh_{el} of electricity and 517 GWh of district heat were produced. 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. Table 2-106 and Table 2-107 define three operational states and lists the related emission limit values and the measured emissions.

Table 2-106: Operation modes of gas turbine and auxiliary firing

Operational state	Rated thermal input of gas turbine [MW]	Rated thermal input of auxiliary firing [MW]	Exhaust gas volume flow rate [Nm^3/h]	Related O_2-Content [%]
I	123	35.6	375,000	13.3
II	119	8.5	360,000	14.5
III	122	0	375,000	15.0

Table 2-107: Emission limit values and measured atmospheric emissions in 1998

Pollutant	Operation mode	Monitoring	ELV [mg/Nm^3]	Daily mean value [mg/Nm^3]	Specific emissions [kg/TJ Input]
NO_x	I	continuous	116	73	56.16
NO_x	II	continuous	104	73	53.91
NO_x	III	continuous	100	82	63.13
CO	I	continuous	100	60	46.12
CO	II	continuous	100	27	19.88
CO	III	continuous	100	9	6.97

In 1998, $265.83 \cdot 10^6$ Nm^3 of natural gas and 480 tons of light fuel oil were fired. The consumption of important auxiliary supplies are shown in Table 2-108.

Table 2-108: Consumption of important auxiliary supplies in 1999

Auxiliary material	Oils	HCl (33%)	NaOH (50%)	$Ca(OH)_2$	$FeCl_3$
Application	Turbines / hydraulic systems	Input water treatment/ Conditioning/ Wastewater treatment			
Consumption	1.4 t	506 t	230 t	69 t	22.2 t
Specific consumption [g/MWh_{el}]	3.4	473	215	64	21

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 sewage systems. One of them for household like sewage, the second one for rain water and water from the boiler, the cooling system, oil separators and settling tanks. This wastewater is dumped to the receiving water course. In 1998, 652471 m^3 cooling water and 117365 m^3 wastewater from the production process were discharged.

Economic Data

The total investment for the plant mounted up to 118 Mio. EUR (1998). The total operational costs in 1998 were 56.1 Mio EUR/a. These can be split up to 16.4 Mio €/a fixed costs and 39.7 Mio. €/a variable costs.

Driving force for implementation

Because of more stringent emission limit values to be complied with, 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 should be extended and the economical performance should be improved. For these reasons the combined cycle power plant was erected. One boiler of the old plant was included into the design of the new plant and was retrofitted to be fired either with natural gas or with light fuel oil.

2.4.6 Example: Natural gas-fired combined cycle power plant without additional firing for the railway power supply system

Description

The selected 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 (2x 180 MW_{th}, 2 x 60 MW_{el}, type V64.3), two waste heat boilers and one steam turbine (57 MW_{el}). In this plant the combination of gas turbines with 16.67 Hz-generators was realised for the first time. The temperature of the hot gas at the turbine intake amounts to 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 economizer and is finally conducted to the chimney with a temperature of 110°C. An additional chimney is installed for each gas turbine for the case of solo 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 were low pressure steam is produced with 198 °C at 4.5 bar. This steam is also conducted to the steam turbine. The reverse-flow cooling system consists of 4 fan driven cellular radiators and the cooling water pump.

The plant was commissioned in 1994 (unit 1) and in 1995 (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 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_{el} are available for solo operation of the gas turbines. The start-up of the waste heat boilers needs between 3 and 6 hours, depending on the precedent time of hold-up.

For combined cycle operation the maximum load-changing speed amounts to 20 MW/min.

NO_x control

The construction of the hybrid burner (diffusion and premixing stage) in combination with an adapted burning chamber ensures low NO_x concentrations far beneath 100 mg/Nm^3. (see operational data)

Main environmental benefits

The realised NO_x control ensures low NO_x emissions. 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 minimise emissions.

Cross media aspects

The cooling tower makeup water is treated in a slow-decarbonisation plant. The incidental sludge mainly contains lime. Furthermore wastewaters and small amounts of residues are produced.

Operational data

In the year 1999 some 501 GWh$_{el}$ of net electricity were produced. The number of equivalent full load hours amounted to 2830.

Table 2-109 shows the atmospheric emissions of the gas turbines in 1999. The flue gas flow rate is 2 x 500,000 m^3/h for full load.

Table 2-109: Emission limit values and measured emission levels in 1999

	Measurement	ELV at 15 % O_2	Measured emission levels	Specific emissions [kg/TJ Input]
Dust [mg/Nm^3]		5		
NO_x [mg/Nm^3]	continuous	100	41.6	32
CO [mg/Nm^3]	continuous	100	1.8	1.4

101.8x10^6 Nm^3 of natural gas (= 0.2 Nm^3/kWh$_{el}$) were fired. The consumption of the most important auxiliary supplies are shown in Table 2-110.

Table 2-110: Consumption of important auxiliary supplies in 1999

Auxiliary material	Lubricants	Ferrous-III-chloride-sulphate	Hydrated calcium lime	Ammonia water	HCl	NaOH	Praestol	Ferrofos
Application		water treatment						
Consumption [t/a]	0.5	60	70	0.5	20	13	1	1
Specific consumption [g/MWh$_{el}$]	1	120	140	1	40	26	2	2

The wastewater flow rate of the whole plant mounts up to 75 m^3/h at full load.
Some 60 m^3/h originate from the cooling system. This wastewater is dumped to the preclarifier without treatment. The wastewaters from the full water softening plant (15 m^3/h) are neutralised and dumped to the preclarifier together with the effluent of the cooling system. The concentrations of impurities in the this mixed wastewater is shown in Table 2-111 for the year 1999. Partly the legal limit values are not met. This results from the initial level of pollution before the water enters the power plant.

Table 2-111: Concentrations of impurities in the wastewater of the power plant

	Mean value from 14 measurements (if not specified) [mg/l]	Limit values [mg/l]	Specific load [g/MWh$_{el}$]
Cl	339	0.2 – 0.3	137
AOX	0.06	1	0.024
COD	67	30 – 80	27.1
P	17.5	1.5 – 5	7.07
N	8	10	3.23
Zn	< 50*	1	-*
Cr	< 2*	0.5	-*
Cd	< 0.1*	0.05	-*
Cu	< 5*	0.5	-*
Pb	< 3*	0.1	-*
Ni	< 5*	0.5	-*
Filterable matter	8.7	50	3.52
Sulfate	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

The only source for a considerable amount of residues is the cooling tower makeup water treatment where sludges are produced. In 1999, 214.4 tons of these sludges had to be dumped in a landfill and 50.3 tons were used for spreading in agriculture. Furthermore, 10 tons of used detergent from turbine cleansing, 6 tons of residues from the oil separator, 12 tons of municipal waste and 12 tons of paper 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 reached in this distant.

Economic data

The total investment amounted to 185 Mio. EUR (1995). This equals a specific investment of 1,043 EUR/kW_{el}.

Driving force for implementation

The restructuring of the railway in the new Federal States after 1989 evoked the necessity of a new power plant with the following characteristics:

- extremely short time for the erection of the plant
- high efficiency
- low environmental burden
- low investment and operational costs

The realised plant meets these requirements from the operator's viewpoint.

2.4.7 Example: Combined cycle heat and power plant with auxiliary burners for gas and fuel oil firing

Description

The plant was commissioned in 1994 to 1996 and consists of two gas turbines (2 x 67.8 MW_{el}) with two assigned waste-heat boilers (2 x 26.5 MW_{th}) including auxiliary firing and one steam turbine (48.8 MW_{el}).

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 fuel oil operation is realised by injection of demineralised water.

Main 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 do minimise the consumption of resources and the 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 cannot reach efficiencies of a new plant.

Cross media aspects

The primary measures to reduce emissions do not produce any residues. The treatment of input water produces sludges.

Operational Data

In 1999 a total of 530 GWh_{el} 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 flow rate of the exhaust gas mounts up to 2 x 526000 m^3/h at an O_2 content of 14.5 %. Table 2-112 shows the atmospheric emissions in 1999.

Table 2-112: Emission limit values and measured atmospheric emissions in 1999

	Monitoring	ELV (at 15% O_2)	Monthly mean value[1)] at 15 % O_2	Specific emissions [kg/TJ fuel]
Gas turbine with natural gas firing				
NO_x [mg/Nm^3]	continuous	max. 85[2)]	60	46.7
CO [mg/Nm^3]	continuous	max. 40[2)]	6	3.6

[1)] equivalent to annual mean value for rated load

[2)] The ELV is not constant but depends on ratio of FUEL $INPUT_{Gas\ turbine}$: FUEL $INPUT_{WHB}$

In 1999 132 · 10^6 Nm^3 of natural gas (equivalent to 43.9 MJ/kWh_{el}) and 181 m^3 of light fuel oil were fired.

The wastewater 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/a). The main source is the regeneration of the ion exchangers. Wastewater 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 tons of oil and oil contaminated materials were recycled and 1.6 tons of filter material were disposed of.

As the adjacent residential site is only 110 to 300 meters away from the single components of the plant, extensive sound reduction measures had to be realised. These comprise acoustic insulation of the boiler and the ducts, sound absorbers and encapsulation of loud 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 resulted from the heat demand and the possibilities to market the electricity.

2.4.8 Emerging Technologies: Gas-steam turbine power plant without auxiliary firing but with primary NO_x- reduction

Description

This power plant is planned to have three generating units, setup with a single axle configuration. Each of the units will be equipped with a gas turbine and a waste-heat boiler. Technical data are summarized in Table 2-113. The start-up of the power plant is supposed to be in 2003.

Table 2-113: Technical data for the operation at the design point and at an annual mean temperature of 8 °C

	Unit	Design point
Rated thermal input	MW	3 x 700
Input of natural gas	Nm^3/h	3 x 65.825
Gross energy output	MW	
Net energy output	MW_{el}	3x 407
Net efficiency	%	58
Flue gas temperature	°C	105

The main benefit of this power plant is the high electrical net efficiency, which is supposed to reach up to 58 %. The following measures provide this high efficiency:

- gas turbine, steam turbine and generator are setup with a single-axle configuration
- gas turbine with high efficiency (38 % at an annual mean temperature of 8 °C)

The dry- low- NO_x- method is used as a primary reduction method for NO_x emissions in the gas turbines while operating with gas at normal condition. For the same purpose, steam is injected while operating with light fuel oil.

In order to avoid diffuse emissions of the handling of NH_3-, hydrazine- and $HCl_{(g)}$, adsorbers are used.

The submitted limit values for atmospheric emissions are shown in Table 2-114.

Table 2-114: Submitted limit values for atmospheric emissions at 15 % O_2

Type of fuel	Dust [mg/Nm^3]	NO_x [mg/Nm^3]	CO [mg/Nm^3]
Natural gas	2	80	100
Extra light fuel oil	50	150	100

Main environmental benefit

The main benefit of this power plant is its high efficiency rate. Atmospheric emissions are reduced by primary and secondary measures and all limit values can be guaranteed. However, exact data for the emissions cannot be given yet.

Applicability

In general, technologies described here can be used for any new construction of hard coal power plants with pulverised fuel firing. But it will still have to stand the test while operating.

Operational Data

Of the operational data planned, only data for the wastewater flow and amounts of waste is given yet. While operating at full load, a wastewater flow of 40 m³/h will occur at the treatment of the cooling water, the desalination of the boiler and the purification of the compressor of the gas turbine. In addition to this, 90,000 m^3/h of cooling water pass the once-through cooling flow path. Other waste is produced in small amounts only (Table 2-115).

Table 2-115: Estimated quantities of waste

Classification in Germany (Krw-/AbfG)	Type of waste	Quantity [t/a]	Specific quantity [g/MWh_{el}]
"important need to be monitored"	washing liquor for the compressor	60	6.7
	waste oil	25	2.8
"need to be monitored"	filter mats	60	6.7
„No need to be monitored"	ion exchangers	2	0.2

Economic Data

There are no data of investment or costs available yet.

Driving force for implementation

The high efficiency rate is supposed to ensure an operating in an economical reasonable way. The site at the sea provides the possibility of an efficient once-through-cooling. In addition to this, the infrastructure of the closed nuclear power plant (tubes for the cooling water flow, electrical switch and control gears) can be used.

2.5 Techniques for co-combustion

2.5.1 Example: Co-combustion of sewage sludge in a lignite-fired circulating fluidised bed combustion plant with mercury emission control

Description

The presented CFBC-boiler has a rated thermal input of 275 MW and mainly produces steam for a lignite processing plant. After first tests of 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 nozzle lignite coke dust (produced in open-hearth process) into the flue gas. After 20 meters, 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 is separated in the existing ESP together with the particulate matter.
The share of sewage sludge in the total rated thermal input can be up to 4 %.

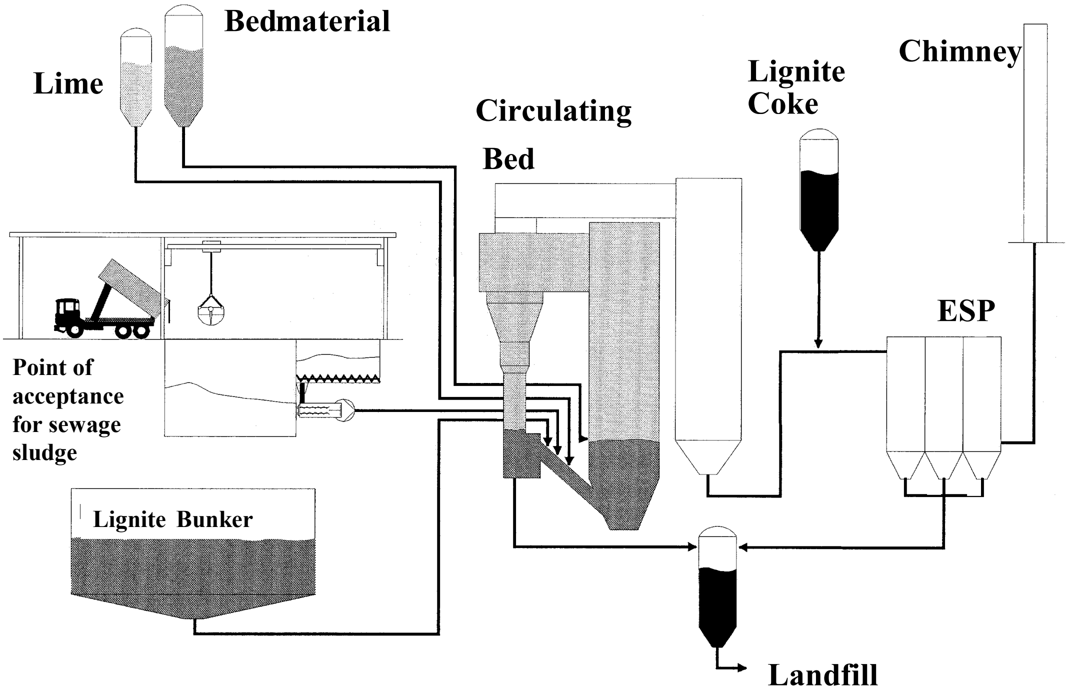

Figure 2-9: Schematic set-up of the lignite-fired CFBC-boiler with co-combustion, modified from [1]

Main achieved environmental benefits

The energetic use of sewage sludge reduces the consumption of lignite. Thus, consumption of resources and emissions of CO_2 are reduced. The mercury emission control reduces the atmospheric mercury emissions by up to 85 %. The resulting emissions are far below the legal emission limit values.

Applicability

The co-combustion of sewage sludge in CFB-plants has shown to be technically viable if the share in the rated thermal input does not exceed 5 %. The atmospheric emissions either do not change (SO_2, NO_x) or only do increase marginally (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.

Nozzling in of lignite coke, like it was realised in the described plant, is a well known control technique in waste incinerators to reduce heavy metals, dioxins and furans. The only restriction of this process is the temperature, as 170 °C 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 to 2.7 mg/kg due to the loaded coke.

Operational data

The concentration of mercury in the flue gas for co-combustion of sewage sludge without emission control amounted to about 0.025 mg/Nm^3. The injection of lignite coke with a rate of 80 kg/h reduced the emissions by 75 to 85 % to about 0.004 mg/Nm^3. Nearly the same separation efficiency could be reached with an injection rate of 50 kg/h, whereupon this value was reached only two hours after beginning of 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 2-116.

Table 2-116: Characteristics of the lignite and the sewage sludge

	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

The leachability of the fly ash does not change due to the addition of lignite coke. Thus the heavy metals keep fixed in the lignite coke.

Economic data

Full costs for the co-combustion of sewage sludge amount to about 100 €/t (1997).

The operators of sewage plants pay about 50 €/t sewage sludge for combustion. About 50 €/t is the value of the produced steam.

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 the one of an entrained flow reactor as the installation is more simple and no additional fabric filter is needed. The operational costs should be in the same range, as the main costs are related to the consumption of lignite coke (about 150 €/t of coke in 1994). This means about 0.045 €/MWh$_{fuel}$ for the presented plant.

Driving force for implementation

The motivation for co-combustion was 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.

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2.5.2 Example: Co-combustion of sewage sludge in a pulverised hard coal fired Dry Bottom Boiler

Description

The presented unit has a rated thermal input of 1933 MW and a gross electrical power of 760 MW$_{el}$. Co-combustion of thermally dried sewage sludge was tested in 1996 and since 1998 the operator is authorised to fire thermally as well as mechanically dried sewage sludge. The maximum allowed share of dry matter (DM) of sewage sludge in the total mass input of the boiler amounts to 4 %. This results in an annual co-combustion potential of 40,000 tons DM$_{sewage\ sludge}$ (dry matter of sewage sludge) which is the equivalent production of about 1.82 million inhabitants.

The thermally dried sewage sludge with a dry matter content of 85 % is stored in a 20 m^3-silo from where it is transported to the 600 m^3-coal bunker which stores the fuel of 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 flexible than the 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 the 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, no problems with the boiler like corrosion were encountered due to the co-combustion. The staff received anti-hepatitis vaccination and has to wear special overalls and protective masks when working near sewage sludge storage or transportation.

Main achieved environmental benefits

The co-combustion of sewage sludge reduces the coal input and thus reduces the emissions of 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 might lead to a negative balance, resulting in a net increase of CO_2.

As can be estimated from [4], the savings of coal for a sewage sludge with a mean DM-content of 57 % (as assumed for this plant), amount to about 5800 MJ/t dry matter$_{\text{sewage sludge}}$. Furthermore, toxic organic substances, like 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 successfully been applied in several pulverised coal boilers as well as in fluidised bed combustion plants. From the 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 the one of sewage sludge.

Cross media effects

The atmospheric emissions of volatile heavy metals like arsenic, selenium and especially mercury might increase due to the co-combustion of sewage sludge. For the presented plant, the change of emissions is shown in Table 2-117. 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 atmosphere.

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 recovery of the by-products (fly ash, boiler ash, gypsum) can be maintained.

As the ash content of sewage sludge is higher than the one 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 a first testing period, the atmospheric emissions for co-combustion of sewage sludges from different regions were measured and compared to the singular combustion of hard coal. The results are presented in Table 2-117. The share of the sewage sludge in the mass input into the boiler ranged between 2.2 and 4.7 %.

Table 2-117: Atmospheric emission for co-combustion of sewage sludges and singular combustion of hard coal during testing period of 10 weeks in 1996

	ELV for singular hard coal firing [mg/Nm^3]	ELV for co-combustion [mg/Nm^3]	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	150	149	3 – 10	4.7 – 8.5
SO_2	400	396	80 – 270	175 – 270
NO_x	200	201	150 – 190	170 – 180
Particulate matter	50	50	5 – 20	4.6 – 6.1
HF	10	9,9	1 – 3.4	1.5 – 2.5
HCl	90	89	0.6 – 7	0.7 – 2.3
organic carbon	-	10	1.0	0.3 – 1.3
Σ Cd,Tl	-	0.05	< 0.005 [1]	< 0.005
Hg	-	0.05	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	-	0.5	< 0.075	< 0.075
dioxins/furans	-	0.1 ng TE/Nm^3	< 5 pg TE/Nm^3	3.3 – 4.8 pg TE/Nm^3

[1] singular measurement in September 1996

[2] given as 2-hour-mean-value; only concentration in gas-phase is given as concentration in particulate matter was too low for measurement

For these measurements, sewage sludges from five different regions were used. The elementary analysis of sewage sludges from two of these sewage plants is shown in Table 2-118, whereas the concentration of impurities in the sludges from all five sewage plants is given in Table 2-119.

Table 2-118: Elementary analysis of sewage sludges from two sewage plants

	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 2-119: Range of concentration of impurities in the sewage sludge from the different sewage plants during testing period

	Limit value for co-combustion [mg/kg DM]	Concentration in sewage sludge 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

No relevant concentrations of dioxins/furans was measured in any of the by-products (ash, gypsum, wastewater). The increase of heavy metal contents in the by-products was insignificant and the quality of the by-products virtually did not change. Thus the boiler ash, the fly ash and the gypsum can be 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. About 55% of the mercury is also captured in this way. The remaining 45 % are emitted into the atmosphere.

Economic data

There are no specific data available for the presented plant. In [4], the full costs for the co-combustion of sewage sludge with 30/92.5 % dry mass are estimated to 52/46 €/t respectively.

Driving force for implementation

The operators of sewage plants had to look for new ways to recover the produced sewage sludge, as new legislation does not permit the disposal any more from 2005 on and farmers more and more refuse to use the sludge as fertilizer. These developments allow for an economically efficient way of co-combustion for the operator of the power plant.

References

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2.5.3 Example: Co-combustion of biomass in a power plant fired with pulverised black lignite

Description

The presented power plant consisted of three units until 1999, when two of them were shut down. In 1996, the co-combustion of mouldings made from different biomass sources was tested in several experiments for unit B. Unit B was shut down in 1999. In 1998, co-combustion of waste wood was tested in unit D and was carried out on a regular basis from June 1999 on.

The results of both co-combustion experiments are presented here.

Co-combustion of mouldings in unit B

Unit B has a rated thermal input of 280 MW and gross power output of 108 MW_{el}. Black lignite is fired and thus a DeNOx plant, realised with SCR-technique in high-dust configuration, is necessary next to primary measures. Furthermore, an ESP and a wet FGD are installed. For co-combustion, no additional installations were required. The mouldings were mixed with the lignite at the campground, which produced quite high emissions of dust.

The mouldings were cylindrically-shaped, had a diameter of about 25 mm and were made from three different biomass sources:

- A: straw
- B: cereal plants
- C: pasture from landscape cultivation

Four experiments were carried out on weekends, each for a 24 hours time period with mouldings of one type. Additionally, co-combustion of mouldings from straw was tested in a three-weeks 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 D

Unit D has a rated thermal input of 803 MW and a gross power output of 316 MW_{el}. The configuration of the emission control is identical to the one of unit B. The wood chips are fed into the coal bunkers where they mix with the lignite. As the wood chips are virtually not grinded in the coal mills, they fall down onto the afterglow grate where they partly burn in a floating bed. The big, unburnt 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 2-120). Especially waste wood treated with halogenated finish or with wood preservatives containing heavy metals must not be fired. Since June 1999, about 300 – 350 tons of waste wood chips are fired every day, representing about 12 % of the mass input and 8 % of the thermal input.

Main environmental benefits

Co-combustion of biomass safes fossil resources and reduces emissions of CO_2. The co-combustion of wood chips in unit D reduces the consumption of black lignite by approximately 80 000 tons per year.

Applicability

As the co-combustion of biomass is not yet a standard process, no general guidelines concerning the applicability can be derived.

Operational data

Co-combustion of mouldings in unit B

The average composition of the 4 fuels used for the co-combustion experiments are displayed in Table 2-120.

Table 2-120: Average composition of the 4 fuels used for the co-combustion experiments

	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

The function of the coal mills was tested for biomass portions ranging from 10 to 40 %. More than 40 % biomass could not be handled by the mills. Table 2-121 shows the resulting size-distribution of the fuel after grinding in the coal mills. It can be seen that for a 10 % - portion of biomass, the distribution changes only slightly, where as for higher portions, the share of the very fine particles (< 0.09 mm) strongly decreases. This means, that it is not only the biomass, that is grinded badly but the grinding of the coal is also deteriorated by high shares of biomass.

Table 2-121: Quality of milled fuels for different portions 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 % moulding A	7	27	16	48
27.5 % moulding A	19	36	14	31
19.2 % moulding B	23	35	16	26
20.0 % moulding C	22	43	15	20

Increased slagging occurred only during the 3-weeks co-combustion of straw mouldings. The SCR and the ESP were not influenced. The atmospheric emissions for the five different tests are shown in Table 2-122.

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 the ones 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 TE/Nm^3)

Table 2-122: Atmospheric emissions: Comparing the five different co-combustion tests and singular coal firing

	Unit	Coal only	Co-combustion of mouldings from...				
			straw	straw	cereal plants	pasture from landscape cultivation	straw (3-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	3800
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

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 D

Here, the results of the test, which took place in 1998, are presented. During 370 hours of operation, about 5400 tons 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 2-123.

Table 2-123: Characteristics of the coal and the wood chips and the maximum allowed concentrations of impurities in the wood chips

	unit	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

The atmospheric emissions during co-combustion in 1999 and the imposed ELV are put together in Table 2-124.

Table 2-124: Measured emission values and ELV for co-combustion of waste wood chips

	Unit	ELV at 7 % O_2	Mean value from 3 singular measurements in 1999 at 7 % O_2
Dust	mg/Nm^3	40	8
CO	mg/Nm^3	200	35
NO_2	mg/Nm^3	200	117
SO_2	mg/Nm^3	310	103
total carbon	mg/Nm^3	6	2.3
HCl	mg/Nm^3	25	1.1
HF	mg/Nm^3	10	< 0.1
Cd, Tl	mg/Nm^3	0.02	0.001
Hg	mg/Nm^3	0.009	0.002
PCDD/PCDF	ng TE/Nm^3	0.027	0.0025

The emissions of metals and dioxins/furans did not change due to co-combustion.

Economic data

The specific costs (€/MJ) for the biomass mouldings are about 4 times higher than for coal. The investment for the upgrading for the co-combustion of wood chips amounted to 0.7 Mio €. The costs for the handling of the wood chips and the logistics inside the power plant amount to approximately 8 – 10 €/t.

Driving force for implementation

Co-combustion of biomass mouldings was only tested but was not realised on a regular basis. Co-combustion of waste wood chips was realised, as the additional payment for the co-combustion and the savings in coal allow for an economical operation.

References

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2.5.4 Example: 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 at a wet bottom boiler to evaluate the effects of co-combustion of thermally dried sewage sludge. The power plant consists of two boilers. The bigger one with a rated thermal input of 382 MW was used for the experiments.

The plant is equipped with a SCR in high-dust configuration, followed by the air preheater and the 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.

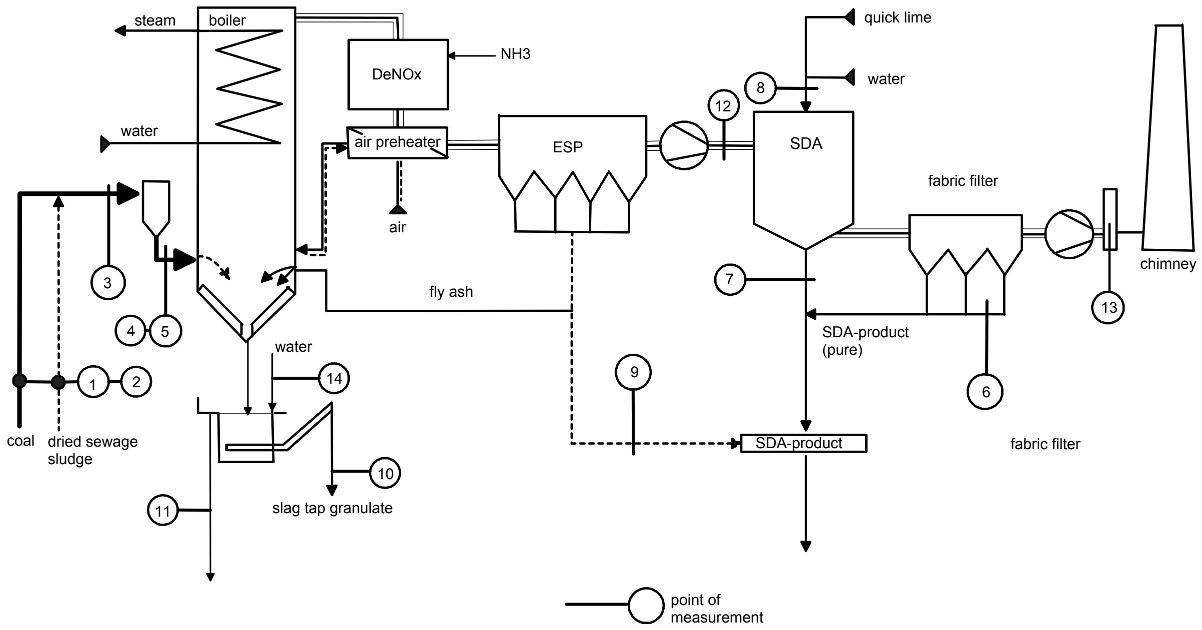

Figure 2-10: Schematic set-up of the WBB with co-combustion of sewage sludge and the sampling points (modified from [1])

Main environmental benefits

The co-combustion of sewage sludge reduces the coal input and thus reduces the emissions of 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 might lead to a negative balance, resulting in a net increase of 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 the 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 the one of sewage sludge. Thus, co-combustion is often limited in these cases to sewage sludge with a dry mass content of more than 90 %, like it is done in the presented plant.

Operational data

In 1996, co-combustion took place for three days. During this time, the share of sewage sludge with a water content of 10 % in the total mass input amounted to 12.5 %, the share in the power input amounted to 5 %. To compare the measurements for co-combustion, the same measurements were carried out for three days for hard coal only. Figure 2-10 shows the sampling points.

All in all, 371 tons of sewage sludge from 7 different sewage plants were fired. The mean quality of the sewage sludge and the fired coal is shown in Table 2-125.

Table 2-125: Mean composition of hard coal and sewage sludge before and during co-combustion

		Hard coal	Hard coal	Sewage sludge	Limit values for use of sewage sludge for co-combustion
	Unit	singular combustion of hard coal	co-combustion	co-combustion	
Calorific 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	mg/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

The resulting concentrations of impurities in the flue gas with and without co-combustion are shown in Table 2-126 for two different sampling points, one upstream the FGD, the other downstream the fabric filter.

Table 2-126: Concentrations of impurities in the flue gas with and without co-combustion

	Unit	Mean values of 3-days-period measurements at 5 % O_2				ELV in 17. BImSchV at 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	0.1
PCB	ng/m^3	-		9.8	8.25	
C_{total}	mg/m^3	-		0.4	0.6	10
Benzene	mg/m^3	-		< 0.003	< 0.003	5
HCl	mg/m^3	-		4.5	4.5	10
HF	mg/m^3	-		< 0.02	< 0.02	1
Dust	mg/m^3	19.9	13.2	1.5	1	10
Hg	mg/m^3	0.0093	0.01296	0.00814	0.00861	0.05
Cd	mg/m^3	0.00034	0.00037	< 0.00001	< 0.00001	0.025
Tl	mg/m^3	0.00008	0.00002	< 0.00003	< 0.00003	0.025
As	mg/m^3	0.02494	0.01704	0.00006	< 0.00003	0.05
Pb	mg/m^3	0.02716	0.02520	0.00003	0.00003	0.05
Cu	mg/m^3	0.01330	0.01429	0.00043	0.00023	0.05
Zn	mg/m^3	0.04252	0.05758	0.00215	0.0014	-
Mn	mg/m^3	0.02191	0.01296	0.00201	0.00138	0.05
Ni	mg/m^3	0.00802	0.00479	0.00033	0.00015	0.05
Co	mg/m^3	0.00382	0.00216	0.00005	0.00003	0.05
V	mg/m^3	0.02337	0.00954	0.00137	0.00076	0.05
Cr	mg/m^3	0.00986	0.01117	0.00068	0.00031	0.05
Sb	mg/m^3	0.00097	0.00114	0.00002	< 0.00003	0.05
Sn	mg/m^3	< 0.00002	0.00007	< 0.00002	< 0.00002	0.05
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	10
NO_x	mg/m^3	-	-	185	185	200
CO	mg/m^3	-	-	17.0	12.7	50

The following main findings for the fate of metals result from these measurements:

- The only increase in the atmospheric emissions occurs for mercury (about 6 %), whereupon this increase is not significant as the accuracy of metrology is not sufficient.

- The element Cr solely enriches in the slag tap granulate.
- The elements Pb, Ni and Hg mainly can be found in the fly ash and the SDA product.
- The elements Cd, Cu and Zn enrich in both sinks.

Table 2-127: Composition of residues with and without co-combustion

	Unit	Slag tap granulate		Mix of by-products: fly ash (30 %) and product of SDA (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	mg/kg	-	-	0.02	0.02
PCDD/PCDF	mg/kg	-	-	0.001	0.003

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 PCB due to co-combustion does not lead to increasing atmospheric emissions of these substances. They both are destroyed in the boiler at high temperatures of about 1500 °C. The de novo synthesis can be excluded, as the flue gas is abruptly cooled down to 130 °C in the air preheater and as the S/Cl-ratio amounts to 7/1.

The dried sewage sludge was quite easy to handle. Problems occurred while adding it to the coal conveyor band, as dust was formed. In general, the experience showed that dried sewage sludge should be stored and transported only in closed systems.

Economic data

As co-combustion was only realised for a testing period, no economic data is available.

Driving force for implementation

The operators of sewage plants had to look for new ways to recover the produced sewage sludge, as new legislation does not permit the disposal any more from 2005 on and farmers more and more refuse to use the sludge as fertilizer. In general, these developments allow for an economically efficient way of co-combustion for the operator of the power plant.

For the presented plant, the co-combustion was not realised as the regulatory authority demanded additional measures to reduce the atmospheric emissions of mercury. The usual way to do that (injection of coke or activated coke) would have been too expensive and it would have impaired the quality of the product of the SDA.

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2.5.5 Emerging technology: Pyrolyis upstream a coal-fired boiler for co-combustion of secondary fuels

The so-called Contherm plant was developed to allow for 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 burnt 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.

Up to 120,000 t/a of RDF will be fired, resulting in a rated thermal input into the coal boiler of up to 75 MW_{th}. The RDF will consist of sheared plastic waste from different sources, industrial waste and coarse reject from paper industry. The size of the waste chips must not exceed 200 mm. About 7,900 t/a of recyclable metals will be extracted in the reprocessing plant.

The power plant is equipped with a SCR and a wet FGD.

The schematic set-up of the pyrolysis plant and the connection with the coal-fired boiler shows Figure 2-11.

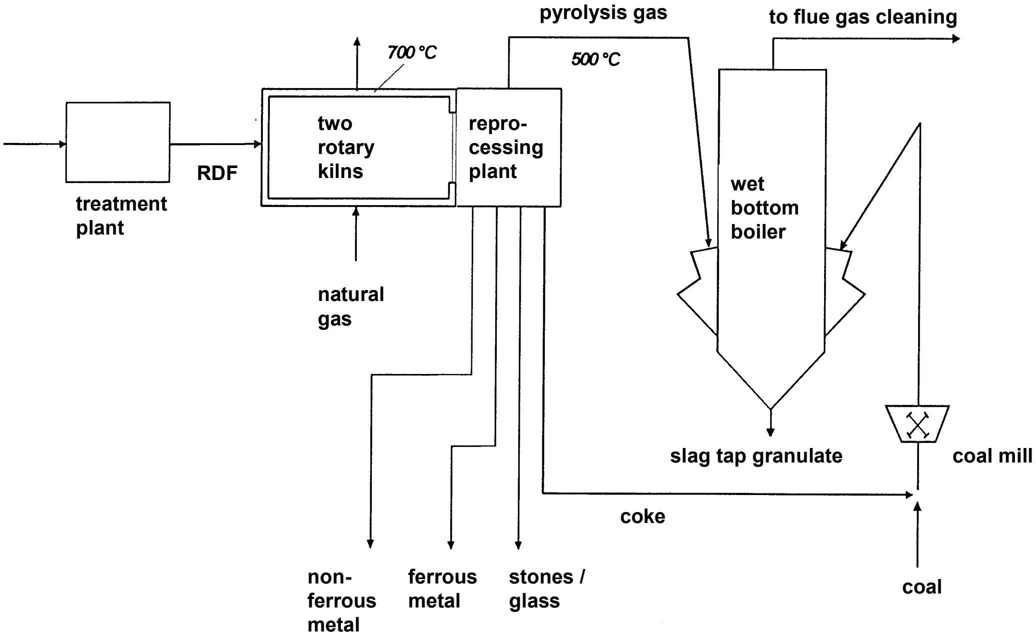

Figure 2-11: Schematic set-up of the pyrolysis plant, [1] (modified)

Reference

[1] Hauk, R.: *Verbrennung von Ersatzbrennstoffen in Kraftwerken*, VDI-Seminar vom 15. – 16.02.2001 in Neuss

3 Best available techniques (BAT) for the combustion of coal and lignite

The BAT for the combustion of coal and lignite can be divided into five groups:

I. Techniques for handling, transportation and storage of coal and additives
II. Techniques used in the water-steam-cycle and the cooling system
III. Combustion techniques and measures to reduce atmospheric emissions (primary and secondary measures) and production of waste
IV. Co-generation of heat and power
V. Techniques to treat and minimise waste waters

This division into five groups is reasonable, as these groups are quite independent from another, which means that, for example, techniques to store and transport coal can usually be combined with any combustion technique.

3.1 Major items associated with BAT concerning handling, transportation and storage of coal and additives

The environmental key issues for these process steps are fugitive emissions and health and safety aspects. The main features are:

Process step	**BAT**	**Environmental benefit**
Coal storage	Open stockpiles: spraying with water, wind protection walls	Reduction of fine dust particle emissions
	Enclosed storage, large capacity silos with air suction at the transfer points and subsequent fabric filters	Low fine particulate emission small use of land;
Transport, loading and unloading of coal	Closed transport systems, transport systems with air suction or sprinkler systems at the transfer points, open belt conveyor equipped with lateral wind protection, enclosed or tube belt conveyor, pneumatic conveyor; reduced emissions grabs, screw conveyors, loading pipe with height adjustment with or without loading head, cascade chute	Reduction of fine particulate emission
Transport and storage of additives	Enclosed storage of lime or limestone, large capacity silos with air suction at the transfer points and subsequent fabric filters; transport pneumatically; distribution of gases by pipelines; storage of liquids in drums or tanks with surface protection	Low fine particulate emission; assuring health and security standards (esp. for toxic substances like NH_3)

3.2 Major issues associated with BAT for the water-steam-cycle and the cooling system

Main environmental issues of these process steps comprise the consumption of resources (affected by the efficiency), the emission of heat and substances to watercourses and the consumption of auxiliary supplies (chemicals for conditioning of water-steam-cycle and the cooling cycle). The measures to improve the environmental performance comprise those, which are used in newly built plants and those, which can be applied to existing plants for retrofitting.

Process step	**Remarks**	**BAT**	**Environmental benefits/trade-offs**
Superheating of steam (techniques to reach high steam parameters)	new, large PP	Usage of most advanced materials allows for steam pressures of 300 bars and steam temperatures of 600 °C; these parameters can only be achieved with a Benson-type boiler.	These steam parameters result in high overall electrical efficiencies; in combination with once-through seawater-cooling, hard coal-fired power plants reach up to e = 48 %, lignite-fired plants up to 45 % (under construction, in combination with natural draught cooling-tower)
Cooling system	-	The highest efficiencies can be reached with cooling systems which allow for the lowest pressures in the condenser (< 30 mbar possible!). If only this aspect is taken into account, the following ranking of cooling techniques can be derived: 1) once-through cooling system (seawater or river water) 2) natural draught wet cooling tower 3) hybrid cooling tower 4) mechanical draught wet cooling tower 5) air cooling system	The ranking is only based on the overall efficiency and must be modified by site-specific conditions as some major benefits or threats to the local environment might occur (for more details, the BREF on Industrial Cooling Systems should be consulted): 1) this technique often strongly deteriorates the aqueous eco-systems due to the immission of heat 2) high demand of land and water; shadows 3) smaller than 2) and needs less water, produces virtually no clouds 4) smaller than 2) 5) no water is needed => advantage in arid regions
Cooling system makeup-water treatment	-	(see BREF on Industrial Cooling Systems)	

Process step	Remarks	BAT	Environmental benefits/trade-offs
Treatment of water for water-steam circuit	-	Reverse osmosis should be used for demineralisation; if this technique alone is not sufficient it can be combined with ion exchangers.	Reverse osmosis allows for smaller loads of salt in the waste water of the treatment system than ion exchangers (40 – 50 % reduction);
	-	Ion exchangers should work in counter flow operation	Counter flow operation of ion exchangers reduces demand for chemicals and water;
	-	When decarbonisation is carried out with lime, the sludge should be re-used (cement industry, wet FGD, agriculture)	Reduction of waste disposal
	-	Conditioning of water: "combined operation": small amounts of ammonia are added (0.1-0.15 g/m^3) together with addition of oxygen (0.05-0.3 g/m^3)	Reduction of nitrogen in the waste water from water-steam-circuit
Steam turbine	new/retro-fitting	Optimised turbine blades and improved in- and outlet lead to efficiencies of 91 – 96 %	High efficiency
Regenerative feed water heating	new large PP	High number of stages for regenerative feed water heating increases unit efficiency; new plants use up to 10 stages, resulting in a feed water temperature of about 300 °C or more.	High efficiency
Reheating	new large PP	High unit efficiencies are achieved with a double reheat stage	High efficiency

3.3 Major issues associated with BAT for combustion techniques and measures to reduce atmospheric emissions

General techniques

Process step	BAT	Environmental benefits/trade-offs
Emission path of flue gas to the atmosphere	Flue gases should be emitted via the cooling tower if one is used	Reheating of flue gas after the FGD-plant is not necessary resulting in rise of efficiency; no stack is needed
	In case of emission via a stack, 70 – 80 °C are sufficient values for the temperature of the flue gas	Reheating can be reduced, resulting in rise of efficiency; cladding inside the stack necessary to prevent corrosion due to condensing acid (SO_3)
	The energy in the flue gas should be used as much as possible: in a new lignite plant, the flue gas is cooled down to 100 °C in the economiser and air preheaters before it enters the wet FGD.	In this example, the efficiency rises by 1.2 %-points compared to conventional technique in a lignite plant; trade-off: condensation of acid components and thus potential corrosion

Process step	BAT	Environmental benefits/trade-offs
	For reheating of flue gas upstream a SCR plant or downstream a FGD, a heat displacement system should be used	Advantages compared to a gas-gas heat exchanger: less HCl/HF-formation
Boiler	Efficiency up to 93 % for lignite and up to 95 % for hard coal	Rise of efficiency
	Excess air ratio should be minimised (1.15-1.25)	Rise of efficiency
SCR	Separation efficiencies for NO_x range between 85 and 90 %, the NH_3 slip should not exceed 2 mg/Nm^3 (measured in the stack)	Reduction of NO_x-emissions and limited emission of NH_3
	The SCR plant should be installed in high-dust-configuration	Reheating of flue gas is not necessary like in low-dust or tail-end-configuration; this results in rise of efficiency. Trade-off like corrosion of catalyser in high-dust-configuration might occur for wet bottom boilers
	Catalysers should be regenerated if they have lost too much of their effectiveness instead of being renewed (two methods are described in this document)	Saving of heavy metal-containing materials and cost reduction
	Storage of ammonia as an aqueous solution, especially if residential sites are in the vicinity of the plant	Safety aspects: if stored as liquid ammonia, the residents might be endangered if the ammonia is set free in case of emergency
FGD	The FGD can be operated with separation efficiencies well above 95 %,	Reduction of SO_2-emissions
	All residues can be used (e.g. in gypsum industry, building material industry) and do not have to be disposed of.	Reduction of waste disposal
Own electricity demand	Energetic optimisation of fans, coal mills and wet FGD	Rise of efficiency
Drying of lignite	The most efficient way to dry lignite is the use of heat with low temperatures, for example the waste heat of the flue gases	This technique was realised in a pilot-plant and promises a rise of efficiency of 3 to 5 percentage points!

3.4 Major issues associated with BAT for co-generation of heat and power

The co-generation of heat and power should be a task for any newly built power plant. One major prerequisite is the local demand for heat. As this is often the limiting factor, the size of those CHP plants which are in the scope of the IPPC Directive mostly ranges between 50 and 300 MW_{th}. Furthermore, demand for heat often varies strongly throughout the year. This means, that especially CHP plants should be very flexible concerning the ratio of produced heat to electricity and they should posses high efficiencies also for small loads. If only a small amount of heat is needed (e.g. in summer for district heating), it should be possible to rise the electrical efficiency to operate the plant as an efficient power producer. An example for a technique which is suitable to fulfil these tasks is compound operation of a coal-fired boiler with a gas turbine.

This flexibility plays an important role in cases with fluctuating demand. like district heating. For other fields, like in certain industrial applications, the heat demand is nearly constant throughout the year and thus the CHP plant can be optimised for a certain heat to power ratio.

As the overall efficiency in a specific case strongly depends on the demand curve for heat during the year, the appropriate technique must be derived individually.

3.5 Major issues associated with BAT to treat and minimise waste waters

Emission limit values and thus treatment techniques are often site-specific as the receiving eco-systems have different sensitivities concerning the immissions of certain substances. The following list contains the techniques considered to be BAT for the single sources of waste water.

Source of waste water	BAT concerning treatment and minimisation of waste water flows	Environmental benefits/trade-offs
Cooling Water	Usually does not to have to be treated before it is discharged. Exemptions might result from intense conditioning of the cooling water with microbiocides, anti-corrosion substances, water softener or with dispersing agents. Treatment might also be necessary if water from closed cooling systems or water resulting from cleaning of the cooling system is discharged. (see also BREF on Industrial Cooling Systems)	
Waste water from desulphurisation plant (wet FGD)	Should be treated in several process steps: removal of fluoride (floccluation, sedimentation), removal of heavy metals (flocculation, sedimentation, filtration), removal of COD (ion-exchange) and finally pH-adjustment (neutralisation).	
	If ammonia content is too high (e.g. due to SCR/SNCR upstream the FGD), additional reduction measures should be applied (possible techniques: air stripping, precipitation as magnesium-ammonium-phosphate, biodegradation).	
	Waste waters can be minimised by closed-loop operation of the desulphurisation plant. The resulting specific discharge can be about 0.005 – 0.01 m^3/MWh_{th}, whereas this value also depends on the coal properties.	Reduction of waste water
	The mechanically dewatered sludge (mainly gypsum) resulting from sedimentation should be used internally, if possible (e.g. re-use in FGD, addition to coal); it can also be used as filling material for mining industry	Minimised waste
	After treatment, the waste water still has high contents of salts ($CaCl_2$, $MgCl_2$, $MgSO_4$); these concentrations can be toxic to soft water organisms; thus, the cleaned waste water should either be discharged together with waste water from other sources with low salt concentrations (e.g. cooling water) to decrease the salt content of the mix. If this is not possible, the waste water can also be evaporated, whereas the resulting salts are highly leachable and must be disposed of.	Protection of soft water organisms
	The wet FGD can be operated without any emission of wastewater by mixing the wastewater with the coal ash to form a stabilised material that can be used as filling material in open cast mines as it has a very low leachability for heavy metals.	Reduction of waste water
Waste water from slag flushing and ash transport	**Closed water circuit**: solids are only taken from the circuit as ash sludge (DBB) or slag tap granulate (WBB). The water remains in the circuit and is cooled by a secondary circuit via heat exchangers.	Minimised water consumption and no emission of dissolved particles
	If no closed water circuit is applied, the dissolved particles in the waste water should be separated (sedimentation or filtration) and the temperature of discharged water should be controlled as it might be too high for aqueous environment;	Minimise emission of dissolved particles and heat into the aqueous environment
Waste waters from regeneration of demineralisers and	Reverse osmosis: 15 – 50 % of the amount of produced demineralised water is discharged as waste water, which contains the ingredients of the input water in higher concentrations. This waste water does not have to be treated. Waste water from washing of reverse osmosis system might need treatment before discharge.	

Source of waste water	**BAT concerning treatment and minimisation of waste water flows**	**Environmental benefits/trade-offs**
condensate polishers	Waste waters from regeneration and washing of ion exchangers for full water softening or decarbonisation: neutralisation, subsequent sedimentation; the resulting sludge should be dewatered and disposed of.	Prevent emission of acid or alkaline waters, dissolved salts and resin particles
Waste water from elutriation	If water-steam-system is operated with neutral water, no treatment is necessary before discharge; if alkaline operation is applied, the elutriated water should be neutralised; if the concentration of hydrazine is too high, the waste water should be oxidised in a chemical treatment step. High concentrations of phosphate might also result in additional treatment.	
Waste water from washing of boilers, air preheater and ash precipitator	Water should be collected and neutralised; further treatment is usually necessary, e.g. in the FGD waste water treatment plant; NH_3 concentration can also be reduced by stripping ; if possible, wet cleansing should be replaced by dry cleansing; the washing process should be realised with closed water loops, i.e. the treated water should be re-used for washing	Reduction of waste water
Waste water from boiler acid washing	This step is usually done only once, before the first operation of the boiler; the produced waste waters must be treated with neutralisation and sedimentation the resulting sludge should be dewatered and disposed of	
Surface run-off water included water from fuel storage area	Use of surface run-off water after treatment (sedimentation, maybe chemical treatment) for internal processes	Reduction of waste water

3.6 Comparison of emission levels of candidate BAT installations to the requirements of the European Directive 2001/80/EC

As for some techniques, the emission limit values depend on the size of the plant, the following size classes are defined, which are based on the classification scheme of the LCP-Directive:
I: 50 – 100 MW_{th}
II: 100 – 300 MW_{th}
III: 300 – 500 MW_{th}
IV: > 500 MW_{th}

Emission levels associated with Best Available Techniques (BAT) for the combustion of solid fuels:

Abbreviations:

PC	pulverised coal	CP	Combined processes
DBB	Dry bottom boiler	AC	Activated Carbon
WBB	Wet bottom boiler	SER	Sulphur emission rate
FBC	Fluidised bed combustion		
		SCR	Selective catalytic reduction
FGD	Flue gas desulphurisation	SNCR	Selective non-catalytic reduction
ws	Lime/limestone wet scrubbing	LNB	Low NOx Burner
ds	Dry sorption	ESP	Electrostatic precipitator
sd	Spray dryer	FF	Fabric filter
		CC GT	Combined Cycle Gas Turbine

am	annual mean
mm	monthly mean
dm	daily mean

According to Directive 2001/80/EC sulphur emission rates overrule SO_2 limit values only if concentrations in flue gases cannot be met due to fuel characteristics.

3.6.1 Sulphur dioxide emissions

Category	**Size class**	**Fuel type**	**Boiler type**	**Primary emission control**	**Secondary emission control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
New plant	IV	Coal	all			6	EC : 200 (dm) or 400 + SER ≤ 5 %	
Existing plant[1)], retrofitted	IV	Coal	all			6	EC: 400 (mm)	
	IV 733 MW$_{th}$	Hard coal	PC, DBB		FGD (ws) η: 96 – 98,5 %	6	D: 100 (dm)	20 (am, 99% of dm < 60)
	IV 1820 MW$_{th}$	Hard coal	PC, DBB	S content 0.7 – 0.9 %	FGD (ws) η > 85 %	6	D: 400 (dm) SER 15 %	150 (am) SER 10 %
	IV 1370 MW$_{th}$	Hard coal	PC, DBB		FGD (ws) η > 95 %	6	D: 200 (dm)	52 (am)
	IV 1278 MW$_{th}$	Hard coal	PC, DBB	S content 1.09 %	FGD (ws)	6	D: 400 (dm) SER 15 %	254 (am) SER 8.6 %
	IV 1892 MW$_{th}$	Hard coal	PC, WBB	S content 0.8 – 1 %	FGD (ws) η: 92 - 95 %	5	D: 400 (dm) SER 15 %	185 (am) SER 11.4 %
	IV 800 MW$_{el}$	Brown coal	PC, DBB	S content 0.5-1.4	FGD (ws) η > 98 %	6	D: 400 (dm) SER 5 %	66 (am) SER 1.7 %
	IV 800 MW$_{el}$	Brown coal	PC, DBB	S content 0.5-1.4	FGD (ws) η > 98 %	6	D: 400 (dm) SER 5 %	70 (am) SER 1.8 %
	IV 2400 MW$_{th}$	Brown coal	PC, DBB	S content 1.91	FGD (ws) η > 98 %	6	D: 400 (dm) SER 5 %	291 (mm) SER 3 %
	IV 2400 MW$_{th}$	Brown coal	PC, DBB	S content 1.91	FGD (ws) η > 98 %	6	D: 400 (dm) SER 5 %	297 (mm) SER 2.9 %
	IV 1243 MW$_{th}$	Brown coal	PC, DBB		FGD (ws) 94.6 %	6	D: 400 (dm) SER 15 %	211 (dm) SER 2.9 %
	IV 6x500 MW$_{el}$	Brown coal	PC, DBB	S content 0.5 - 1.4	FGD (ws)	6	D: 400 (dm) SER 5 %	140 - 200 (am) SER 2.7 - 5 %

Category	**Size class**	**Fuel type**	**Boiler type**	**Primary emission control**	**Secondary emission control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
New plant	III	Coal	all			6	EC: 200 (dm) or 400 + SER ≤ 5 %	
Existing plant[1)], retrofitted	III	Coal	all			6	EC: ca. 1300 - 400 linear (mm) + SER ≤ 10%	
	III 356 MW$_{th}$	Brown coal	PC, DBB		AC filter	6	D: 400 (dm) SER 10 %	5 (dm) SER < 1 %
	III 398 MW$_{th}$	Hard coal	PC, WBB	S content 1.1 %	FGD (ws)	5	D: 400 (dm) SER 15 %	201 (am)
New plant	II	Coal	all			6	EC : 200 (dm) or 400 + max. 5 % SER	
Existing plant[1)], retrofitted	II	Coal	all			6	EC: 2000 – ca 1300 linear (mm) + SER ≤ 25%	
	II 278 MW$_{th}$	Brown coal	PC, DBB		AC filter	6	D: 400 (dm) SER 10 %	5 (dm) SER < 1 %
	II 183 MW$_{th}$	Hard coal	PC, WBB		FGD (sd)	5	D: 250 (dm) SER 10 %	75.5 (am)
	II 119 MW$_{th}$	Brown coal	AFBC	S content 1.7	Lime addition	7	D: 400 (dm) SER 15 %	393 (am) SER 9 %
New plant	I	Coal	all			6	EC: 850 (dm) + SER ≤ 8 %	
Existing plant[1)], retrofitted	I	Coal	all			6	EC: 2000 (mm) + SER ≤ 40 %	
	I 92 MW$_{th}$	Hard coal	PC, DBB		DESONOX η: 85 %	6	D: 270 (dm)	128 (am)
	I 94 MW$_{th}$	Hard coal	PC, DBB		DESONOX η: 85 %	6	D: 270 (dm)	53 (am)
	I 78.8 MW$_{th}$	Brown coal	AFBC	S content < 0.8	Lime addition	7	D: 500 (dm)	241 (dm, range 200 - 300)
New plant	I	Bio-mass	all			6	EC: 200 (dm)	
Existing plant[1)], retrofitted	I	Bio-mass	all			6	EC: 2000 (mm) + SER ≤ 40 %	
	I 90.5 MW$_{th}$	Wood	AFBC			7	D: 165 (dm)	29 (am)

1) Existing installations are subject to national reduction plans which shall ensure an emission reduction equivalent to the limit values given in the table.

3.6.2 Nitrogen dioxide emissions

Category	**Size class**	**Fuel type**	**Boiler type**	**Primary emission control**	**Secondary emission control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
New plant	IV	Coal	all			6	EC : 200 (dm)	
Existing plant[1], retrofitted	IV	Coal	all			6	EC: 500 (mm), 200 (starting in 2016)	
	IV 733 MW_{th}	Hard coal	PC, DBB	LNB	SCR	6	D: 130 (dm)	90 (am, 99% of dm < 130)
	IV 1820 MW_{th}	Hard coal	PC, DBB	Air staging; LNB	SCR	6	D: 200 (dm)	190 (am)
	IV 1370 MW_{th}	Hard coal	PC, DBB	LNB	SCR	6	D: 200 (dm)	167 (am)
	IV 1278 MW_{th}	Hard coal	PC, DBB	LNB, flue gas recirculation	SCR	6	D: 200 (dm)	192 (am)
	IV 1892 MW_{th}	Hard coal	PC, WBB	-	SCR	5	D: 200 (dm)	200 (am)
	IV 800 MW_{el}	Brown coal	PC, DBB	Fuel + air staging	-	6	D: 200 (dm)	145 (am)
	IV 800 MW_{el}	Brown coal	PC, DBB	Fuel + air staging	-	6	D: 200 (dm)	141 (am)
	IV 2400 MW_{th}	Brown coal	PC, DBB	Air staging	-	6	D: 200 (dm)	121 (mm)
	IV 2400 MW_{th}	Brown coal	PC, DBB	Air staging	-	6	D: 200 (dm)	125 (mm)
	IV 1243 MW_{th}	Brown coal	PC, DBB	LNB, Air staging	-	6	D: 200 (dm)	149 (dm)
	IV 6x500 MW_{el}	Brown coal	PC, DBB	Fuel + air staging, flue gas recircul.	-	6	D: 200 (dm)	164 - 188 (am)

Category	**Size class**	**Fuel type**	**Boiler type**	**Primary emission control**	**Secondary emission control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
New plant	III	Coal	all			6	EC: 200 (dm)	
Existing plant$^{1)}$, retrofitted	III	Coal	all			6	EC: 600 (mm)	
	III 398 MW$_{th}$	Hard coal	PC, WBB		SCR	5	D: 200 (dm)	180 (am)
New plant	II	Coal	all	air and fuel staging, LNB, reburning	SCR; SNCR or CP	6	EC: 300 (dm)	
Existing plant$^{1)}$, retrofitted	II	Coal	all	air and fuel staging, LNB, reburning	SCR; SNCR or CP	6	EC: 600 (mm)	
	II 278 MW$_{th}$	Brown coal	PC, DBB	LNB, Fuel + air staging	AC filter	6	D: 200 (dm)	120 – 135 (dm)
	II 183 MW$_{th}$	Hard coal	PC, WBB	Air staging	SCR	5	D: 400 (dm)	323 (am)
	II 119 MW$_{th}$	Brown coal	AFBC	Air staging	-	7	D: 200 (dm)	168 (am)
New plant	I	Coal	all	air and fuel staging, LNB, reburning	SCR; SNCR or CP	6	EC: 400 (dm)	
Existing plant$^{1)}$, retrofitted	I	Coal	all	air and fuel staging, LNB, reburning	SCR; SNCR or CP	6	EC: 600 (mm)	
	I 92 MW$_{th}$	Hard coal	PC, DBB		DESONOX	6	D: 200 (dm)	158 (am)
	I 94 MW$_{th}$	Hard coal	PC, DBB		DESONOX	6	D: 200 (dm)	155 (am)
	I 78.8 MW$_{th}$	Brown coal	AFBC	Fuel + air staging, flue gas recircul.	-	7	D: 400 (dm)	272 (dm, range 240 - 360)
New plant	I	Bio-mass	all			6	EC: 400 (dm)	
Existing plant$^{1)}$, retrofitted	I	Bio-mass l	all			6	EC: 600 (mm)	
	I 90.5 MW$_{th}$	Wood	AFBC	Air staging, flue gas recirculation	-	7	D: 350 (dm)	164 (am) 339 (am)
	I 73.5 MW$_{th}$	Wood	Grate firing	Air staging	-	11	D: 200 (dm)	184 – 191 (dm)

1) Existing installations are subject to national reduction plans which shall ensure an emission reduction equivalent to the limit values given in the table.

3.6.3 Dust emissions

Category	**Size class**	**Fuel type**	**Boiler type**	**Primary emission control**	**Secondary emission control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
New plant	IV	Coal	all			6	EC : 30 (dm)	
Existing plant[1)], retrofitted	IV	Coal	all			6	EC: 50 (mm)	
	IV 733 MW_{th}	Hard coal	PC, DBB		ESP, FGD	6	D: 20 (dm)	5 (am, 99% of dm <8)
	IV 1820 MW_{th}	Hard coal	PC, DBB		ESP, FGD	6	D: 100 (dm)	< 10 (am)
	IV 1370 MW_{th}	Hard coal	PC, DBB		ESP, FGD	6	D: 20 (dm)	3 (am)
	IV 1278 MW_{th}	Hard coal	PC, DBB		ESP, FGD	6	D: 50 (dm)	7 (am)
	IV 1892 MW_{th}	Hard coal	PC, WBB		ESP, FGD	5	D: 50 (dm)	5 – 10
	IV 800 MW_{el}	Brown coal	PC, DBB		ESP, FGD	6	D: 50 (dm)	2 (am)
	IV 800 MW_{el}	Brown coal	PC, DBB		ESP, FGD	6	D: 50 (dm)	3 (am)
	IV 2400 MW_{th}	Brown coal	PC, DBB		ESP, FGD	6	D: 20 (dm)	2 (am)
	IV 2400 MW_{th}	Brown coal	PC, DBB		ESP, FGD	6	D: 20 (dm)	2 (am)
	IV 1243 MW_{th}	Brown coal	PC, DBB		ESP, FGD	6	D: 50 (dm)	14 (dm)
	IV 6x500 MW_{el}	Brown coal	PC, DBB		ESP, FGD	6	D: 50 (dm) (upstream FGD)	3 (am) (downstr. FGD)
New plant	III	Coal	all			6	EC: 30 (dm)	

Category	**Size class**	**Fuel type**	**Boiler type**	**Primary emission control**	**Secondary emission control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
Existing plant[1)], retrofitted	III	Coal	all			6	EC: 100 (mm)	
	III 398 MW$_{th}$	Hard coal	PC, WBB		ESP	5	D: 50 (dm)	11 (am)
New plant	II	Coal	all			6	EC : 30 (dm)	
Existing plant[1)], retrofitted	II	Coal	all			6	EC: 100 (mm)	
	II 278 MW$_{th}$	Brown coal	PC, DBB		ESP, AC filter	6	D: 80 (dm)	25-30 (dm)
	II 183 MW$_{th}$	Hard coal	PC, WBB		ESP, FGD	5	D: 65 (dm)	15 (am)
	II 119 MW$_{th}$	Brown coal	AFBC		ESP	7	D: 25 (dm)	10 (am)
New plant	I	Coal	all			6	EC: 50 (dm)	
Existing plant[1)], retrofitted	I	Coal	all			6	EC: 100 (mm)	
	I 92 MW$_{th}$	Hard coal	PC, DBB		ÊSP, DESONOX	6	D: 20 (dm)	n.a.
	I 94 MW$_{th}$	Hard coal	PC, DBB		ÊSP, DESONOX	6	D: 20 (dm)	n.a.
	I 78.8 MW$_{th}$	Brown coal	AFBC		FF	7	D: 50 (dm)	7 (dm, range: 5 – 35)
New plant	I	Bio-mass	all			6	EC: 50 (dm)	
Existing plant[1)], retrofitted	I	Bio-mass	all		ESP, FF	6	EC: 100 (mm)	
	I 90.5 MW$_{th}$	Wood	AFBC		FF	7	D: 17 (dm)	2 – 4 (am)
	I 73.5 MW$_{th}$	Wood	Grate firing		FF	11	D: 10 (dm)	3 – 4 (dm)

1) Existing installations are subject to national reduction plans which shall ensure an emission reduction equivalent to the limit values given in the table.

3.6.4 Other pollutants

Size class	**Fuel type**	**Boiler type**	**O_2 content [%]**	**CO ELV [mg/m^3]** (statistics)	**CO [mg/m^3]** (statistics)	**HCl / HF ELV [mg/m^3]**	**HCl / HF [mg/m^3]**	**N_2O [mg/m^3]**
IV 733 MW$_{th}$	Hard coal	PC, DBB	6	100 (dm)	16 (am)	20 / 2	2 / 0.2	-
IV 1820 MW$_{th}$	Hard coal	PC, DBB	6	250 (dm)	12 (am)	100 / 15	< 30 / < 3	-
IV 1370 MW$_{th}$	Hard coal	PC, DBB	6	200 (dm)	23 (am)	20 / 2	< 1.73 / < 0.2	-
IV 1278 MW$_{th}$	Hard coal	PC, DBB	6	200 (dm)	17 (am)	-	-	-
IV 1892 MW$_{th}$	Hard coal	PC, WBB	5	250 (dm)	27 (am)	100 / 15	3-11 / 3-10	-
IV 800 MW$_{el}$	Brown coal	PC, DBB	6	250 (dm)	57 (am)	7.5 / 2.5	0.4 / 0.1	-
IV 800 MW$_{el}$	Brown coal	PC, DBB	6	250 (dm)	57 (am)	7.5 / 2.5	0.4 / 0.1	-
IV 2400 MW$_{th}$	Brown coal	PC, DBB	6	250 (dm)	8 (am)	15 / 5	-	-
IV 2400 MW$_{th}$	Brown coal	PC, DBB	6	250 (dm)	26 (am)	15 / 5	-	-
IV 1243 MW$_{th}$	Brown coal	PC, DBB	6	250 (dm)	4 (dm)	-	-	-
IV 6x500MW$_{el}$	Brown coal	PC, DBB	6	250 (dm)	164 – 200 (am)	30 / 5	< 1 / < 1	-
III 398 MW$_{th}$	Hard coal	PC, WBB	5	250 (dm)	25 (am)	-	-	-
II	Hard coal	AFBC	7	250 (dm)	55 (dm, range: 30 – 70)	165 / 22	164 / 21	
II 278 MW$_{th}$	Brown coal	PC, DBB	6	250 (dm)	< 80 (dm)	30 / 10	< 0.2 / 1	-
II 183 MW$_{th}$	Hard coal	PC, WBB	5	175 (dm)	6 (am)	20 / 3	0.7 / 0.05	-
II 119 MW$_{th}$	Brown coal	AFBC	7	250 (dm)	0.2 (am)	150 / 10	4 / 0.5	26 (am)
I 92 MW$_{th}$	Hard coal	PC, DBB	6	250 (dm)	18 (dm)	100 / 15	- / < 10	-
I 94 MW$_{th}$	Hard coal	PC, DBB	6	250 (dm)	31 (dm)	100 / 15	- / < 10	-

Size class	**Fuel type**	**Boiler type**	**O_2 content [%]**	**CO ELV [mg/m^3]** (statistics)	**CO [mg/m^3]** (statistics)	**HCl / HF ELV [mg/m^3]**	**HCl / HF [mg/m^3]**	**N_2O [mg/m^3]**
I 78.8 MW_{th}	Brown coal	AFBC	7	250 (dm)	9 (dm, range 0 – 50)	50 / 3	0.4 – 6.8 / 0.7 – 1.3	-
I 90.5 MW_{th}	Wood	AFBC	7	200 (dm)	147 (am) 178 (am)	25 / 1.7	7 / 0.04 9 / 0.1	-
I 73.5 MW_{th}	Wood	Grate firing	11	80 (dm)	46.7 – 58.3	10 / -	8 / -	-

3.6.5 Trace pollutants

Size class	**Fuel type**	**Boiler type**	**O_2 content [%]**	Σ Heavy Metals [mg/Nm^3]	Individual elements [mg/Nm^3]	Hg [mg/Nm^3]	Dioxins/ Furans [ng TE/m^3]	Other organic pollutants [mg/Nm^3]
IV 1933 MW_{th}	Hard coal	PC, DBB	6	Σ Sb, As, Pb, Cr, Co, Cu, Mn, Ni, V, Sn: < 0.075	Σ Cd,Tl: < 0.005	0.0003 – 0.012	< 0.005	Total org. C: 1.0
IV 1933 MW_{th}	Hard coal + sewage sludge	PC, DBB	6	Σ Sb, As, Pb, Cr, Co, Cu, Mn, Ni, V, Sn: < 0.075	Σ Cd,Tl: < 0.005	0.0001 – 0.013	0.0033 – 0.0048	Total org. C: 0.3 – 1.3
IV 803 MW_{th}	Black lignite + waste wood	PC, DBB	7	Σ Cd,Tl 0.001		0.002	0.0025	Total C: 2.3
III 382 MW_{th}	Hard coal	PC, WBB	5		As: 0.00006 Pb: 0.00003 Cu: 0.00043 Zn: 0.00215 Mn: 0.00201 Ni: 0.00033 Co: 0.00005 V. 0.00137 Cr : 0.00068 Sb : 0.00002	0.00814	0.00861	Total C: 0.4

Size class	**Fuel type**	**Boiler type**	**O_2 content [%]**	Σ Heavy Metals [mg/Nm^3]	Individual elements [mg/Nm^3]	Hg [mg/Nm^3]	Dioxins/ Furans [ng TE/m^3]	Other organic pollutants [mg/Nm^3]
III 382 MW_{th}	Hard coal + sewage sludge	PC, WBB	5		Pb: 0.00003 Cu: 0.00023 Zn: 0.0014 Mn: 0.00138 Ni: 0.00015 Co: 0.00003 V. 0.00076 Cr : 0.00031	0.00861	< 0.001	Total C: 0.6
II 275 MW_{th}	Brown coal + sewage sludge	CFBC + coke injection	7			0.004 (unabated: 0.025)		
II 278 MW_{th}	Brown coal	PC, DBB	6		Pb: 0.005 Cu: 0.007 Mn: 0.003 V: 0.002 Se: 0.004 Sn: 0.004	< limit of detection: < 0.0005	< limit of detection: < 0.001	Total C: < limit of detection: < 2
I 90.5 MW_{th} 2 Unit	Wood	AFBC Unit I Unit II	7	 0.015 0.006	Σ Cd,Ti 0.004 0.003	 0.001 0.001	 0.013 0.006	Total org. C 2.0 2.0
I 73.5 MW_{th}	Wood	Grate firing	11	As/Pb/Cu/ Ni/Sn(in dust) 0.053	Cd: 0.0005	0.001	0.0019	Total org. C 1.1 – 1.2 PAH: 0.0003

(Pollutant concentrations are determined by individual measurements)

4 Best available techniques (BAT) for the combustion of biomass

4.1 Major items associated with BAT for techniques for processing and storage of wood fuels (peat and straw are not addressed)

The environmental key issues for these process steps are to prevent impurities and pollutants from getting into the combustion chamber and thus reduce the emissions of the following combustion step. The main features are:

Process step	**BAT**	**Environmental benefit**
Wood processing	Wood processing with several steps to sort out impurities, remove metal components; classifying according to the chip size, content of pollutants; closed system with air suction at the transfer points and subsequent fabric filters	Minimising atmospheric emissions and contamination of ash; minimising diffuse emissions of fine wood particles
Wood fuel storage	Closed storage with ventilation; different storages for different qualities, especially contents of pollutants and water content; for wood dust: storage in silos which has to be explosion- proof	Reduction of fine dust particle emissions; prevent odours and the formation of spores;
Wood fuel drying	Drying of the wood fuel by waste heat of the firing; for wood fuels containing > 35 % water: drying is necessary, for example by storage under forced ventilation	Avoiding the reduction of energy efficiency by wet wood fuels, providing ideal combustion conditions in order to minimise emissions

4.2 Major items associated with BAT for the water-steam-cycle and the cooling system

The BAT for the combustion of biomass fuels depends highly on fuel characteristics like water content, particle size, content of impurities and minerals.

Combustion technique	**Rated thermal input [MW$_{th}$]**	**Electric efficiency (related to the LHV)**	**Suitable fuel, water content**	**Primary emission reduction potential**	**Remarks**
Grate furnace	0.5 to 80 (most installations range from 5 to 25)	around 20 % (≥ 50 MW$_{th}$, steam parameters: 60 bar, 450 °C)	< 60 wt.- % water content, particle size 10-300 mm, also wood fuels with high ash content and impurities – problems with fine particles, wood dust	Staged combustion (reduction up to 50 %) and staged air injection for NO$_x$- emission reduction possible, also flue gas re-circulation Further NO$_x$- emission reduction potential by water cooled grates Special grate system: Dual- chamber furnace: Low CO- and C- emissions, however higher NO$_x$- emissions	Wide range of fuel qualities Burnout problems may occur Only slow operation load changes possible
Fluidised bed combustion	BFB > 5 CFB > 10	up to 28 % (≥ 50 MW$_{th}$, steam parameters: 60 bar, 510 °C)	< 40 wt.- % water content, particle size up to 20 mm CFB: non- sensitive to heating value fluctuations	Temperatures below the point of thermally induced NO$_x$- formation CFBC compared to BFBC: Due to longer residence times, higher sorption rates for SO$_2$ and other acid gases are achieved in CFBC Use of in- bed sorbents possible	Ash fusion and agglomeration possible, large quantities of ash, resulting in high specific disposal costs
Dust burner	up to 15		wood dusts, low water content	Low-NO$_x$-burners: reduction potential of 3 – 10 %, Flue gas recirculation: 20 – 35 % reduction air staging in the combustion chamber: up to 85 % reduction	In general auxiliary burners necessary Ideal technology for dusts
Spreader-stoker firing	≥ 5	up to 23 % gross efficiency, steam parameters: 455 °C, 70 bar	fuels with different particle sizes, for ex. mixes of wood dust with chips	fluidised bed supports staged combustion Flue gas recirculation low excess air ratio possible low temperatures (<1250 °C)	Ideal technology for a mix of different particle sizes from dust to chips

4.3 Major items associated with BAT for disposal of the ashes

Process step	**BAT**	**Environmental benefit**
Ash removal	Bed ashes should be removed separately from cyclone ashes or ashes from the FF or ESP	The ash fractions can be disposed of or reused according to their content of nutriments and pollutants; the pollutants concentrated in the ashes of the FF and ESP are not dispersed again
Transport and storage	Ash can be stored and transported either in big bags or closed silos	reduction of fine dust particle emissions;
Disposal/reuse	Ashes with high contents of nutriments and low contents of pollutants may be reused in forestry, according to the demands of the soil	closing of the circuit for the minerals in forests; reduction of the use of artificial fertilizer
	ashes with high content of pollutants: hazardous waste deposits	persistent pollutants as heavy metals are concentrated in the ashes and can be separated from the circuit of substances

Emission levels associated with Best Available Techniques (BAT) for the combustion of biomass are covered in chapter 3.6.

5 Best available techniques (BAT) for the combustion of liquid fuels

The BAT for the combustion of liquid fuels can be divided into five groups as given in section 3.

This division into five groups is possible, as these groups are quite independent from another, which means that, for example, techniques to store and transport liquid fuels can usually be combined with any combustion technique.

5.1 Major items associated with BAT concerning handling, transportation and storage of coal and additives

The environmental key issues for these process steps are fugitive emissions and health and security aspects. The main features are:

Process step	**BAT**	**Environmental benefit**
Storage	Storage tanks should be placed in sealed retention basins which can hold all of the volume of the stored oil	Prevent risk of oil contamination of soil, groundwater and watercourses
Transport and storage of additives	storage of lime or limestone in silos; transport pneumatically; distribution of gases by pipelines; storage of liquids in drums or tanks with acid- or chemical coating	Minimal fine dust particle emission; assuring health and security standards (esp. for toxic substances like NH_3)

5.2 Major issues associated with BAT for the water-steam-cycle and the cooling system

Main environmental issues of these process steps comprise the consumption of ressources (affected by the efficiency), the emission of heat and substances to watercourses and the consumption of auxiliary supplies (chemicals for conditioning of water-steam-cycle and the cooling cycle). The measures to improve the environmental performance comprise those, which are used in newly built plants and those, which can be applied to existing plants for retrofitting. Of course, these BAT are only relevant for plants with boilers.

Process step	**Remarks**	**BAT**	**Environmental benefits/trade-offs**
Superheating of steam (techniques to reach high steam parameters)	new, large boiler	Usage of most advanced materials allows for steam pressures of 300 bars and steam temperatures of 600 °C; these parameters are technically possible, but in the case of HFO-fired boilers often economically not reasonable as CHP is applied and the size of the plant is often too small	These steam parameters result in high overall electrical efficiencies;
Cooling system	boiler, combined cycle	The highest efficiencies can be reached with cooling systems which allow for the lowest pressures in the condenser (< 30 mbar possible!). If only this aspect is taken into account, the following ranking of cooling techniques can be derived: 1) once-through cooling system (seawater or river water) 2) natural draught wet cooling tower 3) hybrid cooling tower 4) mechanical draught wet cooling tower 5) air cooling system	The ranking is only based on the overall efficiency and must be modified by site-specific conditions as some major benefits or threats to the local environment might occur (for more details, the BREF on Industrial Cooling Systems should be consulted): 1) this technique often strongly deteriorates the aqueous eco-systems due to the immission of heat 2) high demand of land and water; shadows 3) smaller than 2) and needs less water, produces virtually no clouds 4) smaller than 2) 5) no water is needed => advantage in arid regions
Cooling system makeup-water treatment	boiler, combined cycle	(see BREF on Industrial Cooling Systems)	
Treatment of water for water-steam circuit	boiler, combined cycle	Reverse osmosis should be used for demineralisation; if this technique alone is not sufficient it can be combined with ion exchangers.	Reverse osmosis allows for smaller loads of salt in the waste water of the treatment system than ion exchangers (40 – 50 % reduction);
		Ion exchangers should work in counter flow operation	Counter flow operation of ion exchangers reduces demand for chemicals and water;
		When decarbonisation is carried out with lime, the sludge should be re-used (cement industry, wet FGD, agriculture)	Reduction of waste disposal
		Conditioning of water: "combined operation": small amounts of ammonia are added (0.1-0.15 g/m^3) together with addition of oxygen (0.05-0.3 g/m^3)	Reduction of nitrogen in the waste water from water-steam-circuit

Process step	Remarks	BAT	Environmental benefits/trade-offs
Steam turbine	new and retro-fitted	Optimised turbine blades and improved in- and outlet lead to efficiencies of 91 – 96 %	
Regenerative feed water heating	new large boiler	High number of stages for regenerative feed water heating increases unit efficiency; new plants use up to 10 stages, resulting in a feed water temperature of about 300 °C or more.	
Reheating	new large boiler	High unit efficiencies are achieved with a double reheat stage	

Major issues associated with BAT for combustion techniques and measures to reduce atmospheric emissions

The BAT for the combustion techniques and the measures to reduce atmospheric emissions are determined in two stages. In one stage, the combinations of combustion techniques and primary and secondary emission control measures which are thought to reflect the best available techniques are listed together with the respective unit efficiencies and the atmospheric emission levels which can be achieved. The second stage comprises the determination of BAT for single process steps for HFO-fired boilers.

Liquid fuels are also used as auxiliary fuels in FBC plants which are fired with solid fuels. The respective emission and consumption levels are described in the fuel specific BAT chapters. The combustion of LFO in boilers or open-cycle gas turbines is not thought to represent BAT as the combined-cycle process offers by far higher efficiencies and economical advantages.

General techniques for HFO-fired boilers

Process step	BAT	Environmental benefits/trade-offs
Emission path of flue gas to the atmosphere	Flue gases should be emitted via the cooling tower if one is used	Reheating of flue gas after the FGD-plant is not necessary resulting in rise of efficiency; no stack is needed
	In case of emission via a stack, 70 – 80 °C are sufficient values for the temperature of the flue gas; energy in flue gas should be used as far as possible in heat exchangers	Reheating can be reduced, resulting in rise of efficiency; cladding inside the stack necessary to prevent corrosion due to condensing acid (SO_3)
	For reheating of flue gas upstream a SCR plant or downstream a FGD, a heat displacement system should be used	Advantages compared to a gas-gas heat exchanger: less HCl/HF-formation
Boiler	Efficiency up to 95 %	High efficiency
	Excess air ratio should be minimised (about 1.05)	Rise of efficiency

Process step	BAT	Environmental benefits/trade-offs
SCR	Separation efficiencies for NO_x range between 80 and 90 %, the NH_3 slip should not exceed 30 mg/Nm^3	
	The SCR plant should be installed in high-dust-configuration if deactivation of catalyser is not too high	Reheating of flue gas is not necessary like in low-dust or tail-end-configuration; this results in rise of efficiency. Trade-off like deactivation of the catalyser in high-dust-configuration might occur.
	Catalysers should be regenerated if they have lost too much of their effectiveness instead of being renewed (two methods are described in this document)	Saving of heavy metal-containing materials and cost reduction
	Storage of ammonia as an aqueous solution, especially if residential sites are in the vicinity of the plant	Safety aspects: if stored as liquid ammonia, the residents might be endangered if the ammonia is set free in case of emergency
FGD	The FGD can be operated with separation efficiencies > 90 %,	Reduction of SO_2-emissions
	All residues can be used (e.g. in gypsum industry, building material industry) and do not have to be disposed of.	
Own electricity demand	Energetic optimisation of fans, coal mills and wet FGD	Rise of efficiency

5.3 Major issues associated with BAT for co-generation of heat and power

The co-generation of heat and power should be a task for any newly built power plant. One major prerequisite is the local demand for heat. As this is often the limiting factor, the size of those CHP plants which are in the scope of the IPPC Directive mostly ranges between 50 and 300 MW$_{th}$. Furthermore, demand for heat often varies strongly throughout the year. This means, that especially CHP plants should be very flexible concerning the ratio of produced heat to electricity and they should posses high efficiencies also for small loads. If only a small amount of heat is needed (e.g. in summer for district heating), it should be possible to rise the electrical efficiency to operate the plant as an efficient power producer.

This flexibility plays an important role in cases with fluctuating demand. like district heating. For other fields, like in certain industrial applications, the heat demand is nearly constant throughout the year and thus the CHP plant can be optimised for a certain heat to power ratio. As the overall efficiency in a specific case strongly depends on the demand curve for heat during the year, the appropriate technique must be derived individually.

5.4 Major issues associated with BAT to treat and minimise waste waters

ELVs and thus treatment techniques are often site-specific as the receiving eco-systems have different sensitivities with regard to certain substances. The following list contains the techniques considered to be BAT for the single sources of waste water.

Source of waste water	**Relevant technique**	**BAT concerning treatment and minimisation of waste water flows**	**Environmental benefits/trade-offs**
Cooling Water	boiler, combined cycle	Usually does not to have to be treated before it is discharged. Exemptions might result from intense conditioning of the cooling water with microbiocides, anti-corrosion substances, water softener or with dispersing agents. Treatment might also be necessary if water from closed cooling systems or water resulting from cleaning of the cooling system is discharged. (see also BREF on Industrial Cooling Systems)	
Waste water from desulphurisation plant (wet FGD)	HFO-fired boiler	Should be treated in several process steps: removal of fluoride (floccluation, sedimentation), removal of heavy metals (flocculation, sedimentation, filtration), removal of COD (ion-exchange) and finally pH-adjustment (neutralisation) (see also section 3.10.1).	
		If ammonia content is too high (e.g. due to SCR/SNCR upstream the FGD), additional reduction measures should be applied (possible techniques: air stripping, precipitation as magnesium-ammonium-phosphate, biodegradation).	
		Waste waters can be minimised by closed-loop operation of the desulphurisation plant.	reduction of waste water
		The mechanically dewatered sludge (mainly gypsum) resulting from sedimentation should be used internally, if possible (e.g. re-use in FGD); it can also be used as filling material for mining industry	minimised waste
		After treatment, the waste water still has high contents of salts (CaCl2, MgCl2, MgSO4); these concentrations can be toxic to soft water organisms; thus, the cleaned waste water should either be discharged together with waste water from other sources with low salt contents (e.g. cooling water) to decrease the salt content of the mix. If this is not possible, the waste water can also be evaporated, whereas the resulting salts are highly leachable and must be disposed of.	protection of soft water organisms
Waste waters from regeneration of demineralisers and condensate polishers	boiler, combined cycle	Reverse osmosis: 15 – 50 % of the amount of produced demineralised water is discharged as waste water, which contains the ingredients of the input water in higher concentrations. This waste water does not have to be treated. Waste water from washing of reverse osmosis system might need treatment before discharge.	
		Waste waters from regeneration and washing of ion exchangers for full water softening or decarbonisation: neutralisation, subsequent sedimentation; the resulting sludge should be dewatered and disposed of.	prevent emission of acid or alkaline waters, dissolved salts and resin particles

Source of waste water	**Relevant technique**	**BAT concerning treatment and minimisation of waste water flows**	**Environmental benefits/trade-offs**
Waste water from elutriation	boiler, combined cycle	If water-steam-system is operated with neutral water, no treatment is necessary before discharge; if alkaline operation is applied, the elutriated water should be neutralised; if the concentration of hydrazine is too high, the waste water should be oxidised in a chemical treatment step. High concentrations of phosphate might also result in additional treatment.	
Waste water from washing of boilers, air preheater and ash precipitator	HFO-fired boiler	Water should be collected and neutralised; further treatment is usually necessary, e.g. in the FGD waste water treatment plant; NH_3 concentration can also be reduced by stripping ; if possible, wet cleansing should be replaced by dry cleansing; the washing process should be realised with closed water loops, i.e. the treated water should be re-used for washing	Reduction of waste water
Waste water from boiler acid washing	boiler, combined cycle	This step is usually done only once, before the first operation of the boiler; the produced waste waters must be neutralised and deposited; the resulting sludge should be dewatered and disposed of.	

5.5 Emission levels associated with Best available techniques (BAT) for the combustion of liquid fuels

5.5.1 Sulphur dioxide emissions

Category	**Size class**	**Fuel type**	**Plant type**	**Primary emission control**	**Secondary emission control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
New plant	IV	Liquid fuels	all			3	200 (dm)	
Existing plant[1)], retrofitted	IV	Liquid fuels	all			3	400 (mm)	
	IV 1007 MW$_{th}$	Heavy fuel oil	Boiler	S-content < 3.5 %	FGD (ws) η > 90 %	3	400 (dm)	50 - 250
	IV 1007 MW$_{th}$	Heavy fuel oil	Boiler	S-content < 3.5 %	FGD (ws) η > 90 %	3	400 (dm)	50 - 250
	IV 510 MW$_{th}$	Residual oil	Boiler	S-content < 3.4 %	FGD (Wellman Lord)	3	400 (dm) SER 15 %	363 (dm) SER 7.9
New plant	II	Liquid fuels	all			3	400 - 200 (dm) linear	
Existing plant[1)], retrofitted	II	Liquid fuels	all			3	1700 (mm)	
	II 130 MW$_{th}$ (3x)	Residual oil	Boiler	S-content < 3.7 %	FGD (ws)	3	400 (dm)	133.5 – 158.9 (am) SER 4.23

5.5.2 Nitrogen dioxide emissions

Category	**Size class Boiler**	**Fuel type**	**Plant type**	**Primary emission control**	**Secondary emission control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
New plant	II – IV I	Liquid fuels	Boiler			3	200 (dm) 400 (dm)	
Existing plant[1)], retrofitted	II – IV I	Liquid fuels	Boiler			3	400 (mm) 450 (mm)	

Category	**Size class Boiler**	**Fuel type**	**Plant type**	**Primary emission control**	**Secondary emission control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
	IV 1007 MW$_{th}$	Heavy fuel oil	Boiler	LNB, over fire air	SCR	3	150 (dm)	121 (am)
	IV 1007 MW$_{th}$	Heavy fuel oil	Boiler	LNB, over fire air	SCR	3	150 (dm)	131 (am)
	IV 510 MW$_{th}$	Residual oil	Boiler	LNB, fuel staging	SCR	3	150 (dm)	127 (dm)
	II 130 MW$_{th}$ (3x)	Residual oil	Boiler		SCR	3	150 (dm)	49.9 – 51.7 (am)
	IV 838 MW$_{th}$	Light fuel oil	Boiler	Water injection		3	150 (dm)	143.3 (dm)
New plant	-	Liquid fuels	GT			3	120 (dm)	
	IV 260 + 655 MW$_{th}$	Light fuel oil	CC GT + Boiler	Water injection		3	240 at full load (dm) (GT: 450 B: 150)	259.7 (dm)
	340 MW$_{th}$ GT 1	Light fuel oil	CC GT	LNB, water injection	-	15	150 (dm)	80 (dm)
	340 MW$_{th}$ GT 2	Light fuel oil	CC GT	LNB, water injection	-	15	150 (dm)	131 (dm)
	I 53 + 25 MW$_{th}$(2 x) GT 1	Light fuel oil	CC GT	Water injection	-	15	200 (dm)	221 (dm)
	I 53 + 25 MW$_{th}$(2 x) GT 2	Light fuel oil	CC GT	Water injection	-	15	200 (dm)	201 (dm)

5.5.3 Dust emissions

Category	Size class Boiler	Fuel type	Plant type	Primary emission control	Secondary emission control	O_2 content [%]	ELV [mg/m^3] (statistics)	Emission [mg/m^3] (statistics)
New plant	II - IV I	Oil	Boiler		ESP, FF	3	30 (dm) 50 (dm)	
Existing plant[1)], retrofitted	all	Oil	Boiler			3	50 (mm)	
	IV 1007 MW$_{th}$	Heavy fuel oil	Boiler		ESP, FGD	3	50 (dm)	10 (am)
	IV 1007 MW$_{th}$	Heavy fuel oil	Boiler		ESP, FGD	3	50 (dm)	15 (am)
	IV 510 MW$_{th}$	Residual oil	Boiler		ESP, FGD	3	50 (dm)	11 (dm)
	II 130 MW$_{th}$ (3x)	Residual oil	Boiler		Wet ESP, FGD	3	50 (dm)	3.9 - 6.6 (am)
	340 MW$_{th}$ GT 1	Light fuel oil	CC GT		-	15	2 (dm)	0.5 (dm)
	340 MW$_{th}$ GT 2	Light fuel oil	CC GT		-	15	2 (dm)	0.5 (dm)

5.5.4 Other pollutants

Category	Size class Boiler	Fuel type	Plant type	O_2 content [%]	CO ELV [mg/m^3] (statistics)	CO [mg/m^3] (statistics)	HCl / HF ELV [mg/m^3]	HCl / HF [mg/m^3]	N_2O [mg/m^3]
	IV 838 MW$_{th}$	Light fuel oil	Boiler	3	100 (dm)	4.8 (dm)			
	IV 1007 MW$_{th}$	Heavy fuel oil	Boiler	3	175 (dm)	50 (am)	30 / 5	0.2 / < 0.1	-
	IV 1007 MW$_{th}$	Heavy fuel oil	Boiler	3	175 (dm)	50 (am)	30 / 5	0.1 / < 0.1	-
	IV 510 MW$_{th}$	Residual oil	Boiler	3	175 (dm)	7 (dm)	30 / 5	15 / 0.4	-

Category	**Size class Boiler**	**Fuel type**	**Plant type**	**O_2 content [%]**	**CO ELV [mg/m^3]** (statistics)	**CO [mg/m^3]** (statistics)	**HCl / HF ELV [mg/m^3]**	**HCl / HF [mg/m^3]**	**N_2O [mg/m^3]**
	II 130 MW_{th} (3x)	Residual oil	Boiler	3	175 (dm)	9.2- 22.1 (am)	30 / 5	2 / <0.2	-
	IV 260 + 655 MW_{th}	Light fuel oil	CC GT + Boiler	3	160 at full load (dm) (GT: 300 B: 100)	130 (dm)			
	340 MW_{th} GT 1	Light fuel oil	CC GT	15	100 (dm)	19 (dm)			
	340 MW_{th} GT 2	Light fuel oil	CC GT	15	100 (dm)	14 (dm)			
	I 53 +25 MW_{th}(2 x) GT 1	Light fuel oil	CC GT	15	100 (dm)	8.2 (dm)			
	I 53 +25 MW_{th} (2 x) GT 2	Light fuel oil	CC GT	15	100 (dm)	7.7 (dm)			

6 Best available techniques (BAT) for the combustion of gaseous fuels

The BAT for the combustion of gaseous fuels can be divided into the same five groups as given in section 3. This division into five groups is possible, as these groups are quite independent from another, which means that, for example, techniques to store and transport gas can usually be combined with any combustion technique.

6.1 Major items associated with BAT concerning handling, transportation and storage of gaseous fuels

The BAT to minimise risks in these sectors include:

Process step	**BAT**	**Environmental benefit**
Storage	Storage on-site is not practised	
Transport and unloading	Decompression of gas from supply line in an expansion turbine in order to recover the compression energy partly	Efficient use of resources
	Heating of decompressed gas with waste heat	Rise of efficiency
Transport and storage of additives	Storage of liquids in drums or tanks with acid- or chemical coating	Asuring health and security standards (esp. for toxic substances like NH_3)

6.2 Major issues associated with BAT for the water-steam-cycle and the cooling system

These process steps are only relevant for boilers and combined cycle plants.

Main environmental issues of these process steps comprise the consumption of resources (affected by the efficiency), the emission of heat and substances to watercourses and the consumption of auxiliary supplies (chemicals for conditioning of water-steam-cycle and the cooling cycle). The measures to improve the environmental performance comprise those, which are used in newly built plants and those, which can be applied to existing plants for retrofitting.

Process step	**Remarks**	**BAT**	**Environmental benefits/trade-offs**
Superheating of steam (techniques to reach high steam parameters)	new, large PP	Usage of most advanced materials allows for steam pressures of 300 bars and steam temperatures of 600 °C; these parameters can only be achieved with a Benson-type boiler.	These steam parameters result in high overall electrical efficiencies;
Cooling system	-	The highest efficiencies can be reached with cooling systems which allow for the lowest pressures in the condenser (< 30 mbar possible!). If only this aspect is taken into account, the following ranking of cooling techniques can be derived: 1) once-through cooling system (seawater or river water) 2) natural draught wet cooling tower 3) hybrid cooling tower 4) mechanical draught wet cooling tower 5) air cooling system	The ranking is only based on the overall efficiency and must be modified by site-specific conditions as some major benefits or threats to the local environment might occur (for more details, the BREF on Industrial Cooling Systems should be consulted): 1) this technique often strongly deteriorates the aqueous eco-systems due to the immission of heat 2) high demand of land and water; shadows 3) smaller than 2) and needs less water, produces virtually no clouds 4) smaller than 2) 5) no water is needed => advantage in arid regions
Cooling system makeup-water treatment	-	(see BREF on Industrial Cooling Systems)	
Treatment of water for water-steam circuit	-	reverse osmosis should be used for demineralisation; if this technique alone is not sufficient it can be combined with ion exchangers.	reverse osmosis allows for smaller loads of salt in the waste water of the treatment system than ion exchangers (40 – 50 % reduction);
	-	ion exchangers should work in counter flow operation	counter flow operation of ion exchangers reduces demand for chemicals and water;
	-	When decarbonisation is carried out with lime, the sludge should be re-used (cement industry, wet FGD, agriculture)	reduction of waste disposal
	-	Conditioning of water: “combined operation”: small amounts of ammonia are added (0.1-0.15 g/m^3) together with addition of oxygen (0.05-0.3 g/m^3)	Reduction of nitrogen in the waste water from water-steam-circuit

Process step	Remarks	BAT	Environmental benefits/trade-offs
Steam turbine	new/retro-fitting	Optimised turbine blades and improved in- and outlet lead to efficiencies of 91 – 96 %	
Regenerative feed water heating	new large PP	High number of stages for regenerative feed water heating increases unit efficiency;	
Reheating	new large PP	high unit efficiencies are achieved with a double reheat stage	

6.3 Major issues associated with BAT for co-generation of heat and power

The co-generation of heat and power should be a task for any newly built power plant. One major prerequisite is the local demand for heat. As this is often the limiting factor, the size of those CHP plants which are in the scope of the IPPC Directive mostly ranges between 50 and 300 MW_{th}. Furthermore, demand for heat often varies strongly throughout the year. This means, that especially CHP plants should be very flexible concerning the ratio of produced heat to electricity and they should posses high efficiencies also for small loads. If only a small amount of heat is needed (e.g. in summer for district heating), it should be possible to rise the electrical efficiency to operate the plant as an efficient power producer. This flexibility plays an important role in cases with fluctuating demand like district heating. For other fields, like in certain industrial applications, the heat demand is nearly constant throughout the year and thus the CHP plant can be optimised for a certain heat to power ratio.

As the overall efficiency in a specific case strongly depends on the demand curve for heat during the year, the best technique must be derived individually.

6.4 Major issues associated with BAT for to treat and minimise waste waters

ELVs and thus treatment techniques are often site-specific as the receiving eco-systems have different sensitivities concerning the immissions of certain substances. The following list contains the techniques considered to be BAT for the single sources of waste water.

Source of waste water	**BAT concerning treatment and minimisation of waste water flows**	**Environmental benefits/trade-offs**
Cooling Water	Usually does not to have to be treated before it is discharged. Exemptions might result from intense conditioning of the cooling water with microbiocides, anti-corrosion substances, water softener or with dispersing agents. Treatment might also be necessary if water from closed cooling systems or water resulting from cleaning of the cooling system is discharged. (see also BREF on Industrial Cooling Systems)	
Waste waters from regeneration of demineralisers and condensate polishers	Reverse osmosis: 15 – 50 % of the amount of produced demineralised water is discharged as waste water, which contains the ingredients of the input water in higher concentrations. This waste water does not have to be treated. Waste water from washing of reverse osmosis system might need treatment before discharge.	
	waste waters from regeneration and washing of ion exchangers for full water softening or decarbonisation: neutralisation, subsequent sedimentation; the resulting sludge should be dewatered and disposed of.	Prevent emission of acid or alkaline waters, dissolved salts and resin particles
Waste water from elutriation	If water-steam-system is operated with neutral water, no treatment is necessary before discharge; if alkaline operation is applied, the elutriated water should be neutralised; if the concentration of hydrazine is too high, the waste water should be oxidised in a chemical treatment step. High concentrations of phosphate might also result in additional treatment.	
Waste water from boiler acid washing waste water from gas turbine washing	This step is usually done only once, before the first operation of the boiler; the produced waste waters must be neutralised and deposited; the resulting sludge should be dewatered and disposed of.	
Waste water from gas turbine washing	Usually should be disposed of due to detergents	

6.5 Emission levels associated with Best Available Techniques (BAT) for the combustion of gaseous fuels

6.5.1 Nitrogen dioxide emissions

Category	**Size class Boiler**	**Fuel type**	**Plant type**	**Primary emission control**	**Secondary em. control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
New plant	III, IV I, II	Natural gas	Boiler			3	100 (dm) 150 (dm)	
New plant	all	Other gases	Boiler			3	200 (dm)	
Existing plant[1)], retrofitted	IV I-III	Gases	Boiler			3	200 (mm) 300 (mm)	
New plant	-	Natural gas	GT			15	50 – 75 (dm)	
New plant	-	Other gases	GT			15	120 (dm)	
	II 135 + 49 MW_{th}(3 x)	Natural gas	CC GT + Boiler	Steam injection	-	13.3	116 (dm)	73 (dm)
	IV 1014 MW_{th}	Natural gas	CC GT	LNB, water injection	-	15	80 (dm)	47 (mm)
	340 MW_{th} GT 1	Natural gas	CC GT	LNB, water injection	-	15	100 (dm)	76 (dm)
	340 MW_{th} GT 2	Natural gas	CC GT	LNB, water injection	-	15	100 (dm)	66 (dm)
	II 184 MW_{th}	Natural gas	CC GT		-	15	100 (dm)	70 (dm)
	II 135 + 49 MW_{th}(3 x)	Natural gas	CC GT	Steam injection	-	15	100 (dm)	82 (dm)
	II 67.8 MW_{el} + 26.5 MW_{th} (2 x)	Natural gas	CC GT	LNB, water injection	-	15	Max. 85 (dm)	60 (mm)
	GT 60 MW_{el} (2 x)	Natural gas	CC GT	LNB	-	15	100 (dm)	42
	I 72 MW_{th}	Natural gas	CC GT	LNB	-	15	150 (dm)	18.4 (dm, range 15 – 30)
	I 53 + 25 MW_{th}(2 x) GT 1	Natural gas	CC GT	Water injection	-	15	150 (dm)	100 (dm)
	I 53 + 25 MW_{th}(2 x) GT 2	Natural gas	CC GT	Water injection	-	15	150 (dm)	121 (dm)

Category	**Size class Boiler**	**Fuel type**	**Plant type**	**Primary emission control**	**Secondary em. control**	**O_2 content [%]**	**ELV [mg/m^3]** (statistics)	**Emission [mg/m^3]** (statistics)
	IV 295 MW_{el}	Industrial gases	Boiler B 1	LNB, Flue gas recirculation	-	3	100 – 150 (dm)	60 (dm)
	IV 295 MW_{el}	Industrial gases	Boiler B 2-4	LNB, Flue gas recirculation	-	3	100 – 150 (dm)	58 - 60 (dm)
	IV 295 MW_{el}	Industrial gases	Boiler B 5	LNB, Flue gas recirculation	-	3	100 – 150 (dm)	93 (dm)
	II 130 MW_{th}	Refinery gas	Boiler	LNB, Water injection		3	100 (dm)	94 (am)
	II 92 MW_{th}	Natural gas	Boiler	LNB		3	100 (dm)	79 (am)

6.5.2 Other pollutants

Size class	**Fuel type**	**Plant type**	**O_2 content [%]**	**CO ELV [mg/m^3]** (statistics)	**CO [mg/m^3]** (statistics)	**SO_2 ELV [mg/m^3]** (statistics)	**Dust ELV [mg/m^3]**	**Dust [mg/m^3]**
II 135 + 49 MW_{th}(3 x)	Natural gas	CC GT + Boiler	13.3	100 (dm)	60 (dm)			
IV 1014 MW_{th}	Natural gas	CC GT	15	50 (dm)	15 (mm)	12 (dm)	5	0.1
340 MW_{th} GT 1	Natural gas	CC GT	15	100 (dm)	6.7 (dm)	-	2 (dm)	0.2 (dm)
340 MW_{th} GT 2	Natural gas	CC GT	15	100 (dm)	11.3 (dm)	-	2 (dm)	0.2 (dm)
II 184 MW_{th}	Natural gas	CC GT	15	100 (dm)	20 (dm)			
II 135 + 49 MW_{th}(3 x)	Natural gas	CC GT	15	100 (dm)	9 (dm)			
II 67.8 MW_{el} + 26.5 MW_{th} (2 x)	Natural gas	CC GT	15	Max. 40 (dm)	6 (mm)			
GT 60 MW_{el} (2 x)	Natural gas	CC GT	15	100 (dm)	1.8			
I 72 MW_{th}	Natural gas	CC GT	15	100 (dm)	6.5 (dm, range 0-20)			

Size class	**Fuel type**	**Plant type**	**O_2 content [%]**	**CO ELV [mg/m^3]** (statistics)	**CO [mg/m^3]** (statistics)	**SO_2 ELV [mg/m^3]** (statistics)	**Dust ELV [mg/m^3]**	**Dust [mg/m^3]**
I 53 + 25 MW$_{th}$(2 x) GT 1	Natural gas	CC GT	15	100 (dm)	0.1 (dm)			
I 53 + 25 MW$_{th}$(2 x) GT 2	Natural gas	CC GT	15	100 (dm)	0.1 (dm)			
IV 295 MW$_{el}$	Industrial gases	Boiler B 1	3	100-150 (dm)	10 (dm)	200 –700 (dm)	100 (dm)	0.9 (dm)
IV 295 MW$_{el}$	Industrial gases	Boiler B 2-4	3	100-150 (dm)	7 – 9 (dm)	35 –800 (dm)	5-50 (dm)	0.7 –2.3 (dm)
IV 295 MW$_{el}$	Industrial gases	Boiler B 5	3	100-150 (dm)	14 (dm)	35 – 700 (dm)	5 –50 (dm)	0.95 (dm)
II 130 MW$_{th}$	Refinery gas	Boiler	3	100 (dm)	15 (am)	35 (dm)	5 (dm)	0.01 (am)
II 92 MW$_{th}$	Natural gas	Boiler	3	100 (dm)	1 (am)	35 (dm)	-	-

7 Best available techniques (BAT) for the co-combustion of waste and secondary fuels

Before the BAT associated with the co-incineration of waste and refuse-derived fuels are specified, it is important to point out, that in this context, no alternative processes to treat these materials are taken into account. In a situation, where different alternatives to treat waste are compared and evaluated, these other techniques are of course taken into account. Thus, the issues associated with BAT in this document should not be understood to reflect the best way (in an economical and ecological sense) to treat certain waste materials. Other alternatives like waste incineration, disposal, recycling etc. must also be included for this approach.

The issues specified here could be applied in two different ways:

- if the decision about the way of treatment of certain waste materials is not yet made, the issues specified here might help to evaluate co-incineration as **one** alternative amongst others.
- if one has already arrived at the decision to realise co-combustion, the issues specified here might help to perform it in a environmentally and economically sound way.

7.1 Main issues associated with BAT for the evaluation of co-incineration projects

The main environmental issues, which must be considered at the evaluation of co-incineration projects are the additional emissions into the atmosphere and the additional pollution of residues and waste waters. In some cases, health aspects can also play a role.

7.1.1 Atmospheric emissions

For the evaluation of the additional load of impurities in the flue gas, the flue gas flow related to the combustion of the waste materials should be separated from the total current in a calculative way. For this separated current, the concentrations of pollutants should be derived to compare them with the ELVs from European legislation on waste incineration. A method to derive these concentrations with the help of distribution factors from a set of existing plants is the mass flow analysis. Of course, these concentrations can also be measured for a single plant, which often turns out to be quite costly. This approach to evaluate the atmospheric emissions prevents the possibility of “filling up” the gap between the emission level for the standard fuel and the ELV for the co-incineration mode. The following example is supposed to illustrate this circumstance:

The mercury concentration in the flue gases of a hard coal fired power plant amounts to about 8 µg/Nm^3. There is no ELV for the combustion of coal. The ELV for the incineration as well as for the co-incineration of waste amounts to 50 µg/Nm^3, according to EC directive 2000/76/EC. Let us assume that the combustion of waste in the coal-fired power plant accounts for 5 % of the total flue gas current. The emission of mercury from the incinerated waste amounts to 12 µg/Nm^3. If only the ELV is applied to the total current, the measured value is by far lower than the ELV whereas the calculated concentration of mercury in the "virtual current" resulting from the combustion of waste materials amounts to 88 µg/Nm^3 and is thus far above the ELV. This example demonstrates clearly the different results for the two approaches and the way, in which the ELV can be "filled up" by waste materials if only the total flue gas current is observed.

In the end, this circumstance leads to higher mass-specific emissions from co-incineration of waste than from incineration. Thus, the flue gas current from the combustion of waste should always be taken into account separately at least before the commissioning of a co-incineration plant although this is not part of EC directive 2000/76/EC.

7.1.2 Additional pollution of residues and waste waters

As waste materials often contain high concentrations of chlorine, fluorine, dioxins/furans and all kinds of metal elements, these elements enrich in the residues if they are not emitted via the air path:

- chlorine and fluorine are usually separated together with the sulphur oxide and thus do enrich in the residues of the FGD process (gypsum, dry sorption residue, waste water, etc.); it should be made sure, that the utilisation of the residues does not have to be changed due to co-incineration. (e.g. high chlorine contents in the gypsum might impede utilisation in the building material industry)
- the quality of the waste water should not change significantly; if necessary, additional measures should be installed to assure the quality (esp. concerning the heavy metal content!)
- the residues (especially the ash) often contain higher concentrations of heavy metals than for the combustion of the standard fuel; it should be made sure, that the utilisation of the residues does not have to be changed due to co-incineration. The leachability should be tested if concentrations of heavy metals do increase due to co-incineration. This parameter helps to evaluate the mobility of metals in an aqueous environment. It must be added, that the leachability test strongly depends on the pH-value of the fluid used for the test. The leachability should also be tested for acid conditions (pH-value ~ 4) to simulate potential landfill conditions
- it should be made sure, that dioxins and furans in the waste material are completely destroyed (T > 850 °C, residence time > 2.5 s). Furthermore, the de-novo synthesis

should be prevented by quickly cooling down the flue gas from 450 to 250 °C and by assuring small concentrations of chlorine in the flue gas.

7.1.3 Main issues associated with BAT – actual technical measures

In this paragraph, some technical measures are specified which should be applied in the given cases. The main guideline for any co-incineration project should be, that the power plant should reflect BAT for the standard fuel as it is described in the fuel specific chapters.

Process step	**BAT**	**Environmental benefits**
Emission control	If concentration of heavy metals or dioxins in the flue gas is too high (the flue gas current resulting from the combustion of the waste material should be separated for doing this, see above), additional measures should be applied. Existing power plants may be retrofitted with systems for the injection of sorbents like activated carbon or activated coke upstream the dedusting unit. In the dust filter, the loaded sorbent is then separated.	Reduction of atmospheric emissions (heavy metals, PCDD/PCDF)
Treatment / handling of waste fuel	Impurities should be filtered out as far as possible	Ensuring compliance with atmospheric ELVs and quality of residues
	Quality should be checked regularly	
	If fuel contains infectious or toxic materials (e.g. sewage sludge, meat and bone meal, etc.) security measures must be applied to protect the health of staff: prevent formation of dust at loading and transportation, no direct contact of staff with waste materials, protective clothes (gloves, goggles, overalls, etc.)	Health aspects
Fuel quality	Concentration of impurities should be limited to fulfil the criteria, which are specified in the paragraph "Main issues associated with BAT for the evaluation of co-incineration projects"	Ensuring compliance with atmospheric ELVs and quality of residues
Fuel quality	The share of waste and recovered fuels in the total fuel input should be limited to allow for a undisturbed operation of the plant and to fulfil the criteria, which are specified in the paragraph "Main issues associated with BAT for the evaluation of co-incineration projects"	Ensuring compliance with atmospheric ELVs and quality of residues