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Determination of costs for activities of annexes IV, V and VII

Sector: Boilers and Process Heaters

Preamble: This document has been composed to fulfil the task of assigning cost parameters to options discussed in the light of revising the Gothenburg Protocol. Providing representative cost data for general use is challenging, as site issues and country-specific issues may affect investment and operating costs severely.

In the case of boilers and process heaters for large combustion plants, many different primary and secondary abatement techniques, combinations of techniques and multi-pollutant techniques are declared as best available techniques. This is due to the large number of fuels, the possibility of co-combustion and various combustion techniques, which all lead to highly different pollutant raw gas concentrations and corresponding ELV options. Due to a generally low level of available representative technique and cost data, this document has to focus on boilers > 300 MW_{th}.

Options in the Gothenburg Protocol

The Gothenburg Protocol rules NO_x, SO_2 and dust emissions from boilers and process heaters in large combustion plants (LCP). LCPs are divided into three different categories, 50-100 MW_{th},100-300 MW_{th} and plants > 300 MW_{th}, with ELVs existing for each category and each fuel. Concerning solid fuels, the use of hard coals, pulverised lignite, biomass and peat for pulverised and fluidised bed combustion is differentiated. Liquid fuels are allocated one single ELV for each size class; gaseous fuels are divided into natural gas, liquefied gas, low calorific value gases and other gases. The Gothenburg Protocol has differing NO_x, ELVs for plants below and above 300 MW_{th}, for SO_2 and dust only size-independent ELVs.

Technical Introduction

Dust abatement:

Dedusting equipment is needed for solid and liquid fuel combustion, not for gaseous fuel combustion. Dedusting BAT are mostly Electrostatic Precipitators (ESP) or Fabric Filters (FF), but ESPs are applied in most cases. ESPs are usually dry ESPs, varying from 2-field ESPs to 5 - 6 field ESPs. Accordingly, BAT AELs, investment and operating costs cover a wide range, due to which ESP cost and AELs have to be split up for each category. Though different filter materials can be selected for FFs, BAT AELs are more or less the same for relevant materials. All plants equipped with wet flue gas desulphurisations (wet FGDs) are capable of reducing the post-filter emissions further by 70-90%, if wet FGDs are designed and operated properly. Hence, for the evaluation of associated techniques and their costs to ELVs, this has to be taken into account. Table 1 shows achievable emissions for the various ESPs and FF with and without wet FGDs.

Table 1: Achievable dust emission limits for various types of dedusting equipment

Technique	# fields	Stand alone	With wet FGD
Type	No.	mg/Nm^3	mg/Nm^3
FF	-	<10	<5
ESP	2	~50	~30
ESP	3	~30	<20
ESP	4	~10	<5
ESP	6	~5-6	<5

In tables 2, 3 and 4 ELVs and achievable emission limits (table 1) are matched for new (subtable 1, left part) and for existing (subtable 2, right part) boilers and process heaters for solid fuels. Cells filled with "FGD?" mean, that the selected technique and an additional wet FGD might not necessarily comply with the option in all cases. "FDG req.?" means, that a wet FGD might be required additionally for this technique to comply with the ELV. **If focusing on emission levels of 10 or 20 mg/Nm^3 for existing and new plants > 300 MW_{th}, the table shows, that either 3-field or 4-field ESPs plus (or without) wet FGDs comply with these emission levels. 5- or 6-field ESPs achieve clean gas concentrations far below all discussed ELV options, 2-field ESPs cannot meet the emission levels even in combination with wet FGDs in most cases. For smaller plants, 2-field ESP plus wet FGD may be a choice in the case of option 3, but small plants do not tend to have wet FGDs installed.**

Table 2: Achievability of ELV options with selected techniques for new and existing solid fuel firing plants > 300 MW_{th} where "FGD?" means that the selected technique and an additional wet FGD might not necessarily comply with the option, whereas "FDG req.?" means, that a wet FGD might be required additionally for this technique to comply with the ELV.

Table 2.1	Options – New Plants			Table 2.2	Options – Existing Plants		
Technique	1	2	3	Technique	1	2	3
ELV	10	10[1]	30	ELV	10	20	50
FF	Y	Y	Y	FF	Y	Y	Y
2-ESP	N	N	FGD?	2-ESP	N	N	FGD req.?
3-ESP	N	N	Y	3-ESP	N	Y	Y
4-ESP	FGD req.?	FGD req.?	Y	4-ESP	FGD req.?	Y	Y
6-ESP	Y	Y	Y	6-ESP	Y	Y	Y

[1] For biomass and peat; Opt.2: 20 mg/Nm^3

Table 3 Achievability of ELV options with selected techniques for new and existing solid fuel firing plants between 100 and 300 MW_{th} where "FGD?" means that the selected technique and an additional wet FGD might not necessarily comply with the option, whereas "FDG req.?" means, that a wet FGD might be required additionally for this technique to comply with the ELV.

Table 3.1	Options – New Plants			Table 3.2	Options – Existing Plants		
Technique	1	2	3	Technique	1	2	3
ELV	10	20	30	ELV	15[2]	25[3]	50
FF	Y	Y	Y	FF	Y	Y	Y
2-ESP	N	N	FGD?	2-ESP	N	N	FGD req.?
3-ESP	N	FGD req.	FGD?	3-ESP	N	FGD req.	Y
4-ESP	FGD req.?	Y	Y	4-ESP	Y	Y	Y
6-ESP	Y	Y	Y	6-ESP	Y	Y	Y

Table 4 Achievability of ELV options with selected techniques for new and existing solid fuel firing plants between 50 and 100 MW_{th} where "FGD?" means that the selected technique and an additional wet FGD might not necessarily comply with the option, whereas "FDG req.?" means, that a wet FGD might be required additionally for this technique to comply with the ELV.

Table 4.1	Options – New Plants			Table 4.2	Options – Existing Plants		
Technique	1	2	3	Technique	1	2	3
ELV	10	20	50	ELV	15	30	50
FF	Y	Y	Y	FF	Y	Y	Y
2-ESP	N	N	FGD req.?	2-ESP	N	FGD?	FGD req.?
3-ESP	N	FGD req.	Y	3-ESP	N	FGD req.?	Y
4-ESP	FGD req.?	Y	Y	4-ESP	Y	Y	Y
6-ESP	Y	Y	Y	6-ESP	Y	Y	Y

It has to be kept in mind, that plants with special dust and flue gas characteristics might need an additional field or one field less to reach the same dust concentration. The dust abatement efficiency of wet FGDs decreases with a lower dust concentration.

[2] For biomass and peat Opt.1: 10 mg/Nm³
[3] For biomass and peat Opt.2: 20 mg/Nm³

NO_x abatement

Pulverised hard coal boilers can use low NO_x burners (LNB) in combination with various further primary combustion modifications and selective catalytic reduction (SCR) to reach the selected ELVs. Pulverised lignite boilers do only need LNB and combustion modifications to reach the ELVs. In case of fluidised bed combustion technologies, LNBs are not possible. Depending on the options and raw gas NO_x concentration, flue gas recirculation, selective non-catalytic reduction (SNCR) or SCR are required techniques to comply with the ELVs.

As the technical difference in new LNBs for new plants and newly retrofitted LNBs for existing plants (incl. burner management systems, firing control and boiler wall refurbishments) is expected to be not very high, the following matching process does only differentiate between “new LNBs” and “no new LNBs”. Furthermore, it focuses on pulverised coal combustion.

If an ELV of 100 mg/Nm³ NO_x is chosen, all hard coal and lignite fired plants need LNBs of newest generation and carefully designed SCRs.

If an ELV of 150 mg/Nm³ NO_x is chosen, hard coal fired power plants need SCR, but not necessarily new generation LNBs, as many LCPs retrofitted in the 1990ies achieve NO_x emission values of < 150 mg/Nm³. Lignite fired plants may not in all cases reach 150 mg/Nm³ with old and new LNBs. Therefore, sometimes additional secondary abatement techniques, in general SNCR, might be required to retrofit.

If an ELV of 200 mg/Nm³ is chosen, lignite fired power plants can comply with this ELV using fairly modern LNBs. Hard coal fired power plants need SCR, but not necessarily new generation LNBs.

Installations with fludised beds are usually found in the small or medium-size class. Usually no SCR is required to comply with the ELV options. If certain ELVs cannot be met right away, combustion modification, biomass co-firing and in rare cases SNCR can be used to reduce the NO_x concentration.

For liquid fuel fired units, especially heavy fuel fired boilers and process heaters, situation is quite similar to pulverised hard coal combustion. LNBs, combustion modifications, SNCR and SCR are available techniques. All ELVs of 200 mg/Nm³ and lower should imply the use of SCR, whereas higher ELVs may be fulfilled using new generation LNBs only and in certain cases SNCR. As current legislation does not require a broad application of SNCR, experience is very limited and does not allow a representative assessment of the effectiveness for liquid fuels. However, reduction efficiencies of 25% and more should be possible, as the few European and US-American installations show..

Natural gas fired units can reach 80 mg/Nm³ with combustion modifications. In certain cases SNCR or SCR might be required, but most units should not need to install secondary abatement techniques. For other gaseous fuels ELV options are higher, therefore combustion modifications and fuel mixture should be sufficient. But as “other fuels” (Coke Oven Gas, Blast Furnace Gas, BOF Gas, Refinery Gas, etc.) vary largely in composition, heating value and combustion temperature, general implications cannot be deducted.

SO_2 abatement

Theoretically, a reduction of SO_2 emissions can be achieved by the use of fuels with lower sulphur content. Secondary SO_2 abatement techniques use the principle of combustion chamber or flue gas alkaline injection (dry, semi-dry or wet). The alkaline used in most cases is lime, limestone, calcium hydroxide or $NaHCO_3$, in certain cases seawater as well. Alkaline injection in the combustion chamber is BAT for fluidised bed combustion. Pulverised hard coal, lignite and heavy fuel oil fired units use mostly wet FGDs or dry and semi-dry sorption systems, which inject alkaline in the flue gas duct. Selected technique and required reduction efficiency mostly depends on the fuel sulphur content.

Experience shows that LCP fired with imported hard coal do not necessarily have to install wet FGD systems to reach SO_2 clean gas concentrations of 200 or 150 mg/Nm³, but can use semi-dry sorption FGD as well[4] if the sulphur content of fired coals is low enough.

Investment data

Interpreting and generalising collected cost data is very difficult, as site-specific factors may largely influence costs. Illustrative examples are space restrictions (leading to expensive steelworks), split-ups of existing equipment, required demolition works or even sea-weather influences. When comparing collected cost data, care must be taken to ensure that it reflects the entire costs associated with an abatement technique. Collected cost data for abatement techniques for installing abatement techniques vary from turnkey costs to process equipment-only costs (flange-to-flange, process equipment and steelwork). For example in wet FGD cases, turnkey prices can be 80 – 100% above flange-to-flange prices, as foundation works, duct-works, gypsum and lime(stone)- storage and chimney modifications need to be included for total (turnkey) cost calculations. Not included are opportunity costs due to outage time, if applicable.

Table 5 shows specific investments needed for installing abatement techniques. The comment row states explanatory information for interpreting the costs. Especially SCR cost data show the inherent variability of site and scope issues. The cost data from the Danish plants (Studstrup, Esbjerg, Fynsvaerket) are expected to be equipment and steelwork prices and do not reflect major special issues, such as severe seawater and corrosion effects. Le Havre IV is regarded to be a turnkey project and its price suffered under seawater salt and corrosion issues at the site (special and expensive steel required).

Stated wet FGD prices are expected to be turnkey- rather than process equipment-only ("Rumpf-REA") prices. "Rumpf-REA" prices for new installations and import coals (< 1% S) are expected to be around 50% of the stated values.

All ESP and PJFF prices are design flange-to-flange (process equipment + steelworks) equipment manufacturer prices. All clean gas concentrations are post-filter and not post-FGD values. For ELV-option decisions, additional dust abatement of wet FGDs has to be added (70-90% abatement efficiency is expected for 3- and 4-field ESPs – abatement efficiency decreases for lower dust concentrations, i. e. for 5- or 6-field ESPs and FFs). ESP and FF prices do not reflect major site-issues and retrofit difficulties. Furthermore, investment for upgrading ESPs by a certain number of fields cannot be deducted from price differences. In most cases, operators have to demolish the existing and build a completely new ESP. Whether adding single fields is possible, is highly site specific. For these cases, equipment costs should be of minor influence on total cost, as construction, demolition and plant layout changing costs are expected to be much higher. Relevant data could not be collected and is hardly predictable.

In cases of combined installation of flue gas cleaning techniques (i. e. two techniques separately but as one order) costs should be additive. Synergy effects do not occur in equipment and steelwork, as they are independent constructions.

[4] Umweltbundesamt Österreich: „Entschwefelungstechnologien – die Situation in Österreich", 2002.

Table 5: Specific investments of recent retrofitted flue gas abatement techniques at hard coal fired power plants across Europe

Technique	Power Plant Unit and Size	Specific Price [€/kW_{el}] [year]	Comment	Source
Selective Catalytic Reduction (SCR)				
SCR	Studstrup, 2x360 MW_{el}	24.30 [ref. year unknown]	Site with high complexity, start of operation 2006 and 2007	IEA CCC[5]
SCR	Esbjerg, 380 MW_{el}	31.86 [ref. year unknown]	Incl. air heater modifications, plant site was "SCR-ready", start of operation 2005	IEA CCC
SCR	Fynsvaerket, 400 MW_{el}	40.42 [ref. year unknown]	Incl. economiser splitting, start of operation 2007	IEA CCC
SCR	Israel Power Co., 4x575 MW_{el}	43.48 [2011]	Process equipment incl. catalyst, steelwork, ductwork and control equipment	Bilfinger Berger[6]
SCR	Sines, 320 MW_{el}	68.75 [ref. year unknown]	Seawater & Corrosion resistant	EGTEI Expert
SCR	Le Havre IV, 580 MW_{el}	86.21 [ref. year unknown]	Seawater & Corrosion resistant, cost basis probably 2005	IEA CCC
Wet Flue Gas Desulphurisation (Wet FGD)				
Wet FGD	Unknown UK, 4x500 MW_{el}	73.38 [2000]		IEA CCC
Wet FGD	Unknown UK, 4x500 MW_{el}	80.84 [2000]	Design S-Content of Coal: 1,7%	IEA CCC
Electrostatic Precipitators (ESP)				
ESP	Design, 800 MW_{el}	25.90 [2008]	< 30 mg/Nm³, 3-field ESP, equipment and steelworks	Riepe[7]
ESP	Design, 800 MW_{el}	29.40 [2008]	< 20 mg/Nm³, 4-field ESP, equipment and steelworks	Riepe
ESP	Design, 800 MW_{el}	36.30 [2008]	< 6 mg/Nm³, 5 or 6-field ESP, equipment and steelworks	Riepe
ESP	Design, 1,100 MW_{el}	32.70 [2008]	< 10 mg/Nm³, 4 or 5-field ESP, equipment and steelworks	Riepe
ESP	Design, 1,100 MW_{el}	41.80 [2008]	< 5 mg/Nm³, 5 or 6-field ESP, equipment and steelworks	Riepe
Pulse Jet Fabric Filters (PJFF)				
PJFF	Design, 750 MW_{el}	19.70 [2008]	< 5 mg/Nm³, equipment and steelworks, PAN filter bags	Riepe

[5] Herminé Nalbandian: "Economics of retrofit air pollution control technologies", IEA CCC report, 2006.
[6] See press release „Saubere Energie für Israel", Bilfinger Berger, available on company website, 28.02.2011.
[7] Thomas Riepe: „Elektrofilter und Gewebefilter für kohlegefeuerte Kraftwerke im Vergleich", held at: 4. Conference on „Grundlagen, Betriebserfahrungen, Optimierungsmaßnahmen und Sonderverfahren für Rauchgasreinigungsanlagen", Essen (Germany), 2008.

PJFF	Design, 750 MW_{el}	21.00 [2008]	< 5 mg/Nm³, equipment and steelworks, PPS filter bags	Riepe

Operating Cost

Dust abatement

FF and ESP both face energy costs due to pressure losses and equipment heating. FFs have 2 to 3 times higher pressure losses (10-12 mbar compared to 3-4 mbar for an ESP achieving < 5 mg/Nm³[8]) and need energy for pulse jet cleaning as well. However, the largest energy consumer in ESPs is not the pressure loss but the electrode. In total, FFs are expected to have higher energy consumption; Riepe estimates 30% (1,360 kW vs. 1,060 kW for dust < 5 mg/Nm³ in a 800 MW_{el} hard coal unit). In addition to energy consumption, FF bags have an estimated lifetime of 4 to 6 years. Bag exchange costs are high. In general, revenues may arise of dust sales to construction industry. Prices depend on dust quality.

NO_x abatement

Low NO_x burners and overfire air do not have operating costs, but efficiency penalties instead, as the combustion is modified to a less efficient and less NO_x producing state. Flue gas recirculation (especially used for liquid or gaseous fuel combustion) faces additional pump costs for gas circulation and efficiency penalties.

Operating costs in a SNCR system are ammonia or urea consumption costs and occurring pressure losses (acc. to LCP-BRef ~ 4-10 mbar, depending on the no. of catalyst layers).

SCR face ammonia or urea consumption costs, comparably higher pressure losses, energy consumption for sootblowing and catalyst replacement costs. For coal-only fired power plants, catalyst lifetimes have increased during the last decades. According to EGTEI experts, one layer has to be regenerated every three years and a catalyst layer can be regenerated up to 7 to 8 times. Regeneration costs are expected to be around 50% of the purchasing costs for new layers. Firing practices such as biomass co-firing reduce the catalyst lifetime (1-2 years), hence annual regeneration and replacement costs are higher.

The use of urea or NH_3 as reducing agent may lead to emissions of unreacted NH_3 (slip). Actual slip depends on operating conditions, especially reagent / flue gas mixing, catalyst activity and amount of reagent injected. In Germany, ammonia emissions are regulated at 5 ppm max[9]. Additional NH_3, restrictions arise due to the fact that salability of flyash decreases with growing ammonia concentration. Due to this effect, experts see ammonia emissions restricted at 2 ppm[10]. Reagent consumption as implemented in RAINS represents a good estimate.

SO_2 abatement

The largest part of FGD operating costs are sorbent (e. g. lime, limestone, CaOH, $NaHCO_3$) costs. Especially wet FGDs face high electricity costs due to pumping and pressure losses (acc. to LCP BRef 20-30 mbar). Overall, the BRef states an overall energy consumption of 1-3% of installed electrical capacity. No operating data for further desulphurisation techniques could be collected.

Wet systems have water treatment costs. Reagent consumption as implemented in RAINS represents a good estimate. If FGDs produce salable gypsum, revenues may arise. Other systems, such as semi-dry sorption with CaOH have landfilling costs. Collected data showed operating expenses for wet FGDs at 1

[8] Thomas Riepe: „Elektrofilter und Gewebefilter für kohlegefeuerte Kraftwerke im Vergleich“, held at: 4. Conference on „Grundlagen, Betriebserfahrungen, Optimierungsmaßnahmen und Sonderverfahren für Rauchgasreinigungsanlagen“, Essen (Germany), 2008.
[9] Ulrich Förstner: „Umweltschutztechnik“, 2008.
[10] EPRI: „Achieving NO_x compliance at Least Cost: A Guide for Selecting the Optimum Combination of NO_x Controls for Coal-Fired Boilers”, 1998.

to 4% of total investment per annum at 4 different sites[11]. As a side effect, wet FGDs abate HCl, HF, SO_3 and dust as well. Sour gas removal rates can be > 90% acc. to the BRef.

[11] Umweltbundesamt Österreich: „Entschwefelungstechnologien – die Situation in Österreich", 2002.