



Assessment of the benefits and costs of the potential application of the IPPC Directive (EC/96/61) to industrial combustion installations with 20-50 MW rated thermal input

Contract Ref : 070307/2007/463616/MAR/C4

Final Report

**Report to European Commission
DG Environment.**

ED05553
AEA/ENV/R/2481/Issue 2
October 2007



Title	Assessment of the benefits and costs of the potential application of the IPPC Directive (EC/96/61) to industrial combustion installations with 20-50 MW rated thermal Input – Final Report
Customer	European Commission DG Environment
Customer reference	070307/2007/463616/MAR/C4
Confidentiality, copyright and reproduction	This report is the Copyright of AEA Technology plc and has been prepared by AEA Technology plc under contract to the European Commission. The contents of this report may not be reproduced in whole or in part, nor passed to any organisation or person without the specific prior written permission of the Commercial Manager, AEA Technology plc. AEA Technology plc accepts no liability whatsoever to any third party for any loss or damage arising from any interpretation or use of the information contained in this report, or reliance on any views expressed therein.
File reference	ED05553
Reference number	AEA/ENV/R/2481/Issue 2

AEA Energy & Environment
Gemini Building
Fermi Avenue
Harwell
Didcot
Oxon
OX11 0QR

tel: +44 (0)870 190 6575
fax: +44 (0)870 190 6318

AEA Energy & Environment is a business name of AEA Technology plc.

AEA Energy & Environment is certificated to ISO9001 and ISO14001.

Author	Name	Robert Stewart Wouter Nijs (VITO)
	Reviewed by	Name
	Signature	
	Date	

Executive Summary

The overall objective of this contract is to support the Commission within the framework of the review of the Directive 96/61/EC concerning Integrated Pollution Prevention and Control (IPPC) to provide a robust assessment of the costs and benefits of extending the scope of the IPPC Directive to include combustion installations in the range 20-50 MW_{th}.

The current IPPC Directive includes the regulation of combustion installations >50 MW_{th} in energy industries. Directive 2003/87/EC on establishing a scheme for greenhouse gas emission allowance trading (EU ETS) includes combustion installations >20 MW_{th}. This project analyses the costs and benefits of adopting thresholds similar to those under EU ETS installation under the IPPC regime.

20-50 MW_{th} combustion installations may already be regulated under the IPPC Directive if they are directly associated to another activity regulated under the IPPC Directive. In addition, national or regional regulations implemented by Member States may include 20-50 MW_{th} installations.

The project involved gathering data on combustion installations (emissions, abatement measures and their costs, emission reduction potential) and existing emission legislation in selected Member States. This information was then extrapolated to the other Member States and the whole EU. A baseline emission scenario was developed and then compared with several potential emission control scenarios. The emission control scenarios represent a range in emission control levels such as application of Large Combustion Plant Directive emission limits, BAT AELs for large combustion installations, the most stringent national regulations and a maximum feasible reduction scenario.

A 20-50 MW_{th} installation mostly consist of different combustion units whose capacity is usually significant smaller than the one of the whole installation. More than half of the combustion units have a capacity smaller than 3 MW_{th}. The analysis shows that despite low load factors evident for small combustion installations and the large number of small combustion units (<3 MW_{th}); the environmental and health benefits of all the selected reduction measures outweigh the compliance and administrative costs.

Table of contents

1	Introduction	1
2	Methodology	2
2.1	Overview	2
2.2	Modelling methodology	3
2.3	Approach to characterising 20-50 MW _{th} installations in selected Member States	4
2.4	Estimates of 20-50 MW _{th} installations in selected and other MS	7
2.5	Approach to assessing costs and benefits	9
3	Summary of data used in analysis	11
3.1	Data collection issues	11
3.2	Overview of 20-50 MW _{th} Installations in European Union	11
3.3	Installation data for selected Member States	13
3.4	Overview of technologies	16
3.5	Pollutant emissions	20
4	Emission control scenarios	23
4.1	Business as usual (Baseline)	23
4.2	LCPD Scenario (existing plant)	23
4.3	LCPD Scenario (new plant)	24
4.4	LCP BREF Scenario	24
4.5	Stringent National Emission Limit Value Scenario	25
4.6	Maximum Feasible Reduction	26
4.7	SO ₂ assumptions for all scenarios	26
5	Analysis	28
5.1	Summary of emissions under the various scenarios	28
5.2	Cost Benefit Analysis	30
6	Conclusions	34
7	References	35

Appendices

- Appendix 1: Data template
- Appendix 2 : Preliminary data for Flanders region of Belgium
- Appendix 3 : Completed data templates for selected Member States
- Appendix 4 : Member State emission limit values
- Appendix 5 : Business as Usual reference scenario data
- Appendix 6 : Uncertainty analysis of scenarios
- Appendix 7: Defra Operators' and regulators' costs

1 INTRODUCTION

The overall objective of this contract is to support the Commission within the framework of the review of the Directive 96/61/EC concerning Integrated Pollution Prevention and Control (IPPC) to provide a robust assessment of the costs and benefits of extending the scope of the IPPC Directive to include combustion installations in the range 20-50 MW_{th}¹.

The current IPPC Directive includes regulation of combustion installations >50 MW_{th} in energy industries. Directive 2003/87/EC on establishing a scheme for greenhouse gas emission allowance trading (ETS) includes combustion installations >20 MW_{th}. This project analyses the costs and benefits of adopting EU ETS installation thresholds under the IPPC regime. 20-50 MW_{th} combustion installations may already be regulated under the IPPC Directive if they are directly associated to another activity regulated under the IPPC Directive. In addition, national or regional regulations implemented by Member States may include 20-50 MW_{th} installations.

In brief, the project tasks involved:

- gathering data on combustion installations (emissions, abatement measures and their costs, emission reduction potential) and existing legislation in selected Member States;
- developing potential emission control scenarios for cost benefit analysis;
- undertaking analysis of costs and benefits for selected Member States and, by extrapolation, for the other Member States and the EU as a whole;

This Final Report describes how AEA Energy & Environment and our project partners (VITO and AEA Mediu srl) have undertaken the project, the findings of the data collection task and the cost benefit analysis of the emission control scenarios.

¹ MW_{th} represents net thermal input.

2 METHODOLOGY

2.1 Overview

The tasks, and their inter-relationships are summarised in Figure 2-1 below. The key methodology steps were as follows:

- Identify data to characterise 20-50 MW plant across the EU
- Develop a reference case for the analysis – to assess the impact of extending the IPPC Directive to cover the above plant
- Analyse a set of scenarios to assess the costs and benefits of including 20-50 MW plant
- Estimate costs and benefits, and conclude the impact of extending this Directive

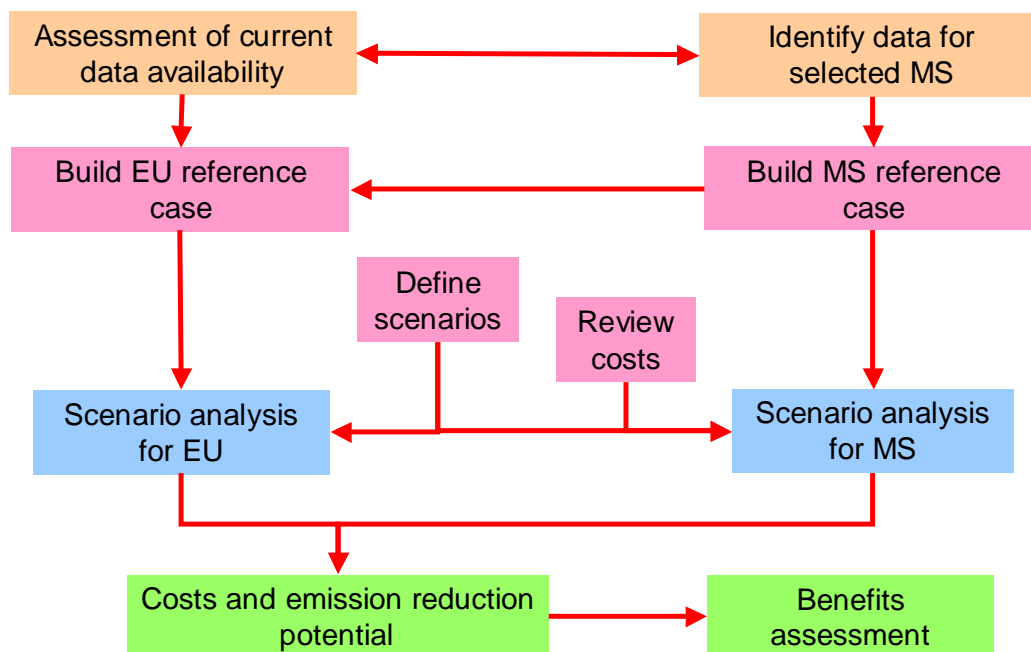


Figure 2-1 Schematic of the project tasks

The key issue that underpins this whole assessment is that of data availability. In the first instance, information in published reports was used to assess the range of types of installation, legislation and emissions. Data were also gathered from selected Member States. Information was supplemented and updated as necessary by contact with regulatory and environmental authorities in the selected Member States.

There were several broad areas of information gathering:

- *Characterising the 20-50 MW_{th} installations* – numbers, total capacity, permitted installation capacity, combustion unit type, unit capacity, unit numbers, fuel type and fuel use
- *Current regulation* – under IPPC or national permitting regimes
- *Current emission levels* – to assess NO_x, SO₂ and PM emissions
- *Potential for emission abatement* – the techniques applied, including their emission reduction potential and their costs

Profiles of 20-50 MW_{th} combustion plant in selected Member States were developed from the information gathered to allow development of generic Member State or EU profiles.

For the selected Member States, the EU ETS national authority (or authorities) were contacted to obtain more detail of installations and associated combustion units. Permit application databases (where available), EU ETS National Allocation Plans (NAPs) and the Community Independent Transaction Log (CITL) registry data were also used to develop details of installations (size, technology, fuel, combustion unit numbers). A data template was developed for completion by the Member States (see Appendix 1).

The information gathered was used to develop a reference or baseline emission scenario for the 20-50 MW_{th} combustion installations. A range of potential emission control scenarios were then developed and a model was developed to analyse the costs and benefits of applying the different emission control scenarios.

2.2 Modelling methodology

An Excel-based tool was developed based on data collected for Member States' installations. The model includes a reference or baseline scenario of all EU-27 countries which provides the current emissions and controls. The potential change in emissions from the baseline arising from an alternative emission control scenario is then calculated. Based on comparison of each emission control scenario with the reference scenario, the model estimates:

- The compliance cost and the administrative costs for operators and regulators going from the reference scenario to emission control scenario X
- The reduction of emissions and external costs (avoided damage costs) related to it.

With these basic data, a “net benefit” was calculated by subtracting all costs from the external costs of the emissions avoided (called benefit). A general map of the project activities to develop the CBA is shown in the figure below.

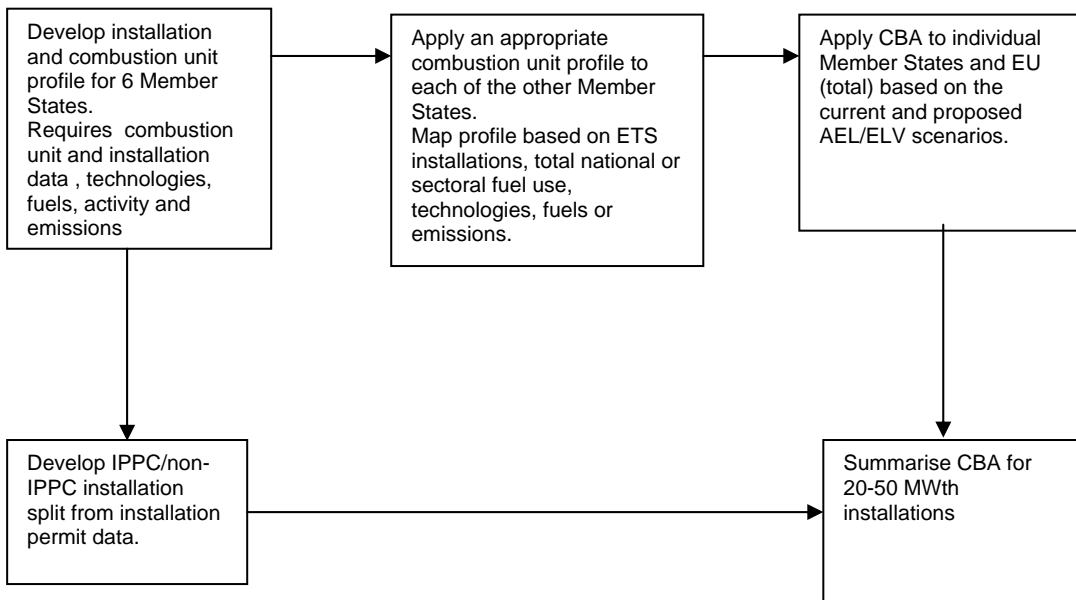


Figure 2-2 Flowchart of modelling activity

The model identifies the cheapest options at given abatement levels. A least cost solution is guaranteed because the cheapest relevant techniques or control measures for the cost calculations for the different scenarios are selected outside the model. This selection is based on the emission limit values and a list of reduction techniques for every pollutant.

The model partially runs in multivariant mode (that is for all pollutants at the same time). Some reduction techniques have an effect on more than one pollutant. In the model used for the scenarios, this effect has been taken into account by lowering the cost of PM reduction in the more stringent scenarios.

To assess the uncertainties, a further spreadsheet model was developed. The methodology involved applying an uncertainty range to some parameters using Monte Carlo Analysis. Typically, in this type of uncertainty exercise, 100,000 iterations are needed to develop the overall uncertainties for the scenarios. Parameters for which major uncertainties were identified included:

- Emission factors of the reference case
- The external costs of avoided emissions
- The Sulphur-content of coal
- The load hours for engines

Other uncertainties are implicitly taken into account through the definition of the scenarios (see chapter 4). Costs of emission reduction techniques are linked to the required emission reduction from the baseline scenario.

It was found that the assumption on the external costs of avoided emissions has a significant impact on the calculated net benefit. In most scenarios, this assumption contributes to more than 50% to variance of the result (although this depends on the scenario in question - see chapter 5.2.2 and appendix 6).

2.3 Approach to characterising 20-50 MW_{th} installations in selected Member States

To undertake an assessment of the costs and benefits, information on 20-50 MW_{th} installations in Member States was collected. The approach was to identify a high level of detail for selected Member States on these types of installations and hence develop Member State profiles, which could then be applied to other Member States. Profiles that were applied to the other Member States were scaled according to installation numbers, fuel consumption data and carbon emissions.

The Member States selected for detailed analysis are shown in Table 2-1. They represent a range of different situations with regard to the use of small combustion installations and fuels. In addition, they represent different geographical areas of Europe and, are a mix of new and more established Member States.

Table 2-1 Selected Member States for this analysis

Member State	ETS Installations (EEA, 2007)			Contact organisations
	Total	Total E1 >20MW _{th} Energy	E1 20-50MW _{th} Energy	
Belgium	310	207	150	Environment, Nature and Energy Department of the Flanders Region Vlaamse Milieumaatschappij, VMM Benchmark verification bureau, Environment department of the Walloon and Brussels region.
Finland ²	600	284	124	Energy Market Unit Ministry of Environment
Poland	500 (incomplete)	381	253	Ministry of the environment; national ETS administrator (Kashue) Contacts from VITO Twinning or Taiex projects
Romania	- (no data)	-	-	Ministry of energy and water management
Slovenia	98	67	32	Environment Agency Contacts from VITO Twinning or Taiex projects
UK	779	694	387	Environment Agency for England & Wales (lead authority for ETS permitting); Defra; DTI (responsible for offshore installations)

² Originally Italy, a southern European Member State, was selected for detailed assessment but initial contacts were unsuccessful and Finland was substituted.

The priority data requirements for this analysis for selected Member States are listed below:

- Number of installations, total capacity in 20-50 MW_{th} range disaggregated by sub-ranges where possible
- Type and quantities of fuel used in the installations
- Extent of coverage under national permitting schemes (IPPC or similar)
- Applied ELVs for installations
- Current emissions of Particulate Matter, NO_x and SO₂ to air from installations (CO₂ and Volatile Organic Compounds for the reference case too)
- Types and penetration of abatement equipment on installations

In addition we sought to gather the following data to provide further detail on the installations and combustion plant:

- Number of combustion units in installations
- Installation carbon dioxide or carbon emissions (in the absence of fuel data, these emissions provide a surrogate for fuel consumption)
- Type of combustion technology – for example boiler/furnace type, gas turbine or engines.
- Emission limits or achievable emission levels
- Load factor for plant
- Understanding of the estimates of the 20-50 MW_{th} group within ETS as reported in (EEA, 2007).

This level of detail was necessary to enable characterisation of 20-50 MW_{th} installations in the selected Member States (and hence apply across the EU). Understanding the potential for emission reductions requires knowledge of the combustion plant technologies and operation. To aid data collection on combustion installations a template was developed for distribution to the selected Member States (see Appendix 1).

In theory, all these data are available but in many instances the information can only be found within permits, permit applications or other relevant documents and are effectively inaccessible without expending resources beyond the scope of this project.

The data collection sources for the selected Member States and the rest of the EU are outlined in Table 2-2.

Where installation and combustion unit data were not available in an accessible format for one or more of the six selected Member States, we applied assumptions about plant populations developed from the review of information and the data obtained from those Member States with more accessible data. For example carbon emissions under ETS and sectoral (industrial combustion) energy data from GAINS were used (IIASA, Gains) to determine average energy use in installations. The aim was to use such aggregated data amended or 'calibrated' from installation-specific data from the chosen Member States.

For the Member States which were not part of the detailed data gathering, distinguishing 20-50 MW_{th} installations was based on the EEA report data, and using the data from the detailed Member State profiles.

Table 2-2 Data sources

Data	Sources
All Member States	
ETS Installations by sector	EEA 2007
ETS Installations 20-50 MW _{th}	EEA 2007
IPPC Combustion installations >50 MW _{th}	IPPC (EPER)
ELV or BAT AEL	CAFE (AEAT 2004), LCP BREF, IPPC review (IEEP)
CO ₂ Emissions	EEA 2007
Fuel use in sectors	Eurostat/GAINS
Abatement techniques	VITO model, CAFE (AEAT 2004), IEEP, LCP BREF
Costs	VITO model (abatement), IPPC review (permitting)
Selected Member States	
20-50 MW _{th} combustion installation numbers and capacity	Member State ETS Data
Combustion technology	ETS installation database
Combustion unit size	ETS installation database
Fuel use	ETS database (installation), GAINS
Emissions	Member State ETS Data, ELVs, Corinair emission factor guidebook

A key issue to assess the overall impact of extending the IPPC Directive is the determination of the proportions of combustion installations in the range 20-50MW_{th} which are already regulated under IPPC (or similar BAT based regimes) and those which are not. In this report, the EU ETS installations which are part of an IPPC installation were identified for some of the selected MS, but an EU extrapolation was not undertaken.

Although the IPPC Directive does not explicitly cover this capacity range under Annex I, some 20-50 MW_{th} (and smaller) installations or units will already be subject to application of the IPPC Directive if they are directly associated with other IPPC activities (e.g. chemical sector, iron and steel, pulp and paper) which are explicitly listed in Annex I of the IPPC Directive and therefore form part of the same overall "installation" (see definition of installation in the IPPC Directive).

The categorisation of ETS activities does not cover all IPPC sectors or sector activities (see Table 2-3) and ETS energy installations may include facilities which may be directly associated with (for example) installations which are within the chemicals activities listed in the IPPC Directive. It would therefore be an over-simplification to consider that all the ETS 20-50 MW_{th} plant are unregulated under IPPC.

Note that while some installations in the 20-50 MW_{th} range are directly associated activities and already in theory covered by the IPPC Directive, extending the threshold of the IPPC Directive may lead to further emission reduction from these plant. The large combustion plant BREF does not contain BAT information for combustion installations <50 MW_{th}. Hence, where there are directly associated 20-50 MW_{th} installations, the Member States' regulators will apply a range of emission controls they consider appropriate. The extent of emission controls can be assessed for the six selected Member States by comparison of applied emission controls with the scenarios. For the EU, the assessment can be developed based on the range of controls applied by the Member States.

Table 2-3 Mapping of ETS and IPPC Annex 1 activities

IPPC		ETS
1	Energy industries	Energy activities
1.1	Combustion installations > 50 MWth	Combustion installations > 20 MWth
1.2	Mineral Oil and Gas refineries	Mineral Oil refineries
1.3	Coke ovens	As IPPC
1.4	Coal gasification and liquefaction plants	No activities listed
2	Metal production and processing	Production and processing of ferrous metals
2.1	Metal ore roasting or sintering	As IPPC
2.2	Pig iron or steel production >2.5 tph	As IPPC
3	Mineral industry	Mineral industry
3.1	Cement clinker producing installations >500 tpd (50 if non-rotary kiln) Lime producing installations > 50 tpd	As IPPC
3.3	Glass (fibre) >20 tpd	As IPPC
3.4	Melting mineral substances >20 tpd	No activities listed
3.5	Ceramics >75 tpd and/or kiln >4 m ³ and >300 kg/m ³ setting density per kiln	As IPPC
4	Chemical industry	No activities listed
5	Waste management	No activities listed
6	Other activities	Other activities
6.1	(a) Pulp from timber or other fibrous materials (b) Paper and board >20 tpd	As IPPC

Note: Not all IPPC sub sectors shown.

The analysis needs to address the range of combustion **units** (e.g. individual boilers, furnaces etc) within Member State installations, as this is the level at which abatement technologies may be applied. For input into the model, combustion units were aggregated by different categories:³

- According to unit capacities (0-3 MW_{th}, 3-15 MW_{th} and >15 MW_{th})
- According to combustion technology (Boiler/furnace, gas turbine and engine)
- According to fuel (solid, liquid, gas, biofuel and other)

2.4 Estimates of 20-50 MW_{th} installations in selected and other MS

Extending the model to allow analysis of all Member States and the whole EU required development of combustion unit profiles for each Member State. Profiles for the selected Member States were developed from the completed data templates (Appendix 3). In some instances the templates were further completed by the project team from data supplied by the Member State. As mentioned in paragraph 2.3, the combustion units were aggregated by different categories. The combustion unit profile for a MS is an overview of the numbers of combustion units in the different categories. An example for Slovenia is in Table 2-4. The total number of combustion units in Slovenia in the category 20-50 MW_{th} is 165. The total for every capacity category is respectively 85, 63 and 17.

³ The preliminary work on the Flanders region of Belgium which underpins the use of the three combustion unit categories is provided in Appendix 2.

Table 2-4 Combustion unit profile of Slovenia

20-50 MWth installations, 0-3 MWth					
	Gaseous fuels	Liquid fossils	Biomass	Solid Fuels	Other
Boiler	15	6	3		
Furnace	43				1
Gas turbine					
Engine	1	16			
Total					85
20-50 MWth installations, 3-15 MWth					
	Gaseous fuels	Liquid fossils	Biomass	Solid Fuels	Other
Boiler	49	5		2	
Furnace	5			2	
Gas turbine					
Engine					
Total					63
20-50 MWth installations, 15-50 MWth					
	Gaseous fuels	Liquid fossils	Biomass	Solid Fuels	Other
Boiler	11			1	
Furnace	4		1		
Gas turbine					
Engine					
Total					17

What is the average installation capacity of the selected MS?

The installation capacity is the sum of the capacities of all the different combustion units. The distribution of all installation capacities in a Member State determines an average installation capacity. In the data template completed by the selected MS, no information was asked for the capacity of all installations. In place, detailed data was asked on combustion units. Using the knowledge from the Flanders case, the average installation capacity can be derived from the combustion unit profile. The aggregated capacity of an average installation in Slovenia is 32.6 MW_{th} when using capacities of 0.5, 10 and 25 MW_{th} for the three combustion unit categories respectively. We know from the Flanders case and from theory on the distribution of all installation capacities that the average installation capacity is close to 35 MW_{th}. This indicates that data is broadly consistent.

What is the average combustion unit profile of a selected MS?

In order to extrapolate the data from selected MS to others with less detailed data collected, it is important to define average installation characteristics such as the average number of combustion units per installation and the average installation capacity.

From the combustion unit profiles of selected MS, we developed an average combustion unit profile. This average of all selected MS combustion profiles is used in the extrapolation. It is a distribution of the number of combustion units for an ETS installation in a selected category (see Table 2-5).

Table 2-5 - Average selected MS installation profile

Combustion unit capacity, MW _{th}	0-3	3-15	> 15
Average capacity, MW _{th}	0.5	10	25
Average number of combustion units	65%	30%	5%
Average energy use ⁴	7%	65%	28%

⁴ Based on average capacity and average number of combustion units, thus assuming identical load hours for every category.

The main conclusions of the work on estimating average values from the selected Member States templates are:

- Average installation capacity can be calculated from the average combustion profile. The average installed capacity of installations is around 33 MWth⁵.
- The average number of combustion units per installation is eight

The average profile was applied to the other (non-selected) Member States. The following Member State specific parameters were used to make them more representative of the MS:

- Number of installations;
- Identification of key fuels;
- Specific combustion technologies and ELVs

The same distribution of the average profile on number of units, capacity and energy use is applied to the data on installations as given in ETS or other sources. The data on the number of installations comes from (EEA 2007) and is the most important parameter, although for some countries, the identification of the key fuel influences the emission estimates significantly. For each scenario, the assumption on average load hours (1000 or 3000 hours) is taken for every Member State. The benefits and costs of each Member State were then determined from the reference case based on the emission reductions and the number of installations likely to be affected by extending the IPPC threshold and, the current legislative framework (where known).

For building the other MS profiles, no assumptions were made on whether or not a "de minimis rule" (excluding combustion units below a certain capacity, e.g. 3 MW) had been applied for the purpose of the ETS as this could not be fully assessed from the data available. It looked as if for ETS, UK has not applied a de minimis rule, while Belgium has. For Romania the data suggest that a de Minimis has been applied but they were in the early process of permitting.

2.5 Approach to assessing costs and benefits

2.5.1 Emission estimates and legislation

Emission estimates from 20-50 MW_{th} installations was based on information on regulatory emission limit values (ELVs), the large combustion plant (LCP) BREF, national inventories, emission factors and other published guidance (for example Member State regulatory guidance on combustion activities). The LCP BREF has limited data on small combustion units and the project team's own resources supported by a literature review were used to assess current and achievable emission levels. Published literature were used to provide a summary of emission estimates, emission legislation and emission limit values applied for small combustion installations, updated as necessary by contact with regulatory authorities.

2.5.2 Assessment of compliance costs

The database of the Environmental Costing Model (ECM) developed by VITO was used to assess costs to reduce emissions of SO₂, NO_x and PM for the selected scenarios (VITO 2006). ECM is a model to (i) determine the costs of environmental policy and (ii) contribute to more efficient environmental policy by indicating how environmental targets can be reached in a cost effective way. Most technology and abatement costs data used came from the ECM model. Note that this is a separate model database to that used in the GAINS model.

⁵ For the data on the MS, there are more installations in the 20-35 range MWth than in the 35-50 MWth range and thus the average is somewhat lower than 35 MWth. On the other hand, in case a de minimis rule is applied by MS, the average installation capacity will be higher. As a rule of thumb, one can conclude that all MS will have an average installation capacity between 30 and 40 MWth.

It was not necessary to distinguish the installations or sectors in the model as the combustion unit technologies in different sectors are generally similar. Typically the differences concern use of atypical fuels (for example derived fuel gases, coke or process by-products). For this analysis we have assumed that differences between sectors are generally in larger installations (that is where the installation size is greater than 50 MW_{th}) and that, for the purpose of this analysis, smaller installations use the same fuel types and combustion technologies (although note that differences between Member States' fuel use is recognised). The technical information on the combustion units is sufficient for determining the cost of reduction measures. The costs of compliance across sectors are then effectively the costs of reducing emissions from the baseline or reference scenario. It is clearly important that emissions in the reference scenario reflect actual emissions and applied emission limits.

The ECM database of abatement measures with their associated emission reduction potential and annual costs are translated into an emission reduction cost (€/tonne). From the figures it can be seen that this is dependent on the load hours assumed. This is because a reduction technique has a fixed investment cost irrespective of the number of load hours.

The compliance costs of each scenario were developed assuming a range of technologies applicable to the pollutant emission factors developed for each scenario.

2.5.3 Assessment of operators' administrative costs

The costs for administration are related to the number of installations⁶. The cost for permitting an installation were developed assuming an average one-off permit application and annual costs which were taken from UK data (Defra, 2007). See appendix 7 for the detailed data from the Defra report.

2.5.4 Assessment of regulators' cost

Regulator costs were taken from UK data for permit applications and annual subsistence. The UK regulatory costs are essentially covered by application and subsistence fees and these were used in the absence of data on regulator costs. See appendix 7 for the detailed data from the Defra report.

2.5.5 Benefits analysis

The benefits analysis was based on the cost damage per tonne of pollutant functions developed under the CAFE programme⁷ (AEA, 2005). These damage per tonne values provide an estimate of the impacts on health and agricultural crops. Functions are available for SO₂, NO_x, and PM₁₀, and are specific to different Member States.

A range of damage costs was applied based on the range of monetary values from the CAFE analysis - using the low (median value of a life year - VOLY) and high (mean value of statistical life - VSL) values for 2010.

⁶ Administrative costs increase even if national legislation already exists or if impact on emissions of new legislation is limited.

⁷ Damages per tonne emission of PM_{2.5}, NH₃, SO₂, NO_x and VOCs from each EU25 Member State (excluding Cyprus) and surrounding seas. EC service contract ENV.C.1/SER/2003/0027, AEA Technology, March 2005.

3 SUMMARY OF DATA USED IN ANALYSIS

3.1 Data collection issues

Two Member States (Finland and Italy) initially contacted for the project were unable to provide any data. A complete dataset from Slovenia was available although this country has comparatively few installations. The information obtained for Romania reflects that this country is in the process of implementing EU ETS; although data for 20-50 MW_{th} installations were obtained, data are limited and the number of installations may be incomplete. Poland provided some data but due to the large number of regional administrative bodies for EU ETS in Poland (particularly for 20-50 MW_{th} installations), data were limited and difficult to collate. The data for Belgium and UK were very detailed but for these countries, the issue of access to these data proved difficult.

As with previous studies, the data needs of the project proved difficult to fulfil within the project timescales. Despite this sufficient data were obtained to establish a combustion unit profile for 20-50 MW_{th} combustion installations, allowing for an analysis of the cost and benefits of extending the IPPC Directive to these installations. The uncertainty analysis takes into account the uncertainty of using the limited data available.

3.2 Overview of 20-50 MW_{th} Installations in European Union

The numbers of 20-50 MW_{th} installations in EU ETS as reported by Member States for 2005 and 2006⁸ are summarised in Table 3-1. There are some large changes in the relevant installation numbers for several Member States between 2005 and 2006, which probably reflects greater understanding of the installations in the later survey. The Commission also issued guidance⁹ on installation definition in 2005 which may have helped to harmonise installation categories. The data represents EU(-25) ETS 'E1' 20-50 MW_{th} combustion installations and hence may not provide a measure of combustion installations in other ETS sectors or those combustion facilities which are directly associated to IPPC but are not ETS activities.

Table 3-1 illustrates that the 20-50 MW_{th} combustion installations represented less than 3% of EU-25 ETS CO₂ emissions in 2005. Some plant are also operating with a high degree of redundancy (Table 3-2); that is the installed combustion plant capacity exceeds 20 MW_{th} but the actual annual average load (an indicator for the load factor) is typically lower than 10 MW_{th} and in many instances less than 5 MW_{th}. The average heat input and estimated installation running hours analysis also indicates possible issues with EU ETS data from Slovakia.

In Table 3-2, EEA data on the number of 20-50 MW_{th} installations and on CO₂ emissions of those installations is shown. From these data, a range of annual fuel input per installation is derived in column 3 and 4 assuming coal and gas as fuels. In the same way, average input heat rate and equivalent annual hours are calculated. The equivalent annual hours is the hours the installation is working assuming a capacity of 33 MW_{th} and assuming full capacity use. Most of the load hours in Table 3-2 are smaller than 3000 hours.

⁸ Note that these represent the reporting year (Member States are required to provide reports by 30 June each year) and data refer to trading during 2004 and 2005.

⁹ COM(2005)703 final. Further guidance on allocation plans for the 2008 to 2012 trading period of the EU Emissions Trading Scheme. European Commission, 22 December 2005.

Table 3-1 Summary of 20-50 MW_{th} combustion installations and emissions (EEA 2006a, EEA 2007)

Member State	2005 20-50 MW _{th} combustion Installations Number	2006				
		20-50 MW combustion Installations			CO ₂ Emissions	
		Number	Share of E1 installations, %	Share of total National ETS Installations %	t CO ₂ eq	Share of total national emissions %
Austria	49	47	43	24	485744	1.5
Belgium ¹	150	108	52	45	1395656	3.5
Cyprus		0	0	0	0	0
Czech Republic	121	-	-	-	-	-
Denmark ³	244	237	43	62	1826000	6.9
Estonia		21	57	50	372166	3
Finland	122	124	44	22	846738	2.6
France ²	340	340	53	31	4200000	2.8
Germany ²	680	665	54	36	9323545	1.9
Greece ^{2,3,4}	8	10	24	7	249647	0.4
Hungary		71	47	30	1103424	4.2
Ireland	53	55	54	50	580675	2.6
Italy	269	257	46	49	3589000	2.5
Latvia	36	33	40	36	657151	23
Lithuania ³	35	35	42	38	323379	4.9
Luxembourg	6	-	-	-	-	-
Malta	0	0	0	0	0	0
Netherlands	59	62	38	30	2196000	2.7
Poland		253	66	40	4981058	2.8
Portugal	39	29	38	12	918668	2.5
Slovakia	103	87	61	50	10983622	43.5
Slovenia	32	32	48	33	324769	3.7
Spain	2	113	45	14	6582238	3.6
Sweden	65	164	37	20	439551	2.3
United Kingdom	450	387	56	54	2426374	1
Total EU-25	2936	3130	49	34	53805405	2.9

Notes (2006 data)

1. Calculation of shares excludes Brussels
2. Approximate values only
3. Based on CITL data at 31/10/06
4. Now data of 16/11/2007 from the ministry of environment shows 12 installations. There are 7 in the electricity sector, 4 in the industrial and 1 in the non-industrial sector with respectively 57,12 and 36 units and with respectively 8,3 and 36 units per installation.

Table 3-2 – Annual heat input and operating hours of 20-50MW_{th} installations in 2006

Member State	Number of 20-50MW _{th} installations (EEA 2007)	Annual CO ₂ emission, t CO ₂ eq (EEA 2007)	Range of annual fuel input per installation ^[note 1] , GJ		Range of average input heat rate, MW _{th}		Equivalent annual hours ^[note 2]	
			Min (coal)	Max (gas)	Min (coal)	Max (gas)	Min (coal)	Max (gas)
Austria	47	485744	111129	184553	3.52	5.85	935	1553
Belgium	108	1395656	138954	230763	4.41	7.32	1170	1942
Cyprus	-	-	-	-	-	-	-	-
Czech Republic	-	-	-	-	-	-	-	-
Denmark	237	1826000	82846	137583	2.63	4.36	697	1857
Estonia	21	372166	190561	316468	6.04	10.04	1604	2664
Finland	124	846738	73425	121938	2.33	3.87	618	1026
France	340	4200000	132827	220588	4.21	6.99	1118	1857
Germany	665	9323545	150757	250364	4.78	7.94	1269	2107
Greece ^[note 4]	10	249647	268438	445798	8.51	14.14	2260	3753
Hungary	71	1103424	167109	277521	5.30	8.80	1407	2336
Ireland	55	580675	113524	188531	3.60	5.98	956	1587
Italy	257	3589000	150161	249375	4.76	7.91	1264	2099
Latvia	33	657151	214125	355601	6.79	11.28	1802	2993
Lithuania	35	323379	99348	164989	3.15	5.23	836	1389
Luxembourg	-	-	-	-	-	-	-	-
Malta	-	-	-	-	-	-	-	-
Netherlands	62	2196000	380853	632488	12.08	20.06	3206	5324
Poland	253	4981058	211699	351571	6.71	11.15	1782	2959
Portugal	29	918668	340626	565682	10.80	17.94	2867	4762
Slovakia	87	10983622	1357511	2254438	43.05	71.49	11427	18977
Slovenia	32	324769	109129	181233	3.46	5.75	919	1526
Spain	113	6582238	626343	1040177	19.86	32.98	5272	8756
Sweden	164	439551	28819	47861	0.91	1.52	243	403
UK	387	2426374	67416	111959	2.14	3.55	567	942
Overall	3130	53805405	238838	396642	7.57	12.58	1540 ^[note 3]	2560 ^[note 3]

Notes :

1. The analysis provides a range of energy input derived from the reported annual CO₂ emission and the range of CO₂ emission factors for different fuels and assumes CO₂ emission factors of 93 Tc CO₂/TJ (for coal and assumed to be equivalent minimum heat input) and 56 Tc CO₂/TJ (for natural gas and assumed to be equivalent to the maximum heat input) with an oxidation factor of 1.
2. Assumes an average installation capacity of 33 MW_{th} (based on preliminary work for Flanders Region).
3. Excludes Slovakia, whose average hours per year are greater than 8760.
4. Diesel engines in Greece for electricity production have average load hours between 1370 and 2830.

3.3 Installation data for selected Member States

3.3.1 Installation and combustion unit numbers

Table 3-3 provides numbers and sizes (where available) of installations in the selected Member States derived from the data provided by the Member States for this project.

Table 3-3 – Numbers and installed capacities of 20-50 MW_{th} combustion installations

Member State	20-50MW _{th} installations		No. of installations in size range		
	EEA 2007	This project	20-30 MW _{th}	30-40 MW _{th}	40-50 MW _{th}
Belgium	108	84	27 ¹⁰	33	24
Poland	253	388	-	-	-
Romania	-	46	26	14	6
Slovenia	32	32	-	-	-
United Kingdom	387	413	200	125	88

¹⁰ Extrapolation on Flanders data.

In a number of instances the estimated numbers of 20-50 MW_{th} installations are different to the estimates in the EEA report and this reflects different time periods (installations have closed, or new entrants have joined the scheme or the scheme is in the process of implementation). For the UK, a number of installations which are in a pre-existing national emission trading scheme and officially outside the EU ETS during the EEA survey (but joining in 2007) have been included. For Belgium, the reason for the difference is believed to be that some installations >50 MW_{th} may have been included in the 20-50MW_{th} installations reported in the EEA questionnaire.

The emission characteristics, costs of abatement and other factors are dependent on the size of the combustion units. A number of Member States apply size-dependent pollutant emission limit values to combustion units but there is no commonly-accepted capacity classification. Preliminary work on the combustion installations in the Flanders region of Belgium (Appendix 2) indicated that the combustion units in an installation could be conveniently categorised in three size ranges:

- 0-3 MW_{th}
- 3-15 MW_{th}
- >15 MW_{th}

Table 3-4 – Combustion unit profile for Member States

Member State	20-50MW _{th} installations		No. of combustion units in size range			
	EEA 2007	Member State	0-3 MW _{th}	3-15 MW _{th}	>15 MW _{th}	Total
Belgium	108	84	423	217	26	666
Poland	253	388	-	-	-	-
Romania ^[note 1]	-	46	23	107	14	144
Slovenia	32	32	85	63	17	165
United Kingdom ^[note 1]	387	413	3989	1228	72	5289

Notes :

1. Combustion unit figures include estimates of unit numbers where no data given but multiple combustion units indicated within ETS data; unless indicated otherwise in the ETS databases the numbers assume 3 boilers per installation (from expert judgment based on 'typical' industrial utility installations) but with larger unit numbers assigned where indicated by notes within databases on average capacity and installation capacity (for example if the comments in the database indicated presence of two larger combustion units and multiple boilers <100 kW with total capacity of 1 MW then 12 combustion units [2 + 10] were assumed).

Further details of the numbers of combustion units and combustion technologies are provided in Appendix 3 (Member State templates). The UK has a large number of the smallest combustion units reflecting energy provision in a number of education, medical and military establishments which tend to include a mix of medium-large boilers/CHP and a large number of decentralised or dispersed heating units typically less than 100 kW. These facilities frequently have a number of diesel-engine electricity generators for emergency or standby use with a very low load factor.

3.3.2 Fuel use in the selected Member States

Four Member States have provided information on numbers of combustion units in the different technology categories¹¹ (see appendix 3). The selected Member State combustion unit profile gives an idea on the number of combustion units in the categories determined by unit capacity, combustion technology and to fuel. Only the assumption on average capacity of a category and the assumed load factor is in addition necessary to determine the fuel use. Every size category was assigned an average capacity (0.5 MW_{th}, 10 MW_{th} and 25 MW_{th}) and this was multiplied by the number of units and the load hours to estimate fuel use. For Poland, the ETS authority was also able to provide a total fuel use and also data on fuel type.

¹¹ Romania was unable to provide this information at this stage of ETS implementation

Table 3-5 – Fuel use in selected Member States

Member State	Carbon emission, T _e CO ₂ eq EEA (2006)	Fuel use in 20-50 MW _{th} installations, TJ	Fuel use, TJ				
			Gas	Coal	Oil	Biomass	Other
Belgium	1395656	32313	25741	6156	405	5	5
Poland	4981058	61461	9338	2929	2492	45773 ¹²	0
Romania	-	15460	12490	2160	810	0	0
Slovenia	324769	11775	10196	585	286	702	5
United Kingdom	2426374	145725	138131	4927	270	1415	981

For the remaining Member States, the numbers of combustion units in the different technology categories is partially determined by the average MS profile Table 2-5. The unit capacity distribution and for most MS also the combustion technology distribution for the other MS are averages of selected MS. For fuel use though, GAINS fuel uses (IIASA 2007) in industrial boilers¹³ (combustion) is used for each MS to derive a distribution of the 4 fuel categories. In a category determined by capacity and technology, the installations are then split over the fuels on the derived MS specific fuel use.

3.3.3 Numbers of 20-50MW_{th} installation falling under IPPC and other National legislation

A summary of combustion installations in the selected MS which are directly associated with IPPC activities is provided in Table 3-6. This information is not used to make an extrapolation for EU-27. The EU ETS installations which are part of an IPPC installation were identified where possible from data supplied by the Member States. In some instances the IPPC activity could not be identified (an IPPC permit was recorded but the IPPC Directive Annex 1 activity was not stated) and the IPPC activity was assigned from knowledge of the operator's business activity.

The split of combustion installations into IPPC/non-IPPC categories is of importance because it is interesting to see how much installations would enter the IPPC system and because administration and regulation costs are an important factor in the analysis. But, the extension of the threshold to 20 MW_{th} affects all combustion units: IPPC and non-IPPC installations. While some installations in the 20-50 MW_{th} range are directly associated activities and already in theory covered by the IPPC Directive, extending the threshold of the IPPC Directive may however also lead to further emission reduction from these plant. The large combustion plant BREF does not contain BAT information for combustion installations <50 MW_{th}. Where there are directly associated 20-50 MW_{th} installations, the Member States' regulators apply a range of emission controls. Apart from an overestimated administration / regulation cost, the conclusions from this report are valid apart from the split IPPC/non-IPPC since the baseline scenario is the best approximation of current emissions.

Table 3-6 – 20-50 MW_{th} installations regulated under IPPC Directive

Member State	Direct assoc. to IPPC activities Note 1	Other national regulation Note 1	IPPC activity (annex 1 categories)					
			1	2	3	4	5	6
			Energy	Metals	Mineral	Chemicals	Waste	Other
Belgium	53 (63%)	31 (37%)	-	2	5	14	-	32
Poland	-	-	-	-	-	-	-	-
Romania	17 (37%)	-	1	4	4	2	-	6
Slovenia	13 (41%)	19 (59%)	-	1	1	4	-	7
United Kingdom	56 (14%)	19 (5%)	11	5	-	23	-	17

Note : 1. Figures in parentheses represent percentage of 20-50 MW_{th} installations.

¹² Although no detailed information, mainly wood.

¹³ Data from scenario "NEC_NAT_CLE3" (NEC03): national baseline scenario as of March 2007; for lack of data on SCI, fuel use from industrial boilers is used.

3.3.4 Load factors

The EEA report (EEA, 2007) indicated that load factors for smaller installations were often comparatively low (see Table 3-2), reflecting equipment redundancy and (for heating plant) limited use outside a heating season. Of course, this will depend on the main use for such plants e.g. whether heating, energy supply in industry (seasonal industry vs continuous). Analysis of data for individual installations in the UK and Belgium indicated an average load factor equivalent to 1400 and 1500 hours respectively of operation at rated capacity.

Note that the analysis has been undertaken on the basis of a range of two load factors equivalent to operation for 1000 and 3000 hours per year respectively (this range covers the indicated range of average load factors for all countries except Greece, the Netherlands, Portugal, Spain and Slovakia).

3.4 Overview of technologies

3.4.1 Combustion technologies

A wide range of combustion technologies are available, the main ones being the combustion of fuels in boilers or furnaces to provide heat. Boilers and furnaces burn a range of fuels from refined natural gas to solid biomass fuels.

Other relevant technologies considered in this study are gas turbines and engines which burn gaseous and liquid fuels. Gas turbines and engines provide electrical generation (or fluid compression and transfer) and are often used to provide co-generation. Many engines provide standby or emergency capacity and may be used very infrequently (for example standby or emergency generators and fire water pumps).

3.4.2 Emission abatement

Table 3-4 indicates that most combustion units in 20-50 MW_{th} installations are smaller than 3 MW_{th} and comparatively few are larger than 15 MW_{th}. This limits abatement options for existing installations because typical end-of-pipe abatement equipment is relatively more expensive for small combustion plant. Costs for abatement will also depend on the configuration of the installation (several units on one stack or separate stacks. In many cases fuel choice and combustion control will be relevant. In some cases, replacement by new (less-emitting) combustion units may be a more attractive option, particularly if energy efficiency gains can also be made.

Use of end-of-pipe NO_x abatement on small combustion units is developed for engines but is not common on other combustion technologies. End of pipe abatement is relevant for particulate emission from solid-fuel combustion with multi-cyclone and even fabric filter units applied to solid fuel boilers <1 MW_{th} in some Member States.

The use of combustion controls (for example low and ultra-low NO_x burners) can achieve substantial reduction in NO_x emissions from gas combustion but such controls can be difficult to retrofit in existing combustion units. Low NO_x burners for liquid fuels are not generally available for small combustion units. Low NO_x technology for solid fuel combustion in small combustion plant is essentially through use of flue gas recirculation or overfire air but scope for emission reduction on existing units may be limited. Fluid bed combustion units tend to have lower NO_x emissions than traditional grate units for solid fuel. Fluid bed combustors can also incorporate sorbent to reduce SO₂ emission.

Fuel switching (for example to natural gas) or control of fuel quality can provide significant emission benefits (for example limiting the sulphur content of fuel oils as in Directive 1999/32/EC on Sulphur Content of Certain Liquid Fuels).

The ECM (environmental costing model) database of abatement measures with their associated emission reduction potential and annual costs are translated into an emission reduction cost (€/tonne).

Table 3-7 and Table 3-8 provide the possible reductions and the cost data for a 3 MW_{th} and 10 MW_{th} unit with 1000 and 3000 load hours¹⁴, respectively. Figures 3-1 to 3-3 below provide a summary of the reduction costs for average combustion units in the range 3-25 MW_{th}.

In the NO_x example, the “stringent” reduction is attained by applying SCR end-of-pipe reduction technique. The “limited” reduction is attained by using the air staging technique. The figures illustrate that costs are dependent on the load hours assumed. This is because a reduction technique has a fixed investment cost no matter the load hours. To turn the investment costs into an annual cost, a linear depreciation period of 15 years is used without discounting.

Figures 3-1 to 3-3 are valid for a range of combustion units, although the following points are important:

- Capacity is also a factor determining the costs, but the effect of load hours is bigger because the scenarios assume low load levels. For installations smaller than 3 MW_{th} (on average 0,5 MW_{th}), abatement equipment can be relatively more expensive (and not linearly decreasing as assumed here). Although most combustion units in 20-50 MW_{th} are smaller than 3 MW_{th}, less than 10% of the emissions is from this category. The overall conclusion on the cost-benefit is not greatly influenced by those small combustion units because the average cost for reducing emissions does not increase significantly. However, it is worth noting that the marginal net-benefit per tonne emission reduction for a combustion unit < 3 MW_{th} (marginal benefit minus marginal cost) is much lower because the marginal costs per tonne emission reduction are higher and thus much closer to benefits of an avoided tonne.
- The abatement measures are for boilers/steam turbines. It is assumed that for engines, the reduction cost is in the same range.
- Although the potential reduction differs from fuel to fuel, the reduction cost is mainly determined by load hours and required reduction. Some techniques are ignored in determining the reduction cost because they are too expensive, e.g. exhaust gas recirculation on existing oil boilers.

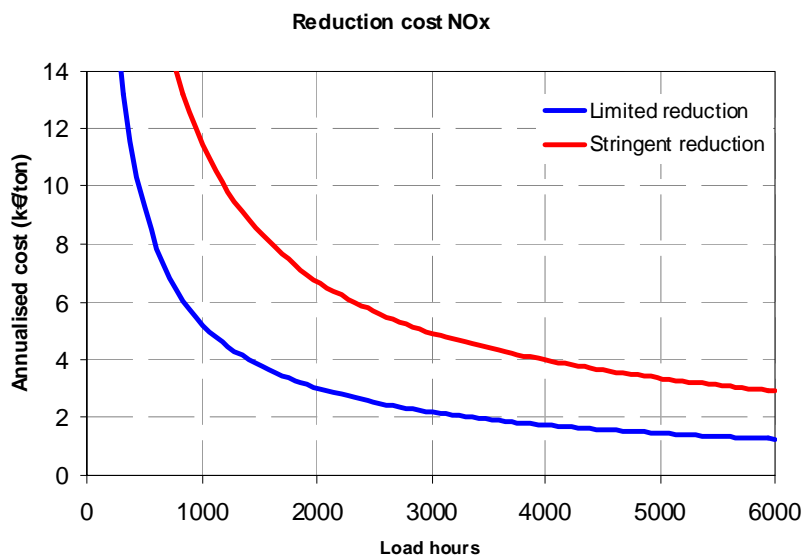


Figure 3-1 Illustration of NO_x reduction costs

¹⁴ For combustion units with very small load hours, costs are underestimated. If load hours are 300 instead of 1000, annual costs per avoided ton of emission are underestimated with 200%. Average load hours are however a good estimate.

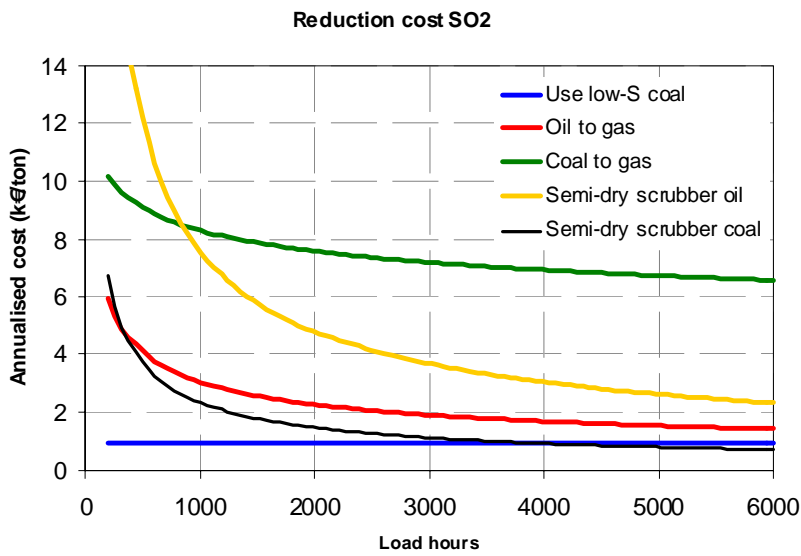


Figure 3-2 Illustration of SO₂ reduction costs

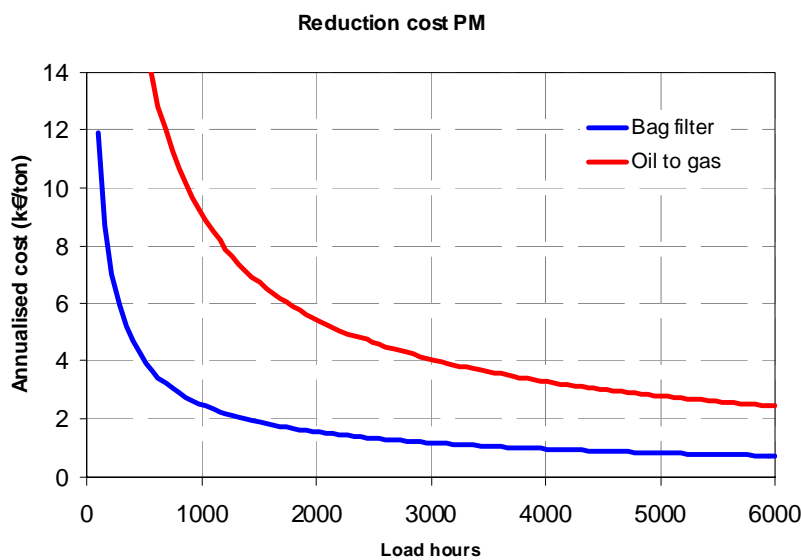


Figure 3-3 Illustration of PM reduction costs

Table 3-7 Emission reductions for different abatement measures

Pollutant and abatement measure	Emission Reduction - coal	Emission Reduction - oil	Emission Reduction - gas
	%	%	%
NOx Techniques			
Low NOx burner	/	30%	40%
Air Staging	/	30%	30%
Exhaust Gas Recirculation	30%	10%	30%
Low Nox + EGR	/	35%	58%
Small SCR	85%	85%	85%
SO₂ Techniques			
Use low S-coal	50%	/	/
Switch HFO/LFO mix to LFO	/	75%	/
Switch HFO/LFO mix to natural gas	/	100%	/
Switch from coal to gas	100%	/	/
DeSox Semi dry	85%	85%	/
DeSox Wet	95%	95%	/
PM Techniques			
Bag filter	99%	99%	/
Switch HFO/LFO mix to natural gas	/	99%	/
Switch from coal to gas	99%	/	/

Table 3-8 Example of costs for a 3 MW_{th} combustion unit operating for 1000 hours and for a 10 MW_{th} combustion unit operating for 3000 hours

Pollutant and abatement measure	3 MW _{th} , 1000 hours		10 MW _{th} , 3000 hours	
	Annualised investment cost	Annualised variable cost	Annualised investment cost	Annualised variable cost
	(€/y)	(€/y)	(€/y)	(€/y)
NOx Techniques				
Low NOx burner	2667	0	8267	0
Air Staging	1467	300	4267	3000
Exhaust Gas Recirculation	1207	450	3400	4500
Low Nox + EGR	3607	450	11400	4500
Small SCR	6913	4131	23042	41310
SO₂ Techniques				
Use low S-coal	0	3240	0	32400
Switch HFO/LFO mix to LFO	0	16200	0	162000
Switch HFO/LFO mix to natural gas	2667	3240	8267	32400
Switch from coal to gas	6933	48600	20000	486000
DeSox Semi dry	18036	3600	29195	36000
DeSox Wet	42998	3600	61703	36000
PM Techniques				
Bag filter	3000	1500	10000	15000
Switch HFO/LFO mix to natural gas	2480	900	8267	9000
Switch from coal to gas	6000	48600	20000	486000

3.5 Pollutant emissions

This section summarises the data collection for estimating the emissions in the MS for the baseline scenario and the scenario with stringent national ELV's. General emission factors are used for the baseline scenario. Where emission limit values for existing plants in a Member State are known and the associated emission factor is lower than the general emission factor, the lower emission factor has been applied. For the scenario with stringent national ELV's, data on the ELV's for new plants in MS was collected.

3.5.1 Default emission factors

Although emissions data are collected for small combustion installations in some Member States, most Member States' pollutant emission estimates are developed from aggregate emission factors and national fuel use in manufacturing and other relevant activities. These aggregated activity data include combustion in installations or sectors which are not relevant to this study (for example residential and industrial installations smaller than 20 MW_{th}).

Emission estimates have been developed for the Member States (and EU) from published default emission factors (modified by emission limit values where appropriate) and for an estimated fuel use developed for the relevant installations from reported CO₂ emissions and aggregated fuel use.

For this analysis, combustion technologies have been grouped:

- Boilers and furnaces
- Gas turbines
- Engines

The basic emission factors for the combustion units have been derived from default emission factors published in the UNECE Corinair Task Force for Emission Inventories and Projections (TFEIP) emission inventory guidebook (EEA, 2006b) and United States Environmental Protection Agency (USEPA) emission factor handbook. These factors are intended to be representative of the range of combustion technologies in use in Europe and North America. The emission factors for the general case (the baseline scenario) but not including modifications for Member States are summarised in Table 3-9.

Table 3-9 - Summary of emission factors applied for general case (baseline scenario)

Pollutant and combustion unit technology	Emission factors g/GJ heat input							
	Combustion units >15 MW _{th} , 3-15 MW _{th}				Combustion units <3 MW _{th}			
	Gas	Liquid	Wood	Coal	Gas	Liquid	Wood	Coal
NO_x (as NO₂)								
Boiler	70	100	150	180	70	100	150	160
Furnace	70	100	150	180	70	100	150	160
Gas turbine	138	379			138	379		
Engine	1357	1314			1357	1314		
PM₁₀								
Boiler	0	40	67	76	0	3	240	190
Furnace	0	40	67	76	0	3	240	190
Gas turbine	2.8	5.2			2.8	5.2		
Engine	6.9	79			6.9	79		

Note that the range of emission characteristics within the chosen technologies can be quite wide (for example engines include compression ignition and spark ignition units which have a wide range of NO_x emission factors).

For SO₂, the ELV for unabated combustion units is determined by fuel sulphur content. Limits on the sulphur content of fuels are therefore specified for the baseline scenario instead of ELV (see par. 4.6).

3.5.2 Emission limit values

Where emission limit values in a Member State are known and the associated emission factor is lower than the general emission factor, the lower emission factor has been applied. Emission limit values of existing plant were taken. When plants are distinguished in the legislation on the basis of the year of construction ("new" since 1993), sometimes a value is taken from an average year of construction. For the scenario with stringent national ELV's, data on the ELV's for new plants in MS was collected.

Emission limit values (ELVs) were obtained from Member States, the Commission's report (AEAT, 2004) on small combustion installations and from the websites of regulatory authorities:

- Belgium
- Czech Republic
- Finland
- France
- Germany
- Italy
- Romania
- Slovakia
- Slovenia
- United Kingdom

Note that the ELVs which are applied for installations < 50 MW_{th} by Member States are generally dependant of the type and size of combustion unit, rather than installation capacity.

Emission limit values are applied for various pollutants by the Member States for installations and combustion units smaller than 50 MW_{th}. Further details of the individual Member States' ELVs are provided in Appendix 4. A summary of the range of national ELVs applied to new combustion plant for different fuels is provided in Table 3-10. Note that ELVs for some Member States have been recalculated where necessary to the stated reference oxygen concentration.

Table 3-10 – Range of air pollutant emission limit values applied to new plant

Technology & Unit size	Fuel ¹⁵	Reference Oxygen % v/v dry	ELVs mg/m ³ , dry, 0°C, 101.3 kPa, at reference O ₂		
			NO _x (as NO ₂)	SO ₂	PM
Boilers	Coal	6	100-1500	200-2700	21-1000
	Wood	6	250-1500	200-2700	30-1000
	Oil	3	200-1500	350-2700	20-100
Gas turbines	Natural Gas	3	120-1500	35-2700	5-50
	Oil	15	115-150	-	-
Engines	Natural Gas	15	60-115	-	-
	Oil	15	186-750	-	7
	Natural Gas	15	186-750	600	7-60

In general, Member States specify ELVs for NO_x, particulate matter and SO₂ (but generally only for specified fuels). There is a wide range in limits applied across the Member States. Limits on the sulphur content of fuels are often specified instead of an ELV for SO₂. Other pollutants with ELVs include carbon monoxide (CO) and volatile organic compounds (VOC). Some Member States have limit values on additional pollutants, for example formaldehyde (from engines in Germany) and selected trace elements (France).

Emission limit values are typically expressed as a mass concentration (usually for a dry gas at 273K/0°C, 101.3 kPa and at a specified reference oxygen content). The concentration can be developed into an emission factor from knowledge of the stoichiometric flue gas volume per unit of energy input (for example from fuel analysis or from published data such as USEPA Method 19) and

¹⁵ Fuels have been aggregated into four main types based on GAINS classifications, coal includes lignite and coke for some countries. Similarly wood is an aggregation of solid biomass and oil covers heavy fuel oil and gas oil.

an excess air correction factor. Those converted ELVs are used to modify the general case factors in Table 3-9.

4 EMISSION CONTROL SCENARIOS

In total, six scenarios were developed. Apart from the baseline scenario, there are 2 LCPD scenarios, a BREF scenario, a stringent national ELV scenario and a Maximum Feasible Reduction scenario. The basic assumption in each scenario is a set of ELVs for NO_x and PM₁₀ and an assumed fuel sulphur content for each fuel. The assumptions are summarised in paragraph 4.1 to 4.6. The assumptions for SO₂ are dealt with separately in paragraph 4.7.

The large combustion plant BREF does not contain BAT conclusions for combustion installations <50 MW_{th}, thus also other documents are used apart from the large combustion BREF. The ELVs for the different scenarios are chosen so that it covers a range of possible options to reduce emissions, building upon existing ELVs from different sources.

The ELVs were converted to emission factors using published stoichiometric dry flue gas volumes (from US EPA Method 19) adjusted to the appropriate reference oxygen content.

4.1 Business as usual (Baseline)

The Business as Usual (or reference) scenario has been built with the current emissions and assumes the implementation of all present national emission legislations. The data from the Member States forms the basis of this reference scenario:

- Number of installations
- Combustion unit profile
- Type of combustion technology and load factor
- Type and quantity of fuels
- National legislation and applied ELVs
- Current emissions (and abatement measures)

The details of the basis of the reference scenario are provided at Appendix 5. Analysis was undertaken at two load factors (equivalent to 1000 and 3000 hours annual operation) to assess the sensitivity of the analysis to installation fuel use. Some parameters of this scenario are part of the uncertainty analysis.

4.2 LCPD Scenario (existing plant)

This scenario applies the ELVs specified for existing 50 MW_{th} plants in the LCP Directive to 20-50 MW_{th} installations. For some MS, the emission factors derived from LCPD ELVs for existing plants tend to be higher than the default emission factors from the baseline scenario. For the MS with lower ELVs, we assumed no change in ELVs. It turned out that, on average, the NO_x and SO_x emissions of this scenario were close to the baseline scenario. That is why only the effect of lower PM₁₀ is taken into account.

Table 4-1 – Summary of ELV concentrations for LCPD scenario (existing)

Fuel	Ref O ₂	Gas	Liquid	Wood (biomass)	Coal
	% v/v dry	NO_x Emission limit value, mg/m³ at 0°C, 101.3 kPa			
Boilers	3 (gas & liquid) 6 (solid fuel)	300	450	600	600
Gas turbines	15	300	300	-	-
		PM₁₀ Emission limit value, mg/m³ at 0°C, 101.3 kPa			
Boilers	3 (gas & liquid) 6 (solid fuel)	5	50	100	100

Note : ELVs have been standardised to stated oxygen values, original ELVs may have been at a different oxygen content.

Table 4-2 – Summary of emission factors for the LCPD scenario (existing)

Fuel	Gas	Liquid	Wood (biomass)	Coal
	NO _x Emission factors ¹⁶ , g/GJ (heat input basis)			
Boilers	85	127	231	217
Gas turbines	258	258	-	-
	PM ₁₀ Emission factors ¹⁷ , g/GJ (heat input basis)			
Boilers	1.4	14.1	38.6	36.2

4.3 LCPD Scenario (new plant)

This scenario applies the ELVs specified for new 50 MW_{th} plants in the LCP Directive to 20-50 MW_{th} installations. The emission factors used in this scenario are provided in Table 4-4.

Table 4-3 – Summary of ELV concentrations for LCPD scenario (new)

Fuel	Ref O ₂	Gas	Liquid	Wood (biomass)	Coal
	% v/v dry	NO _x Emission limit value, mg/m ³ at 0°C, 101.3 kPa			
Boilers	3 (gas & liquid) 6 (solid fuel)	150	400	400	400
Gas turbines	15	50	120	-	-
		PM ₁₀ Emission limit value, mg/m ³ at 0°C, 101.3 kPa			
Boilers	3 (gas & liquid) 6 (solid fuel)	5	50	50	50

Note : ELVs have been standardised to stated oxygen values, original ELVs may have been at a different oxygen content.

Table 4-4 – Summary of emission factors for the LCPD scenario

Fuel	Gas	Liquid	Wood (biomass)	Coal
	NO _x Emission factors ¹⁸ , g/GJ (heat input basis)			
Boilers	42.5	113	154	145
Gas turbines	43.0	103	-	-
	PM ₁₀ Emission factors ¹⁹ , g/GJ (heat input basis)			
Boilers	1.4	14.1	19.3	18.1

4.4 LCP BREF Scenario

The scenario assumes that BAT and the associated emission levels (AELs) for 20-50 MW_{th} plants would be the same as those for new 50 MW_{th} plants in the LCP BREF. The BREF generally provides AELs as a range and the factors chosen for this scenario represent the upper end of the BAT range for new plant (this provides a progression of emission controls through the scenarios).

¹⁶ Emission factors derived from emission limit concentrations in revised Large Combustion Plant Directive 2001/80/EC using fuel exhaust gas volume factors in USEPA Method 19.

¹⁷ Assumes all particulate is emitted as PM₁₀.

¹⁸ Emission factors derived from emission limit concentrations in revised Large Combustion Plant Directive 2001/80/EC using fuel exhaust gas volume factors in USEPA Method 19.

¹⁹ Assumes all particulate is emitted as PM₁₀.

Table 4-5 – Summary of ELV concentrations for LCP BREF scenario

Fuel	Ref O ₂	Gas	Liquid	Wood (biomass)	Coal
	% v/v dry	NO _x Emission limit value, mg/m ³ at 0°C, 101.3 kPa			
Boilers	3 (gas & liquid) 6 (solid fuel)	100	450	250	450
Gas turbines	15	50	90	-	-
		PM ₁₀ Emission limit value, mg/m ³ at 0°C, 101.3 kPa			
Boilers	3 (gas & liquid) 6 (solid fuel)	-	20	20	20

Note : ELVs have been standardised to stated oxygen values, original ELVs may have been at a different oxygen content.

Table 4-6 - Summary of emission factors for the BREF scenario

Fuel	Gas	Liquid	Wood	Coal
	NO _x Emission factors ²⁰ , g/GJ (heat input basis)			
Boilers	28.3	127	96.4	163
Gas turbines	43.0	77.3	-	-
	PM ₁₀ Emission factors, g/GJ (heat input basis)			
Boilers	-	5.7	7.7	7.2

4.5 Stringent National Emission Limit Value Scenario

The scenario assumes that ELVs would be similar to the most strict national ELVs of the Member States (generally applicable to new plants) (Table 4-7). Note that the most stringent limit has been adopted for each fuel, size and technology category (that is the limits are from several Member States). For the purposes of developing the scenario the BREF AELs have also been considered. The applied emission factors are summarised in Table 4-8. This scenario can be considered to represent emissions which would be consistent with application of Best Available Techniques (BAT) although the technologies used are not defined by this study.

Table 4-7 – Summary of ELV concentrations for most stringent ELV scenario

Fuel	Ref O ₂	Gas	Liquid	Wood	Coal
	% v/v dry	NO _x Emission limit value, mg/m ³ at 0°C, 101.3 kPa			
Boilers	3 (gas & liquid) 6 (solid fuel)	50	150	150	90
Gas turbines	15	60	115	-	-
Engines	15	165	330	-	-
		PM ₁₀ Emission limit value, mg/m ³ at 0°C, 101.3 kPa			
Boilers	3 (gas & liquid) 6 (solid fuel)	0	5	5	5

Note : ELVs have been standardised to stated oxygen values, original ELVs may have been at a different oxygen content.

Table 4-8 – Summary of emission factors for most stringent ELV scenario

Fuel	Gas	Liquid	Wood	Coal
	NO _x Emission factors ²¹ , g/GJ (heat input basis)			
Boilers	14.2	42.4	57.9	32.6
Gas turbines	51.5	98.7	-	-
Engines	141.6	283.0	-	-
	PM ₁₀ Emission factors, g/GJ (heat input basis)			
Boilers	0.0	1.4	1.9	1.8

²⁰ Emission factors derived from upper range of AEL concentrations for new plant in Large Combustion Plant BREF document using fuel exhaust gas volume factors in USEPA Method 19.

²¹ Emission factors derived from most strict national emission limit concentrations using fuel exhaust gas volume factors in USEPA Method 19.

4.6 Maximum Feasible Reduction

The maximum feasible reduction (MFR) scenario generally reflects very expensive emission reduction costs. MFR assumes almost full implementation of the currently available and most advanced technical emission control measures. This might include for example, ultra low NO_x gas burners or selective catalytic reduction (SCR). Such technology is not easily retrofitted to existing plant but is achievable on new plant and emissions are substantially lower than ELVs applied to small gas boilers by Member States and the BAT associated emission levels for large combustion plant in the BREF.

Table 4-9 – Summary of ELV concentrations for most stringent ELV scenario

Fuel	Ref O ₂ % v/v dry	Gas	Liquid	Wood	Coal
Combustion units <3 MW_{th}					
NO _x Emission limit value, mg/m ³ at 0°C, 101.3 kPa					
Boilers	3 (gas & liquid) 6 (solid fuel)	50	150	150	90
Gas turbines	15	60	115	-	-
Engines	15	165	330	-	-
PM ₁₀ Emission limit value, mg/m ³ at 0°C, 101.3 kPa					
Boilers	3 (gas & liquid) 6 (solid fuel)	0	5	5	5
Combustion units 3-15, 15-50 MW_{th}					
NO _x Emission limit value, mg/m ³ at 0°C, 101.3 kPa					
Boilers	3 (gas & liquid) 6 (solid fuel)	37.1	53.0	58.3	74.5
Gas turbines	15	24.0	66.2	-	-
Engines	15	236.9	229.5	-	-
PM ₁₀ Emission limit value, mg/m ³ at 0°C, 101.3 kPa					
Boilers	3 (gas & liquid) 6 (solid fuel)	0	5	5	5

Note : ELVs have been standardised to stated oxygen values, original ELVs may have been at a different oxygen content.

Table 4-10 – Summary of emission factors for maximum feasible reduction scenario

Fuel	Gas	Liquid	Wood	Coal
Combustion units <3 MW_{th}				
NO _x Emission factors ²² , g/GJ (heat input basis)				
Boilers	14.2	42.4	57.9	32.6
Gas turbines	51.5	98.7 ²³	-	-
Engines	141.6	283	-	-
PM ₁₀ Emission factors, g/GJ (heat input basis)				
Boilers	0.0	1.4	1.9	1.8
Combustion units 3-15, 15-50 MW_{th}				
NO _x Emission factors, g/GJ (heat input basis)				
Boilers	10.5	15.0	22.5	27.0
Gas turbines	20.7	56.9	-	-
Engines	204	197	-	-
PM ₁₀ Emission factors, g/GJ (heat input basis)				
Boilers	0.0	1.4	1.9	1.8

4.7 SO₂ assumptions for all scenarios

Assumptions for SO₂ are shown in the tables below.

²² Emission factors derived from most strict national emission limit concentrations and 85% reduction from general case using fuel exhaust gas volume factors in USEPA Method 19.

²³ Note that LCP BREF is more stringent; average capacity is however much smaller. It is considered unlikely to be considered BAT for such small units.

Table 4-11 – Summary of SO₂ assumptions for all reduction scenario

	Coal	Oil	Biomass
Baseline	1%	Equal mix of 1% and 0.1% oil	0.03%-0.12%
LCPD (existing)	2000 mg/Nm3	Equal mix of >1% (1700 mg/Nm3) oil and 0.1% oil	0.03%-0.09%
LCPD (new)	850 mg/Nm3	Equal mix of >0.5% (850 mg/Nm3) oil and 0.1% oil	0.03%-0.09%
BREF	400 mg/Nm3	Equal mix of >0.2% (350 mg/Nm3) oil and 0.1% oil	50 mg/Nm3
MS	400 mg/Nm3	Equal mix of 1% and 0.1% oil	0.03%-0.12%
MFR	90 mg/Nm3	As if all oil is 10 ppm oil (0.001%)	50 mg/Nm3

Table 4-12 – Summary of SO₂ emission factors for all reduction scenario

	Coal	Oil	Biomass
Baseline	666	200	25-100
LCPD (existing)	725	266	25-75
LCPD (new)	308	145	25-75
BREF	145	75	19
MS	145	200	25-100
MFR	33	0	19

5 ANALYSIS

5.1 Summary of emissions under the various scenarios

The EU27 emissions of NO_x, SO₂ and PM are summarised in Table 5-1. The scenarios examined correspond to progressively more stringent emission controls for NO_x and PM, that is LCPD<LCP BREF<Most stringent Member State<MFR. The SO₂ control strategies applied are also progressively more rigorous except for the most stringent Member State controls which are less rigorous than the LCP /BREF which applies to larger installations.

Table 5-1 Summary of emissions under the reference and control scenarios

Annual operating hours and pollutant	Emissions, Tonnes/year					
	Baseline	LCPD (existing)	LCPD (new)	BREF	MS	MFR
1000 hrs						
NO _x	56415	56415	54187	49419	13570	9975
PM	9792	5020	3216	1358	620	620
SO ₂	50229	50229	26709	12379	21305	2610
3000 hrs						
NO _x	119360	119360	102739	87267	31457	20301
PM	20461	10799	7127	2675	1004	1004
SO ₂	86479	86479	50211	22944	48317	4714

Table 5-2 Summary of emission reductions under the reference and control scenarios

Annual operating hours and Pollutant	Emission reductions, in % of baseline emissions and Tonnes/year					
	Baseline	LCPD (existing)	LCPD (new)	BREF	MS	MFR
1000 hrs						
NO _x		0%	4%	12%	76%	82%
PM		49%	67%	86%	94%	94%
SO ₂		0%	47%	75%	58%	95%
3000 hrs						
NO _x		0%	14%	27%	74%	83%
PM		47%	65%	87%	95%	95%
SO ₂		0%	42%	73%	44%	95%
1000 hrs						
NO _x		0	2228	6996	42846	46441
PM		4772	6576	8434	9173	9173
SO ₂		0	23521	37850	28924	47619
3000 hrs						
NO _x		0	16621	32093	87903	99059
PM		9662	13334	17786	19457	19457
SO ₂		0	36268	63535	38162	81765

The range of NO_x emissions arising from the baseline and emission control scenarios under both load factors (left: 1000 hours and right: 3000 hours) are compared in Figure 5-1.

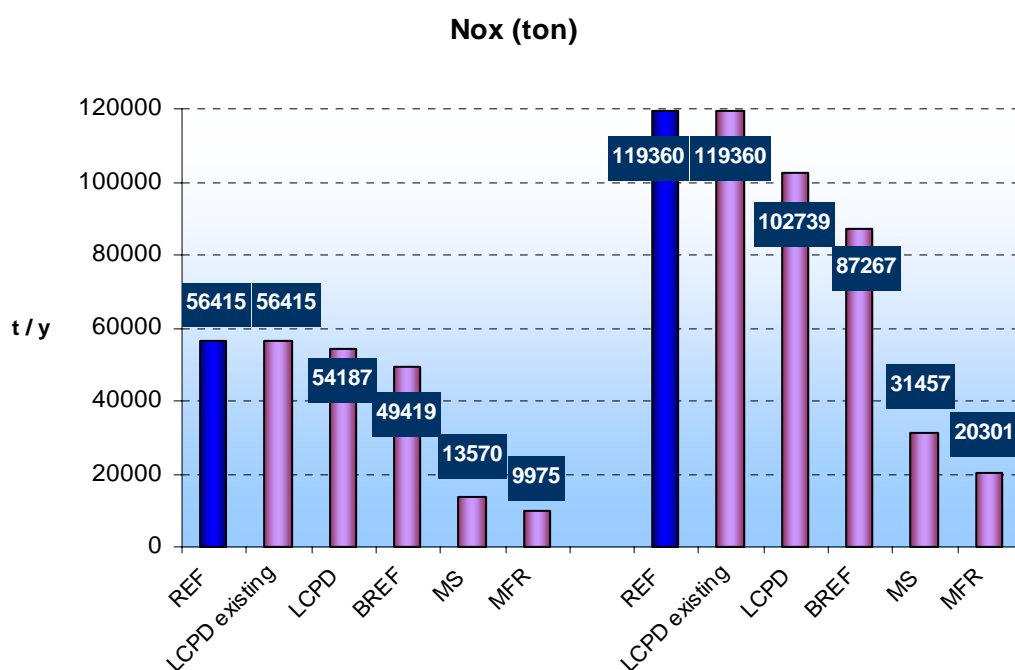


Figure 5-1 NOx emissions for reference (REF) and emission control scenarios under both load factors

The baseline emission estimates of NO_x, SO₂ and PM are lower than the total industrial combustion (< 50 MW) emissions estimated earlier under CAFE (AEA 2004), see Table 5-3. This reflects a number of differences between the two exercises including:

1. The CAFE estimates include all industrial combustion <50 MW_{th}
2. Differences in activity data – the current estimates include fuel use data based on actual fuel use in 20-50 MW_{th} installations (not available for previous study) whereas the CAFE estimates are scaled from national emission submissions.
3. Differences in emission factors – the current study uses recent revision to emission factors.

Table 5-3 Comparison with CAFE industrial combustion emission estimates

Pollutant	CAFE industrial combustion emission, tonnes (< 50 MW)	3000 hour baseline emission estimate, tonnes (20-50 MW) (% of CAFE)
NO _x	487 000	119 360 (25 %)
SO ₂	844 000	86 479 (10 %)
PM	137 000	20 461 (15 %)

Table 5-4 provides a comparison of the baseline NO_x, SO₂ and PM emissions with the total emissions for EU-25 for 2004 (Eurostat). The total emissions are based on inventory data submitted by Member States under the UN Convention on Long Range Transboundary Air Pollution (CLRTAP).

Table 5-4 Comparison with total EU-25 emission estimates

Pollutant	Total 2004 EU-25 emission (Eurostat), tonnes	3000 hour baseline emission estimate, tonnes
NO _x	10 998 447	119 360
SO ₂	7 016 488	86 479
PM	2 252 846	20 461

5.2 Cost Benefit Analysis

5.2.1 Scenarios

The cost/benefit analysis covering the three pollutants NO_x, SO₂ and PM was undertaken for the various scenarios, applying the two load factors (1000 and 3000 hrs/year).

Table 5-5 – Summary of benefit analysis, M€(EU27)

Cost/benefit analysis	Value, M€					
	Baseline	LCPD (existing)	LCPD (new)	BREF	MS	MFR
1000hrs pa						
Annual operation cost ^[note 1]	2433	2612	2723	2976	3135	3495
Cost for emissions reduction ^[note 4]	-	179	290	543	702	1062
External cost ^[note 2]	1494	1286	979	685	387	168
Benefit of reduced emissions ^[note 3]	-	208	517	810	1108	1327
Net benefit	-	29	227	266	405	265
3000hrs pa						
Annual operation cost ^[note 1]	6695	6874	6986	7256	7420	7684
Cost for emissions reduction ^[note 2]	-	179	291	561	725	989
External cost ^[note 3]	2907	2545	1886	1227	860	317
Benefit of reduced emissions ^[note 4]	-	365	1023	1680	2051	2593
Net benefit	-	185	732	1118	1326	1604

Notes :

1. This is the annual cost for operating the combustion plants. In the reduction scenarios, the compliance costs and the administration costs for authorities and operators are included
2. Difference between scenario and reference annual operation cost. It includes the administration costs for authorities and operators. This cost is for every scenario about 160 M€.
3. External cost represent the monetized health and other negative impacts (on ecosystems, damage to buildings etc..)
4. Difference between scenario and reference external cost

The analysis indicates a net benefit even for the most stringent measures and for the low load factor, note that the ratio of net benefit between low and higher load factor are not simply the ratio of the load factor (operating hours) as some costs are independent of load factor.

5.2.2 Uncertainty and sensitivity analysis

The results of the uncertainty and sensitivity analysis of all scenarios are provided²⁴ in Appendix 6. Uncertainties were applied to the key inputs of the model and a Monte Carlo analysis was undertaken to assess the uncertainty of the costs, benefits and net benefit outcomes. Initial analysis indicated that the most significant parameter would be the operating hours and this was so significant that it masked the uncertainty arising from the other parameters. Consequently the operating hours parameter was removed from the uncertainty analysis and 'fixed' for the two load factors of 1000 and 3000 hours.

Major other uncertainties have been identified as:

- Emission factors (baseline scenario)
- The sulphur content of coal (all scenarios)
- The external costs of avoided emissions (all scenarios)
- The load hours for engines (all scenarios)

The emissions in the reference case are subjected to uncertainty. Therefore, a uniform distribution is imposed so that emission of NO_x and PM can vary between 70 and 130 % of the general case. For all

²⁴ Except for the LCPD existing scenario

scenarios, a 50% deviation on the sulphur content of coal is possible to the lower and higher ends. The sulphur content of liquids is assumed to be fixed. For the external costs, a uniform distribution is imposed. The range corresponds to the range of member specific values from the CAFE analysis using the low (median value of a life year - VOLY) and high (mean value of statistical life - VSL) values for 2010. For the load hours of engines, a 50% deviation is possible to the lower and higher ends.

The analysis for the 'MS' scenario (application of the most stringent Member State limits) is illustrated in Figures 5-2 to 5-4. (for 1000 hours/year operation). The band that is indicated with the small triangles on the X-axis is the 50% certainty band. The net benefit for the 'MS' scenario is i.e. with probability of 50% in the range of 200-600 M€2005.

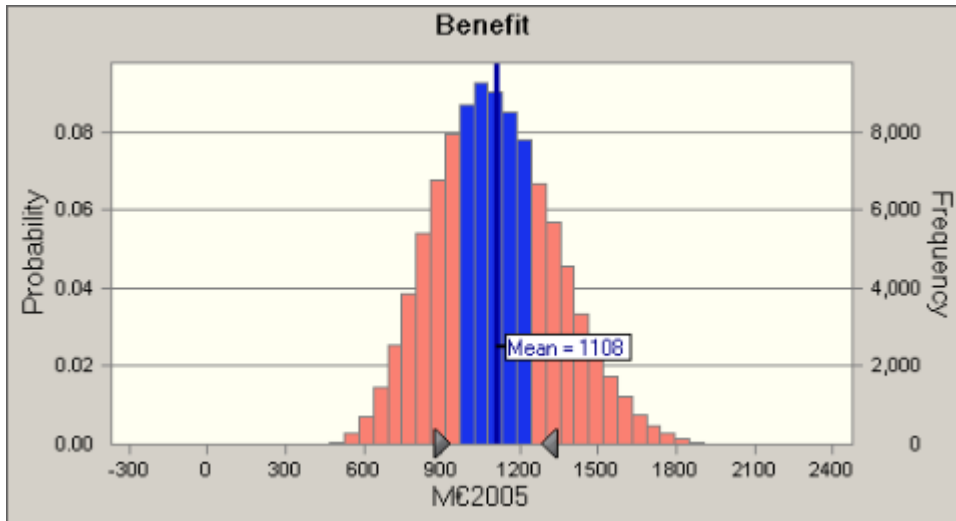


Figure 5-2 Benefit analysis for Most Stringent Member State scenario (1000 hours)

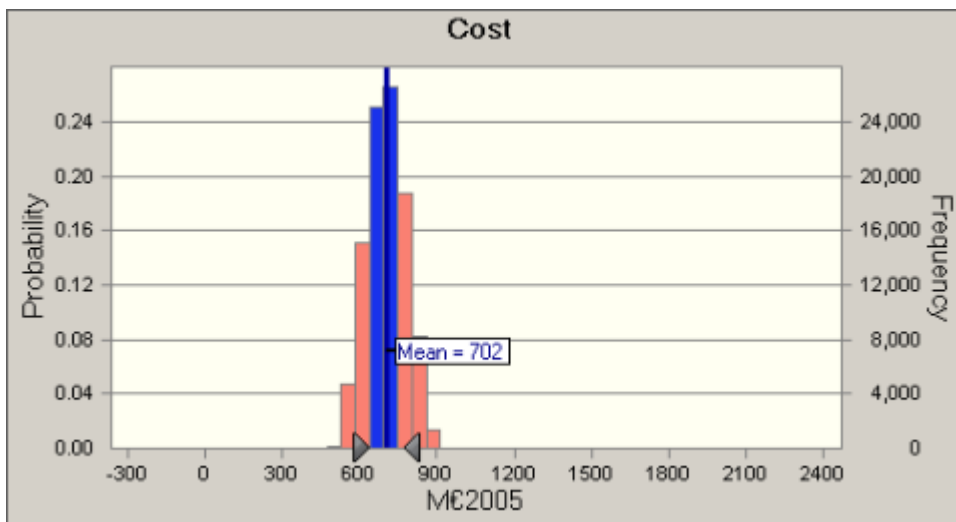


Figure 5-3 Cost analysis for Most Stringent Member State scenario (1000 hours)

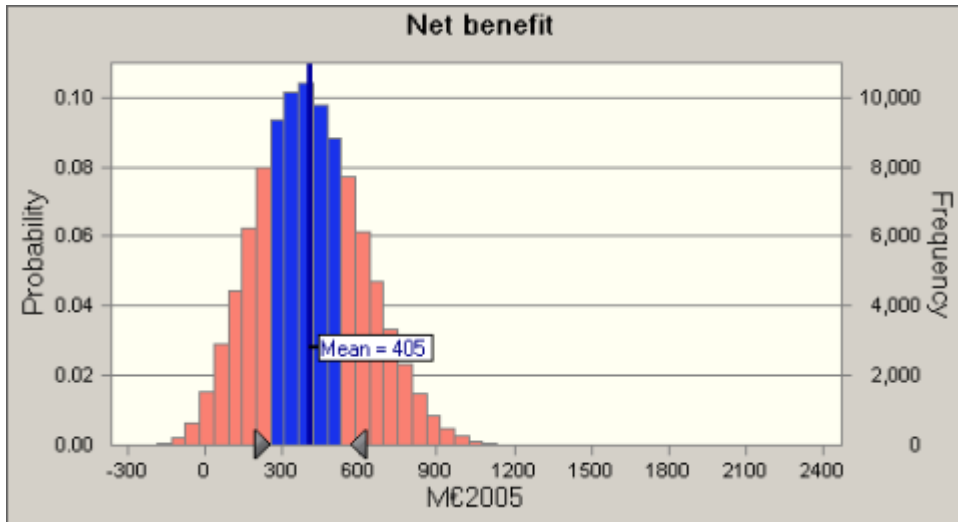


Figure 5-4 Net benefit analysis of Most Stringent Member State scenario (1000 hours)

Also a sensitivity analysis was undertaken to determine the most significant sources of uncertainty for the analysis of net benefits. The results for the ‘MS’ scenario are summarised in

Figure 5-5 and indicate that the external damage costs are the most significant source of uncertainty and, in this particular scenario, the uncertainty associated with PM damage. The uncertainties of the reference emissions have a lower impact on the overall uncertainty.

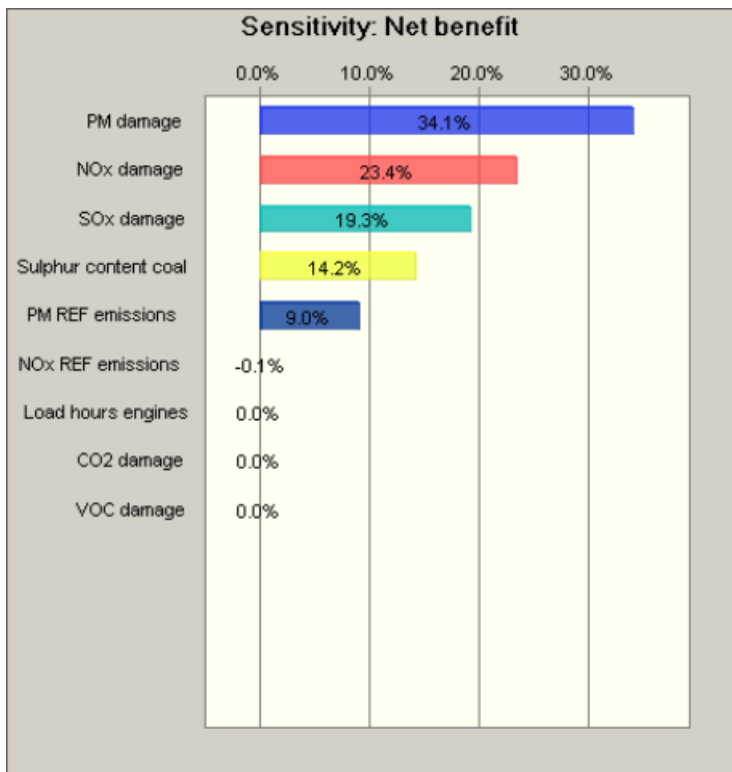


Figure 5-5 Sensitivity analysis for Most Stringent scenario (1000 hours)

From above analysis, we can conclude that the overall uncertainty is (after load hours) mainly determined by uncertainty in the benefits. The conclusion of a positive net benefit (benefits minus costs) in all scenarios is not undermined by overall uncertainty, because in all scenarios the 50%

certainty band is positive. For the MFR scenario with 1000 load hours, there is no net benefit in 25% of the cases (see appendix 6).

6 CONCLUSIONS

The cost benefit analysis indicates that despite low load factors, substantial numbers of smaller combustion units and lower emission estimates than previous studies, the potential emission reductions from inclusion of 20-50 MW_{th} combustion installations in IPPC - under a variety of emission reduction scenarios - would result in a net benefit. A 20-50 MW_{th} installation mostly consist of different combustion units whose capacity is usually significant smaller than the one of the whole installation. Although most combustion units in 20-50 MW_{th} are smaller than 3 MW_{th}, less than 10% of the emissions is from this category. The overall conclusion on the cost-benefit is not much influenced by those small combustion units because the average cost for reducing emissions does not go up much. However, the marginal net-benefit per tonne emission reduction for a combustion unit < 3 MW_{th} (marginal benefit minus marginal cost) is much lower because the marginal costs per tonne emission reduction are higher and thus much closer to benefits of an avoided tonne.

Sensitivity analysis indicates that after load factor, damage costs are the main sources of uncertainty. However, the conclusion of a positive net benefit (benefits minus costs) is not undermined by overall uncertainty, because in all scenarios the 50% certainty band is positive. For the MFR scenario with 1000 load hours, there is no net benefit in 25% of the cases.

The ETS data provided a reasonable basis for developing an inventory of the 20-50 MW_{th} installations, their technologies and emissions. No assumptions were made on whether or not a "de minimis rule" (excluding combustion units below a certain capacity, e.g. 3 MW) had been applied for the purpose of the ETS as this could not be fully assessed from the data available.

The existing arrangements for 20-50 MW_{th} installations under ETS make a very strong argument to harmonise the installation thresholds in ETS and IPPC. Extending the IPPC energy installation threshold to a different threshold would make administration more costly and result in lower net benefits. The relevant installations are already known because of inclusion in ETS, the ETS installation definitions are consistent with IPPC and some installations are already directly-associated with IPPC activities.

The cost benefit analysis in this report have made a distinction between technologies used and between capacities (0-3 MW_{th}, 3-15 MW_{th} and > 15 MW_{th}). This report provides an overall view on costs and benefits and does not conclude on the different Best Available Techniques for the combustion installations smaller than 50 MW_{th}. To allow consistent application of BAT, the Best Available Techniques Reference would need to be extended to include 20-50 MW_{th} installations.

7 REFERENCES

AEA 2004, Costs and environmental effectiveness of options for reducing air pollution from small-scale combustion installations, report reference AEAT/ED48256/Final report Issue 2 produced by AEA Technology for Clean Air For Europe programme (EC DG Environment).

AEA 2005, Damages per tonne emission of PM_{2.5}, NH₃, SO₂, NO_x and VOCs from each EU25 Member State (excluding Cyprus) and surrounding seas, report reference AEAT/ED51014/CAFE CBA produced by AEA Technology for Clean Air For Europe programme (EC DG Environment).

Defra 2007, Mid term review of the UK's implementation of the pollution prevention and control regulations, report by Atkins for UK Dept for Environment, Food and Rural Affairs (Defra), April 2007.

EEA 2006a, Application of the emissions trading directive by EU Member States, technical Report 2/2006 produced by the European Environment Agency

EEA 2006b. Corinair Emission Factor Handbook produced by the European Environment Agency for the UNECE Task Force on Emission Inventories and Projections.

EEA 2007, Application of the emissions trading directive by EU Member States, technical Report 4/2007 produced by the European Environment Agency

European Commission:

Reference Document on Best Available Techniques for Large Combustion Plants July 2006 produced by the European IPPC Bureau.

Directive 96/61/EC concerning integrated pollution prevention and control.

Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC.

Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants. Directive 1999/32/EC relating to a reduction in the sulphur content of certain liquid fuels and amending Directive 93/12/EEC.

COM(2005)703 final. Further guidance on allocation plans for the 2008 to 2012 trading period of the EU Emissions Trading Scheme. European Commission, 22 December 2005.

IEEP 2006 – Data gathering and impact Assessment for a possible review of the IPPC Directive, Draft Final report, Assignment 7, report produced by the Institute for Environmental Studies and the Institute for European Environmental Policy (IEEP)

IIASA – GAINS energy data for European Member States, <http://www.iiasa.ac.at/web-apps/apd/RainsWeb/>, from scenario "NEC_NAT_CLE3" (NEC03): National baseline scenario as of March 2007.

US Environmental Protection Agency (USEPA) :
Handbook of emission factors Vol 1 – Stationary sources 5th Edition, report AP-42
Method 19 – Determination of sulfur dioxide removal efficiency and particulate matter, sulfur dioxide, and nitrogen oxide emission rates.

VITO 2006, The Environmental Costing Model: a tool to advise policy makers in Flanders on issues of cost efficiency, Meynaerts E., Lodewijks P., Duerinck J., Flemish Institute for Technological Research (VITO)

Appendices

Appendix 1 : Data template

Appendix 2 : Preliminary data for Flanders region of Belgium

Appendix 3 : Completed data templates for selected Member States

Appendix 4 : Member State emission limit values

Appendix 5 : Business as Usual reference scenario data

Fuel use, TJ

Emission factors

CAFE external costs for pollutants and Member States

Appendix 6 : Uncertainty analysis of Member States

Appendix 1 – Data template



"Poland template WN
2_1rs.xls"

Appendix 2 – Flanders combustion facility data

A2.1 Data source

The data on the emission sources are from the Flemish Environmental Agency (VMM). If emissions for one or more pollutants exceed a certain threshold, companies in Flanders are legally bounded to report to the Flemish Environmental Agency. This reporting obligation relates to all emission sources and include typical characteristics such as mass flow, emission concentration, number of operational hours and energy consumption. The database of the Flemish Environmental Agency is used to identify and describe industrial (point) emission sources in the Environmental Costing Model. Other sources of information are literature, surveys and/or contacts with e.g. experts and federations.

A2.2 Number of installations

Preliminary work on the installation data for Flanders is summarised below, the data include information on smaller installations which are required to report emission data in the region. The 20-50 MW_{th} installations are highlighted in red and the data indicate that, for Flanders, over half the installations in the 20-50 MW_{th} range are smaller than 30 MW_{th}.

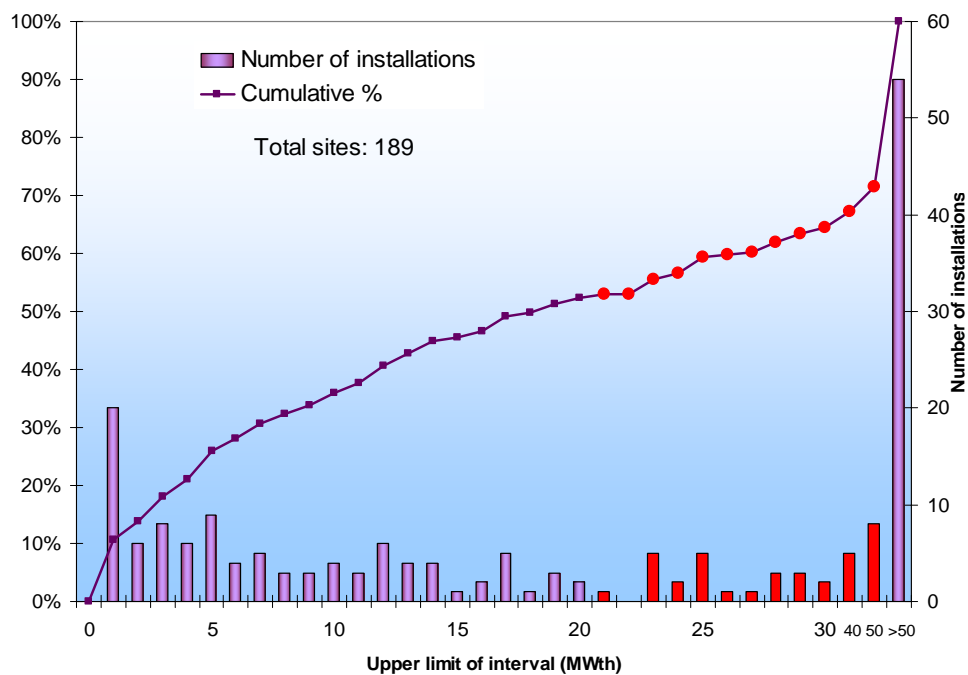


Figure A2-1 Flanders region – number and size of combustion installations.

A2.3 Combustion unit numbers and sizes

Figure A2-2 shows the number of combustion units for each size of installation. Note that the size categories are still aggregated installation capacities.

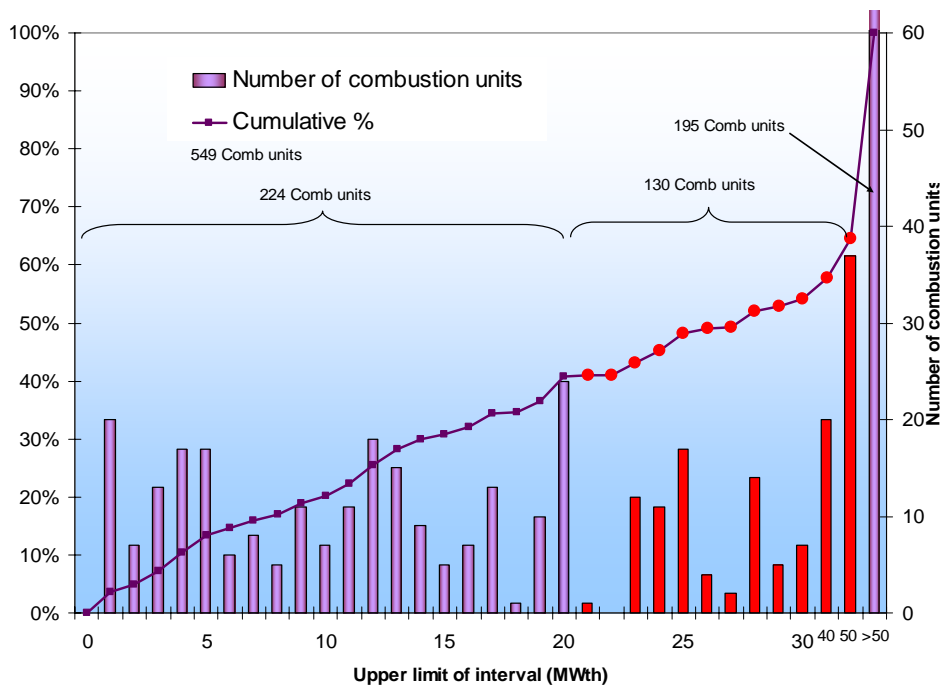


Figure A2-2 Flanders region combustion units

Figure A2-3 provides a summary of all combustion units in Flanders and indicates that about 80% of all the combustion units are less than 20 MW_{th}.

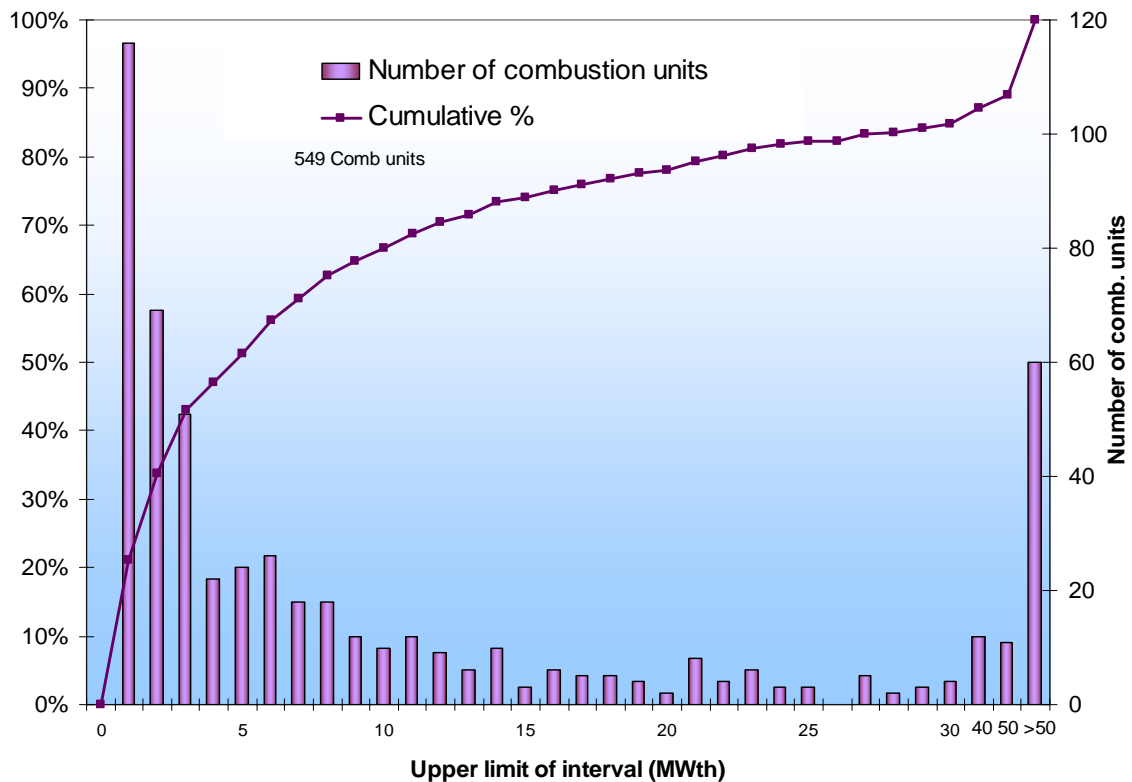


Figure A2-3 Flanders region combustion unit sizes

A2-4 Potential effect of a De Minimis rule

Figure A2-4 illustrates how many installations there are in the different categories when applying a 1 or 3 MW_{th} combustion unit 'de minimis' criteria. The figure indicates that there would be only a minor reduction in the number of 20-50 MW_{th} or >50MW_{th} installations.

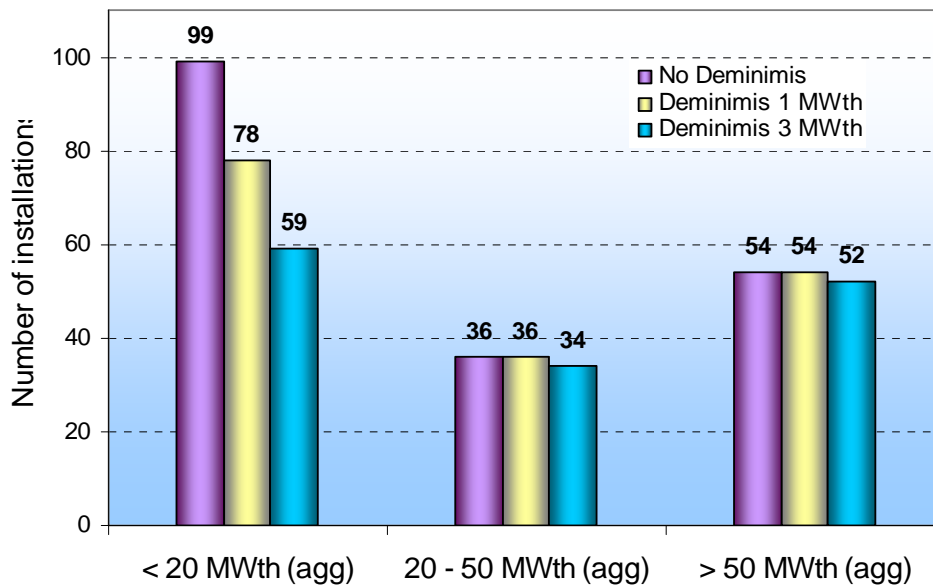


Figure A2-4 Flanders region - Potential impact of De Minimis scenarios on installation population

A2-5 Combustion unit profile in 20-50 MWth Installations

The number of combustion units in 20-50 MW_{th} installations in Flanders are shown in figure A2-5.

Note that the cumulative distribution will always have a shape like that illustrated in Figure A2-5 because of the aggregation rule. That is, the potential for numbers of larger units is constrained by the 50MW_{th} total capacity. The curve of the cumulative percentage is steep in the beginning and flat at the end.

This can be used to define a profile based on three unit categories :

1. Category [0 – 3 MWth] with a reference thermal input of 2 MW.
2. Category [3 – 15 MWth] with a reference thermal input of 10 MW
3. Category [15 – 50 MWth] with a reference thermal input of 25 MW

The definition of a reference installation in the model is very important. A multiple regression analyse (3 independent and 1 dependent variable) shows that these categories of capacity fit the Flemish data very well. It shows that the error on the aggregated capacity is the smallest when for example the largest category has a capacity of [23 MW ± 1,6 MW standard deviation]. When having three categories, it does not make sense to have a reference installation of for example 35 MW.

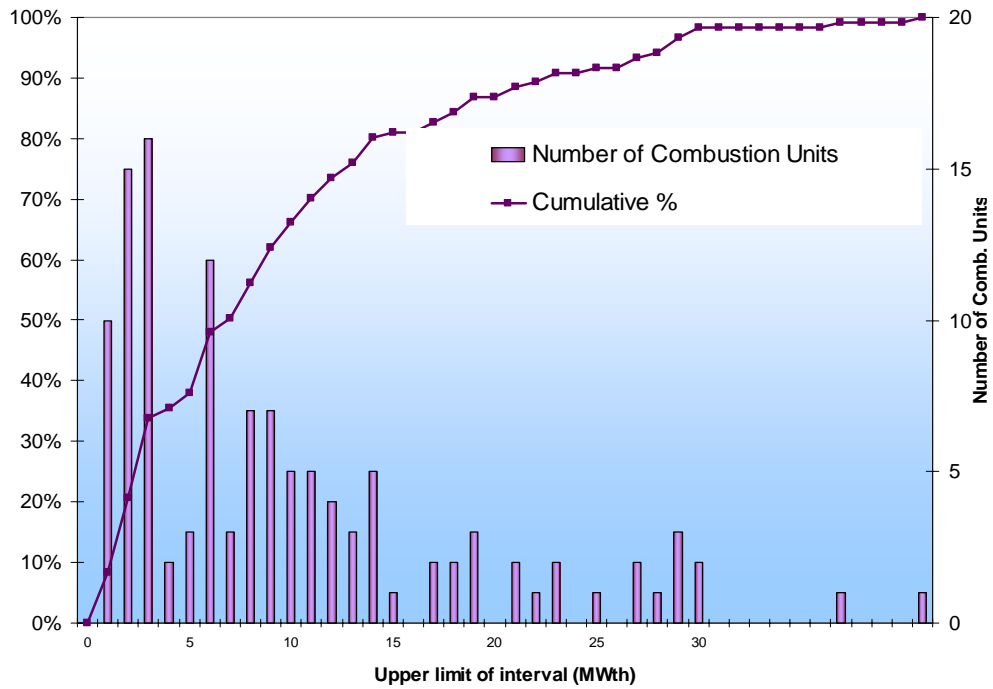


Figure A2-5 Flanders region - Combustion unit sizes in 20-50 MW_{th} installations

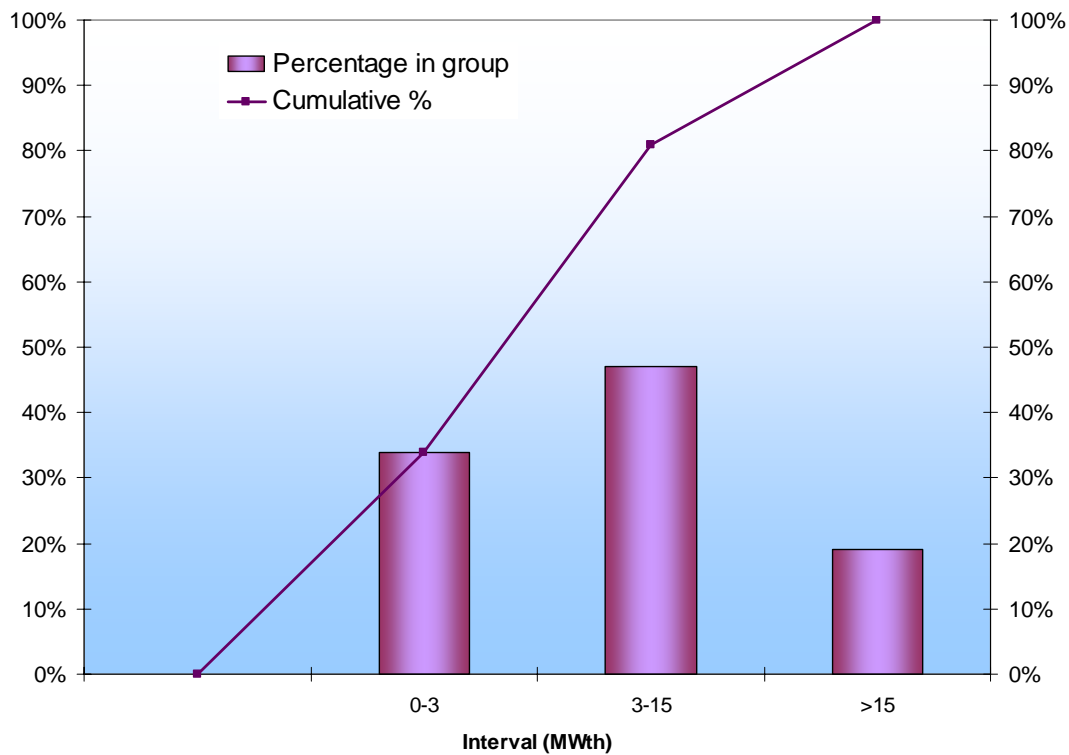


Figure A2-6 Flanders region – Combustion unit size profile for 20-50 MW_{th} installations

A2-6 Differences from ETS data

There is a large difference between ETS data and data of ECM Flanders. In ECM, 36 installations 20-50 MW_{th} are shown with ETS total for Belgium being 108.

Three reasons can explain this difference:

1. Flanders versus Belgium data;
2. Not all companies of ETS are in the Environmental Costing Model, especially sites where a lot smaller combustion units sum up to the lower end of the 20-50 MW_{th} range;
3. The data of ETS has too many 20-50 MW_{th} installations. Collecting data from a 2003 inventory in Flanders with Walloon and Brussels data showed that there are 84 installations.

A2-7 Emissions

Flanders is able to provide emission data for NO_x, SO₂ and PM₁₀ emissions for the non-IPPC 20-50 MW_{th} combustion installations based on national and regional reporting requirements. Note that emission data information for individual installations is not obtainable for most Member States as reporting and emission inventory reporting requirements are different.

The emissions from stationary combustion installations (including the contribution from non-IPPC 20-50 MW_{th} installations) are provided in Figures A2-7, A2-8 and A2-9 (for NO_x, SO₂ and PM₁₀ respectively).

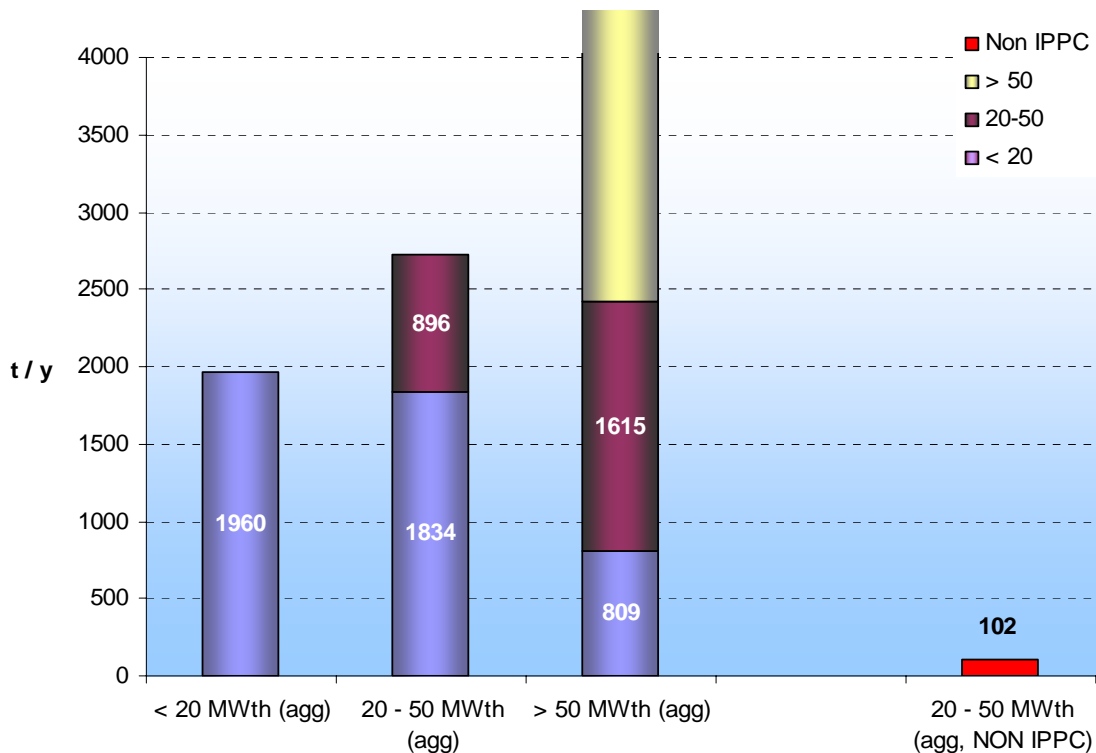


Figure A2-7 Flanders region - NO_x emissions from stationary combustion

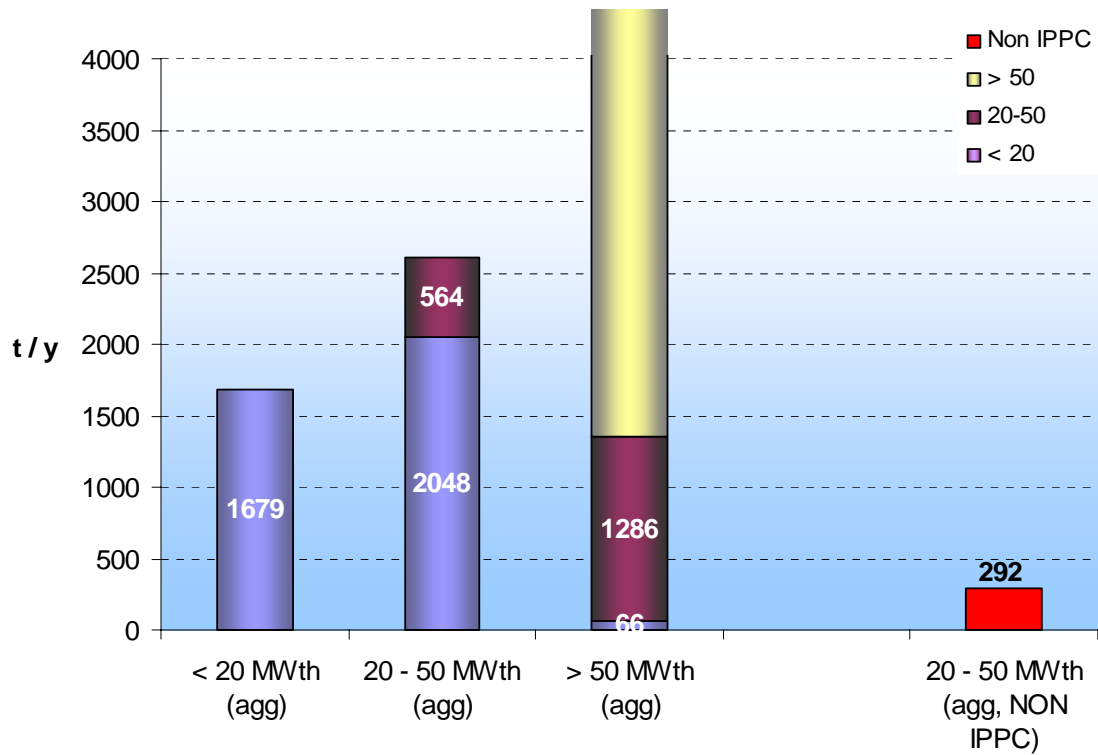


Figure A2-8 Flanders region – SO₂ emissions from stationary combustion

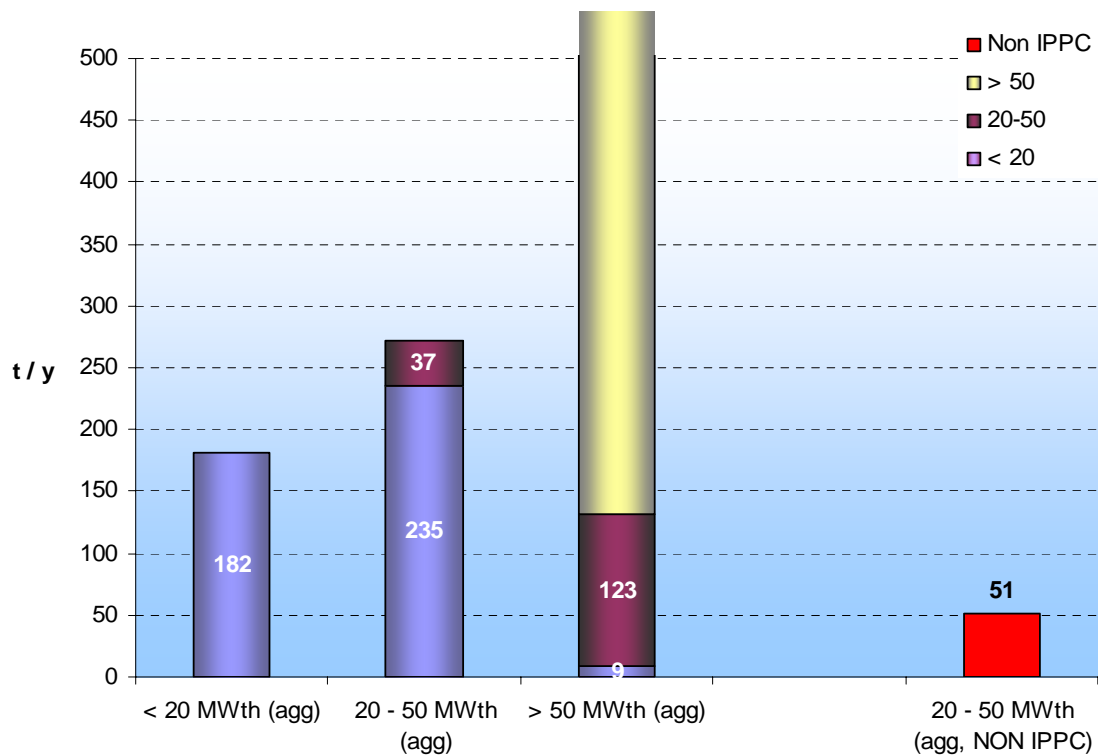


Figure A2-9 Flanders region – PM₁₀ emissions from stationary combustion

Appendix 3 Member State Templates



"UK template
SCU_populatedV1.xls



"Belgian template
SCU.xls"



Slovenija_template_
SCU_SI.xls



Romania_template_S
CU_populatedV1.xls

Appendix 4 Member State ELVs

Table A4.1 – Range of pollutant ELVs for solid fuels (coal)

Country	Size	Reference O ₂ , % v/v dry	Emission concentration, mg/m ³ , dry, 0°C, 101.3 kPa at reference O ₂							
			NO _x		SO ₂		PM		CO	VOC
			Low	High	Low	High	Low	High		
Belgium	0.3-5 MW	6	300	800	1250	2000	50	200	250	
	5-20 MW	6	300	800	1250	2000	50	200	250	
	20-50 MW	6	300	600	1250	2000	50	200	250	
Czech republic	0.2-50 MW	6	650				250		650	50
	<50 MW	6	1500		800	2500			1000	50
France	20-50 MW	6	450	650	850	2000	50	100	200	110
	<4 MW	6	550	825	2000		150			
	4-10 MW	6	550	825	2000		100			
	>10 MW	6	550	825	2000		100			
Finland	1-50 MW	6	275	550	1100	1100	55	140		
Germany	<2.5 MW	7	300	500	350	1300	50		150	
	<5 MW	7	300	500	350	1300	50		150	
	>5MW	7	300	500	350	1300	20		150	
	>10 MW	7	300	400	350	1300	20		150	
Hungary	0.14-50 MW	7	300	650	400	3000	150		250	50
Italy	20-50 MW	6	400		200		30		200	20
Latvia	<10 MW	6	600		2500		1000		2000	
	10-50 MW	6	600		2500		500		2000	
Norway	0.5-1 MW	7	250				100		150	
	1-5 MW	7	250				20		100	
	5-50 MW	7	200				20		100	
Poland	<5	6					630			
	5-50 MW	6					400			
Portugal		6	1500		2700				1000	50
Slovakia	0.2-2 MW	6			2500		250			
	02-50 MW	6					150			
	1-50 MW	6	100		2000		150		100	
	5-50 MW	6					50			
UK	20-50 MW	6	450	650	2000	3000	300		150	
LCPD		6	400		850		50			
BREF		6	90	450	150	400	5	30		

Notes :

All combustion unit sizes are MW_{th} (thermal input).

Range of concentrations (NO_x, SO₂ and PM) generally correspond to ELVs for new and existing combustion plant. Some countries apply BAT achievable emission levels rather than ELVs.

Table A4.2 – Range of pollutant ELVs for liquid fuels

Country	Size	Reference O ₂ , % v/v dry	Emission concentration, mg/m ³ , dry, 0°C, 101.3 kPa at reference O ₂							
			NOx		SO ₂		PM		CO	VOC
			Low	High	Low	High	Low	High		
Belgium	0.3-5 MW	3	300	650	1020	1700	50	200	250	
Belgium	5-20 MW	3	300	650	1020	1700	50	200	250	
Belgium	20-50 MW	3	300	650	1020	1700	50	200	250	
Czech republic		3			1700		100			
Czech republic		3			1700		100			
France	20-50 MW	3	450	650	850	1700	50	100	100	110
France	<4 MW	3	550	825	1700		150			
France	4-10 MW	3	550	825	1700		100			
France	>10 MW	3	500	750	1700		100			
Finland	1-15 MW	3	800	900	1700		50	200		
Finland	15-50MW	3	500	670	1700		50	140		
Germany	HWB	3	180	350			50		80	
Germany	LPS	3	200	350			50		80	
Germany	HPS	3	250	350			50		80	
Hungary	0.14-50 MW	3	450		1000	1700	50	80	175	
Italy	5-50 MW	3	500		1700		100			
Latvia	<10 MW	3	400		1700		50		400	
Latvia	10-50 MW	3	400		1700		50		400	
Norway	0.5-1 MW	3	250				100	100	10	
Norway	1-5 MW	3	250				20	100	10	
Norway	5-50 MW	3	200	600			20	150	10	
Poland	<5	3								
Portugal		3	1500		2700				1000	50
Slovakia	0.2-2 MW	3			1700		100			
Slovenia	1-50 MW	3			1700		50			
Slovenia	5-50 MW	3					50			
UK	20-50 MW	3	200	600	1700		100	150	150	
LCPD		3	400		850		50			
BREF		3	150	450	100	350	5	30		

Notes :

All combustion unit sizes are MW_{th} (thermal input).

Range of concentrations (NO_x, SO₂ and PM) generally correspond to ELVs for new and existing combustion plant. Some countries apply BAT achievable emission levels rather than ELVs.

Note that for SO₂ the ELV for unabated combustion units is determined by fuel sulphur content and Directive 1999/32/EC on sulphur content of certain liquid fuels (1% for Heavy Fuel Oil and 0.2% for gas oil until 1 January 2008 when the gas oil sulphur limit will be 0.1%).

Germany distinguishes NO_x emissions by application, HWB – hot water boiler, LPS – steam boiler supplying steam at temperature up to 210°C and up to 1.8 Mpa, HPS – boilers supplying steam at temperature greater than 210°C or pressure over 1.8 Mpa

Table A4.3 – Range of pollutant ELVs for gaseous fuels (natural gas)

Country	Size	Reference O ₂ , % v/v dry	Emission concentration, mg/m ³ , dry, 0°C, 101.3 kPa at reference O ₂							
			NOx		SO ₂		PM		CO	VOC
			Low	High	Low	High	Low	High		
Belgium	0.3-5 MW	3	200	350	35		50	200	250	
Belgium	5-20 MW	3	200	350	35		50	200	250	
Belgium	20-50 MW	3	200	350	35		50	200	250	
Czech republic		3			35		10			
Czech republic		3			35		10			
France	20-50 MW	3	120	350	35		5		100	110
France	<10MW	3	150	225	35		5			
France	>10 MW	3	100	150	35		5			
Finland	1-15 MW	3	340	400						
Finland	15-50MW	3	170	300						
Germany	HWB	3	100		10		5		50	
Germany	LPS	3	110		10		5		50	
Germany	HPS	3	150		10		5		50	
Hungary	0.14-50 MW	3	350		35	400*	5		100	
Italy		3	350		35		5			
Latvia	<10 MW	3	350		35		5		150	
Latvia	10-50 MW	3	350		35		5		150	
Norway	0.5-1 MW	3	120						10	
Norway	1-5 MW	3	120						10	
Norway	5-50 MW	3	120	200					10	
Poland		3					5			
Portugal		3	1500		2700				1000	50
Slovakia	0.2-2 MW	3			35		10			
Slovenia	1-50 MW	3			35		5			
Slovenia	5-50 MW	3					5			
UK	20-50 MW	3	140		35		5		100	
LCPD		3	150		35		5			
BREF		3	50	100	10		5		100	

Notes :

All combustion unit sizes are MW_{th} (thermal input).

Range of concentrations (NO_x, SO₂ and PM) generally correspond to ELVs for new and existing combustion plant. Some countries apply BAT achievable emission levels rather than ELVs.

Germany distinguishes NO_x emissions by application, HWB – hot water boiler, LPS – steam boiler supplying steam at temperature up to 210°C and up to 1.8 Mpa, HPS – boilers supplying steam at temperature greater than 210°C or pressure over 1.8 Mpa.

* for coke oven gas

Table A4.4 – Range of pollutant ELVs for solid biomass fuels (wood)

Country	Size	Reference O ₂ , % v/v dry	Emission concentration, mg/m ³ , dry, 0°C, 101.3 kPa at reference O ₂							
			NOx		SO ₂		PM		CO	VOC
			Low	High	Low	High	Low	High		
Belgium	0.3-5 MW	3	300	800	1250	2000	50	200	250	
Belgium	5-20 MW	3	300	800	1250	2000	50	200	250	
Belgium	20-50 MW	3	300	600	1250	2000	50	200	250	
France	20-50 MW	11	400	650	200	2000	50	200	250	110
France	<4 MW	11	500	750	200		150			
France	4-10 MW	11	500	750	200		100			
France	>10 MW	11	500	750	200		100			
Finland	1-5 MW	6	250	500			250	375		
Finland	5-10 MW	6	250	500			125	250		
Finland	10-50 MW	6	250	500			50	125		
Germany	<2.5 MW	11	250		350		100			10
Germany	<5 MW	11	250		350		50			10
Germany	>5MW	11	250		350		20			10
Hungary	0.14-50 MW	11	650		1000		150		250	50
Italy		6	400		200		30		200	20
Latvia	<10 MW	6	600		200		1000		2000	
Latvia	10-50 MW	6	600		200		500		2000	
Norway	0.5-1 MW	11	250				100	300	150	
Norway	1-5 MW	11	250				20	300	100	
Norway	5-20 MW	11	200	300			20	100	100	
Norway	20-50MW	11	200	300			20	50	100	
Poland	<5 MW	6					700			
Poland	5-50 MW	6					400			
Portugal		6	1500		2700				1000	50
Slovakia	0.2-2 MW	6								
Slovenia	1-50 MW									
UK	20-50 MW	6	450				300		150	
LCPD		6	400		200		50			
BREF		6	150	300	50	300	5	30		

Notes :

All combustion unit sizes are MW_{th} (thermal input).

Range of concentrations (NO_x, SO₂ and PM) generally correspond to ELVs for new and existing combustion plant. Some countries apply BAT achievable emission levels rather than ELVs.

Table A4.5 – Range of pollutant ELVs for engines (natural gas and liquid fuels)

Country	Fuel & size	Reference O ₂ , % v/v dry	Emission concentration, mg/m ³ , dry, 0°C, 101.3 kPa at reference O ₂							
			Nox		SO ₂		PM		CO	VOC
			Low	High	Low	High	Low	High		
Belgium	gas	5	500	1300						
Belgium	Oil	5	500	4000						
France	gas	5	350							
France	oil	5	1000							
Finland	gas	15	750	1750						
Finland	oil	15	750	2300	600		60	70		
Germany	gas <3 MW	5	1000				20		300	2000
Germany	gas >3 MW	5	500				20		300	650
Germany	oil <3 MW	5	1000				20		300	
Germany	oil >3 MW	5	500				20		300	
Hungary	Gas > 140 kW 4-stroke 2-stroke	5	500						650	150
		5	800						650	150
UK	gas	15	500	750			50	100	450	200
UK	oil	15	1100	1800			100		150	150

Notes :

All combustion unit sizes are MW_{th} (thermal input).

Range of concentrations (NO_x, SO₂ and PM) generally correspond to ELVs for new and existing combustion plant. Some countries apply BAT achievable emission levels rather than ELVs.

Note that for SO₂ the ELV for unabated combustion units is determined by fuel sulphur content and Directive 1999/32/EC on sulphur content of certain liquid fuels (1% for Heavy Fuel Oil and 0.2% for gas oil until 1 January 2008 when the gas oil sulphur limit will be 0.1%).

Table A4.5 – Range of pollutant ELVs for gas turbines (natural gas and liquid fuels)

Country	Fuel & size	Reference O ₂ , % v/v dry	Emission concentration, mg/m ³ , dry, 0°C, 101.3 kPa at reference O ₂							
			NOx		SO ₂		PM		CO	VOC
			Low	High	Low	High	Low	High		
Finland	gas	15	115	175						
Finland	Oil	15	115	175						
Germany	gas	15	75						100	
Germany	oil	15	150						100	
Hungary	Gas	15	150		-				100	
	Oil	15	200		115				100	
UK	gas	15	60	125					60	
UK	oil	15	125	165					60	

Notes :

All combustion unit sizes are MW_{th} (thermal input).

Range of concentrations (NO_x, SO₂ and PM) generally correspond to ELVs for new and existing combustion plant. Some countries apply BAT achievable emission level ranges rather than ELVs.

Note that for SO₂ the ELV for unabated combustion units is determined by fuel sulphur content and Directive 1999/32/EC on sulphur content of certain liquid fuels (1% for Heavy Fuel Oil and 0.2% for gas oil until 1 January 2008 when the gas oil sulphur limit will be 0.1%).

Appendix 5 – Reference case data



"CBA EU27 REF.xls"

Appendix 6 Uncertainty and analysis for scenarios



Scenarios plots

Appendix 7 Operators' and regulators' costs

The sum of the operator and regulators' cost is taken as yearly € 46 333 for every installation. A large part of this sum is the annual £18 736 and the average annual subsistence fees of £ 8 400. An exchange rate to euro is assumed to be 1.5 €/£. For all installations, the yearly operators' and regulators' cost is about 160 M€.

Table A7.1 – Summary of average operators' costs, 2001-2005, (excluding application and subsistence fees), Defra, Mid-term review of the UK's implementation of the Pollution Prevention and Control Regulations, April 2007.

	Overall average	Average based on removal of upper quintile values
One-off average application costs	£48,120	£22,440
Average capital improvements	£307,191	£26,428
Average one-off management time costs	£8,453	£2,992
Average one-off monitoring costs	£12,445	£3102
Average one-off reporting costs	£8,649	£1488
Average 'other' one-off costs	£15,204	£3604
Annual compliance costs	£43,432	£18,736