Cost effectiveness of emissions abatement options in European refineries

Prepared for the CONCAWE Air Quality Management Group by:

P. Roberts (Technical Coordinator)
L. White (Special Advisor)

Brussels
September 2011

ABSTRACT

This report explores the cost-effectiveness of emission reductions in European refineries associated with Best Available Techniques (BAT) and illustrates how Associated Emission Level (AEL) ranges might be derived using a “shadow price”. This methodology is consistent with the Economics and Cross-Media BAT Reference Document (BREF) and closely parallels the technical process underpinning the choice of National Emission Ceilings (NEC).

This report first summarises information gathered by CONCAWE in 2010 concerning the costs of applying candidate Best Available Techniques to reduce emissions from refineries in Europe. Importantly, these costs do account for the retrofitting of equipment to units in existing refineries. The focus is on NO_x and SO_2 emissions from major refinery sources.

Cost data has been expressed as a capital cost, an annualised cost and, with reference to unabated emissions, as a marginal cost. The marginal cost (€/tonne abated) depends on the effectiveness of the technology to be applied and the existing emission. Using the 2006 CONCAWE Sulphur Survey data, the distribution of the incremental marginal cost of different technology applications across the refinery pool has been estimated.

The use of an incremental marginal cost per technology step is central to the GAINS Integrated Assessment Model in deriving cost-effective National Emissions Ceilings for priority pollutants. The Thematic Strategy on Air Pollution (TSAP) set environmental (and consequential emission reduction) targets for 2020 using this methodology and the European Member States accepted the cost of these measures. The average EU cost per tonne of pollutant to be removed has been used as an illustrative "shadow price". Comparing this "shadow price" and the marginal cost curve indicates which abatement techniques could be considered cost-effective and by what proportion of the industry.

KEYWORDS

Industrial emissions, Best Available Technology, combustion, catalytic cracking, sulphur recovery, sulphur dioxide, nitrogen oxides, cost-effectiveness, marginal cost, emissions abatement.

INTERNET

This report is available as an Adobe pdf file on the CONCAWE website (www.concawe.org).

CONTENTS

SUMMARY

This report explores the cost-effectiveness of options for emission reduction in European refineries associated with Best Available Techniques (BAT) and illustrates how Associated Emission Level (AEL) ranges might be derived using a "shadow price". This methodology is consistent with the Reference Guide on Economics and Cross-Media Effects [1] and closely parallels the technical process underpinning the choice of National Emission Ceilings [2]. The focus is on NOx and SO_2 emissions abatement from major refinery sources.

Cost information was gathered in 2010 for some emissions abatement techniques that can be considered as candidate BAT in the refinery BREF. Costs have been expressed as both capital costs and annualised costs. The annualised costs use a policy interest rate of 4% p.a. and a 20 year repayment term, following the IIASA GAINS/RAINS model. These policy assessment assumptions produce lower annual costs than those typically used in the refining sector for making business investment decisions.

Costs have then been represented as a marginal cost (in €/tonne of emissions abated) per incremental technology step. The starting emission for each marginal cost calculation was obtained from the 2006 CONCAWE Sulphur Survey report [3]. As this covers a majority of European refineries, the distribution of the incremental marginal costs of different technology applications across the refinery pool has been estimated. Introducing an incremental marginal cost per technology step is consistent with the GAINS Integrated Assessment Model [2] used to assess National Emissions Ceilings.

Knowing the distribution of marginal costs across the industry informs on the cost-effectiveness of emissions abatement measures for different refinery situations. Following the guidance in [1], the report introduces a "shadow price" – a reference marginal cost based on external factors – to compare with the marginal cost curves.

The "shadow price" for each pollutant is taken to be the EU-wide marginal cost (total incremental cost/total incremental emission abated) of meeting the environmental targets of the Thematic Strategy of Air Pollution (TSAP) [4] as it was evaluated pre-2005 when setting targets for 2020. The reasons for basing the "shadow price" on the TSAP costs are that these reflect a cost-effective means to deliver the environmental goals of the strategy and the negotiated position also reflects the EU Member State agreement to accept the cost of implementing these emission reduction measures.

The superposition of the shadow price and the distribution of marginal cost across the industry identifies a cost-effectiveness decision point for adoption of an abatement options. Abatement measures would, arguably, be cost-justified if the marginal cost were below the shadow price while those above the shadow price would not. Importantly, because marginal cost is defined in terms of incremental emission reduction, this decision point also reflects a particular level of environmental performance. Therefore we can indicate an AEL range that could be considered cost-effective.

The derived AEL ranges shown in this report are an illustration of the possible outcome of the application of this methodology. Clearly, cost-effectiveness in specific cases has to be assessed in detail but this exercise allows a broad perspective on cost-effective BAT AEL ranges to be drawn for the refinery sector.

These illustrative AEL ranges are consistent with the fact-led recommendations already reported in CONCAWE Report 4/09 [5] as shown in **Table 1**.

The left hand columns of the table show AEL range values based on the data collection reported in [5]. These reflect what is practically able to be achieved in a well operated plant. Individual SO_2 AEL ranges for combustion were not proposed. Many refineries operate a refinery bubble for SO_2 and within the scope of either a whole refinery or large combustion plant bubble individual units can have different emissions. Also, no proposal for FCCU SO_2 AEL ranges was made in [5]. This was both because of concern over the lack of predictability of reductions achieved using the popular technology Sulphur Reducing Additives (SRA) and the wide variability in FCCU feed S content. Differences in S content can result from both the source of the feedstock and degree of pre-treatment.

The right hand columns of **Table 1** show the AEL ranges derived using the illustrative cost-effectiveness approach. The TSAP EU-wide shadow prices of 2762 €/t for SO_2 and 1053 €/t for NOx. were used[1]. It is important to note that, at a site level, a "bubble" type approach has been used e.g. total combustion, total sulphur recovery, total catalytic cracking. No cost-effective AEL ranges were derived for NOx abatement using specific techniques (SNCR[2], SCR[3]) using the example starting concentrations of 450 mg/Nm^3 (for combustion) and 750 mg/Nm^3 (for FCCU). These concentrations reflect the upper AEL derived from current performance. For total combustion a range of 162-1000 mg/Nm^3 for SO_2 was derived by considering the options to switch to natural gas or to adopt Wet Gas Scrubbing (WGS). This range was capped at 1000 mg/Nm^3 to reflect the combustion bubble limit present in the Directive on Industrial Emissions (IED) [8]. For the SO_2 emissions from FCCU units, the effectiveness of the SRA has quite a large effect on the cost-effectiveness of WGS giving different upper AEL range values for full-burn and partial burn units respectively. For the Sulphur Recovery Units (SRU), the AEL derived ranges (expressed as sulphur recovery efficiency) imply the need for an upgrade by some of the installed SRU tail gas clean up technology base.

1 The shadow prices were derived using the CONCAWE Integrated assessment model running a simulation of the TSAP [6,7]. These reflect the overall costs of reducing these pollutants to meet the environmental damages caused taking account of all sectoral contributions. Arguably a sectoral approach would show lower shadow prices values for refinery specific impacts.

2 SNCR = Selective Non-Catalytic Reduction

3 SCR = Selective Catalytic Reduction

Table 1 Comparison of performance based AEL range values proposed in CONCAWE Report 4/09 [5] and illustrative values derived from a cost-effectiveness assessment

	Operational data			Cost-Effectiveness		Comment
Application	lower	upper	units	Lower[4]	upper[5]	
Combustion NOx - Gas	50	200	mg/Nm^3		450	No cost effective AEL range based on an initial concentration of 450 mg/Nm^3 was able to be derived from application of SNCR or SCR
Combustion NOx - dual fired (liquid > 50%, N < 0.5%)	300	450	mg/Nm^3			
Combustion SO_2	none proposed		mg/Nm^3	162	1000	Application of WGS or Fuel Substitution by Natural Gas applied to combustion bubble.
FCCU NOx - full burn	300	700	mg/Nm^3		750	No cost effective AEL range identified by this study based on an initial concentration of 750 mg/Nm^3 with respect to application of SNCR or SCR.
FCCU NOx - full burn - residue with Antimony injection	300	1000	mg/Nm^3			
FCCU NOx - partial burn	100	800	mg/Nm^3			
FCCU SO_2 - full burn	none proposed		mg/Nm^3	185	2037	WGS application and SRA @ 40%
FCCU SO_2 - partial burn			mg/Nm^3	185	1383	WGS application and SRA @ 20%
SRU efficiency	99.9	98	%S recovered	99	96.9	For units having recovery < 99%

[4] Lower values of the range reflect assumptions on effectiveness and starting concentrations
[5] Upper values of the range may indicate unabated generic emissions in the event that the cost-effectiveness argument did not identify a limit lower than the initial assumptions.

1. INTRODUCTION

This report describes work carried out to define the cost and incremental marginal cost of techniques for abating the pollutants Nitrogen Oxides expressed as NO_2 (NOx) and Sulphur Dioxide (SO_2) from refinery sources and to arrive at cost-effective Best Available Technique (BAT) Associated Emission Level (AEL) ranges. To do this a shadow price derived from preparatory work for the Thematic Strategy on Air Pollution (TSAP) is used.

The work is carried out to support the revision of the Reference Guide to Best Available Techniques as applied in European refining. At the same time the information is also relevant to the parties involved in negotiating the review of the Gothenburg Protocol, via the Expert Group on Techno-Economic Issues (EGTEI) as part of their work to support the Convention on Long Range Transport of Air Pollutants (CLRTAP), as well as to European Community Member States considering new National Emissions Ceilings (NEC) under the NEC Directive.

The Convention and the European Commission adopt an Integrated Assessment approach in their analysis. This approach aims to find the most cost-effective means of reducing those pollutant emissions that contribute to environmental damage to achieve specific environmental goals (e.g. reduction of harm to human health, ecosystem protection) via use of the GAINS model. Policy decisions made using this methodology usefully also provide a reference point for assessing marginal abatement costs on a sector by sector basis. Similarly, under the new Directive on Industrial Emissions (IED) (as under Integrated Pollution Prevention and Control (IPPC)) there is a requirement that a technique can only be considered to be BAT when it can be implemented “in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages” (IED Article 3.10 (b)). This implies, in line with the guidance provided in the Cross-Media and Economics BAT Reference Document (BREF) [1], that costs for applying a technique should be proportionate to the environmental benefits achieved. Thus information on marginal costs is a critical input to the permit writing process.

The acquisition of detailed cost data is a sensitive task which has to be conducted according to competition laws. Accordingly, CONCAWE adopted an approach, based upon information gathered previously by EGTEI, that allowed Member Companies to provide information in an anonymous way, based on real data but presented in such a way that individual sites/companies could not be inadvertently revealed by the disclosure of unique unit characteristics. The base references are the EGTEI synopsis sheets (3/11/2005 version) for:

- Combustion process
- Fluidised Cracking
- Sulphur recovery

Initially CONCAWE asked for Member Company comments on the EGTEI data, which includes both capital and operating costs, for a specific size (capacity) of unit. Scaling rules were provided so that data could be compared on a common basis. This process both eases the comparison of responses but also removes information that could identify a specific site. All responses were treated confidentially and anonymously. Companies were asked to provide a cost ratio to the EGTEI data rather than specific figures. Two specific requests were made.

- Costs should be assessed relative to the local situation in Europe (construction costs). A clear distinction should be made between new build and retrofit application. Retrofit is the more representative case in Europe but introduces potentially large cost ranges depending on, for example, availability of plot space which can significantly impact the cost of installing new units.
- Annualised costs should be derived using the interest rate (4%) and repayment term (20 years) used in European policy assessments. These are not typical values used by the sector[1]. As a result the annual costs presented here are lower than the industry would use in normal business decision-making.

The data CONCAWE collected was processed and submitted (February 2011) to EGTEI for use in the Gothenburg Protocol Revision. The new numeric values were the result of multiplying the synopsis sheet data by the "uplift" factors returned from the company survey. These uplift factors ranged from one to more than six for the capital cost of projects and generally were around one for the operating cost associated with the techniques. The significant uplift in capital cost reflects the fact that the EGTEI data is largely based on the basic cost of the abatement technology from the vendor rather than the total installation cost i.e. the additional costs associated with integrating the specific abatement technology into the existing refinery facilities and the associated offsite costs. These are often the largest contributors to the overall project cost. An additional factor is the rises in project costs (labour, materials) since 2005.

This EGTEI information was also provided in February 2011 to the European Industrial Pollution Prevention and Control Bureau (EIPPCB) and in April 2011 to the full Technical Working Group (TWG) for use in the refinery BREF review.

The transparency requirements of the Sevilla process[2] would ideally require the origin of the data to be released. This is not possible according to the terms of the competition law compliant agreement on data collection. Instead, in this paper CONCAWE has added information on the number of data submissions and their distribution within the uplift range. For example if a range comprises three similar values and one different value then this is identified.

The cost-data has been combined with activity data to estimate the cost-effectiveness of different abatement technologies or techniques (e.g. fuel substitution). The capital cost ranges used in the overall cost and cost-effectiveness analysis are based on the detailed CONCAWE Member Company data but have been further constrained by limiting the “EGTEI uplift factor” to a maximum of three for the lower range and a maximum of five for the upper range. Clearly in specific situations, the submitted data indicates higher uplifts are appropriate.

The activity data derives from the CONCAWE survey of sulphur pathways for the year 2006 [3]. This survey is run at four yearly intervals to gauge progress by the industry in reducing emissions, what the emission sources are and how the S content of refinery products is distributed. Importantly:

- The survey covered more than 2/3 of the EU refinery throughput in 2006.

[1] The equivalent capital charge is 7.4% compared to a typical sectoral range of 11-15%.

[2] The Sevilla process is the exchange of information between Member States and Industries involved on the dynamic concept of BAT, associated monitoring and future developments. The concrete product of the process is a BREF document.

- Detailed data from some 400+ refinery combustion plant stacks; including quantity and sulphur content of fuels fired, was available.
- Detailed data from 33 Fluidised Catalytic Cracking Units (FCCU's); including design and actual throughput of fresh feed, sulphur in fresh feed, sulphur emitted to the atmosphere, was used.
- Detailed data from 56 Sulphur Recovery Units (SRUs); including design and actual throughput, quantity of sulphur recovered and quantity emitted to the atmosphere (hence recovery efficiency).

This high level of refinery coverage, combined with the availability of detailed data at individual stack level or individual process unit level provides a statistically robust and representative view of both cost and cost effectiveness implications of BAT application in European Refineries.

In this report we also estimate cost-effectiveness for NOx abatement measures. Although the sulphur survey does not gather information on NOx emissions it is a reasonable assumption that the technology "Low NOx burners" is already applied to most of the combustion plant in European refineries. We assume that baseline NOx emissions can be calculated assuming use of low NOx burners and using information on the refinery fuel mix.

The estimates of NOx emissions from FCC units are a little more uncertain due to the possibility of different FCC configurations and design. To assist this assessment data from the first official draft release of the refinery BREF (D1 release) was used. This draft contains data on refinery emissions gathered by the EIPPCB in bilateral discussions with individual refineries. The refineries are anonymous and not known to CONCAWE but statistical analysis is possible. The CONCAWE Sulphur Survey for year end 2010 will gather FCCU NOx data explicitly and will be reported separately.

2. COST OF ABATEMENT FOR REFINERY COMBUSTION PROCESSES

2.1. SO_2 ABATEMENT

Two abatement technologies were considered for reducing refinery SO_2 emissions. These are Wet Gas Scrubbing (WGS) and the substitution of refinery fuel oil by Natural Gas (NG).

The basic assumptions and cost survey results for a wet gas scrubber are:

- Removal efficiency should be 90%.
- The reference capital cost range for a 50 MW Unit is: 8-16 M€. This range represents an uplift of between 2 and 4 times the EGTEI (2005) value.
- The annualised capital charge is 7.4% (equivalent to a 4% interest rate applied over a 20 year write-off).
- The scaling rule for cost of a unit sized MW compared to the reference unit is given by: $\frac{Cost\ of\ unit\ [MW]}{Cost\ of\ Reference\ Unit} = \left(\frac{MW}{MW_{ref}}\right)^{0.6}$
- The reference fixed operating cost is 4%/y of the capital cost.
- The reference variable operating cost is 433 k€/year.

There are a number of factors affecting the cost of natural gas substitution. Importantly we have considered gas to be available. This is not the case for all European refineries. When a refinery imports natural gas it is replacing an internal non-commercial fuel with an import and the cost depends upon the differential between the purchase price of the imported gas and the market value of the internal fuel it is displacing. To this must be added the annualised capital cost of any facilities that have to be constructed to bring the gas into the refinery fuel gas system. Combustion modifications may also have to be carried out to adapt boilers and heaters. As there is no sure means of assessing these factors we will treat this scenario using two values of potential cost increment. Given the significant potential for variation in these cost elements from site to site, in this study we have assumed a range of incremental costs. The range tested is from 50 to 100 €/t_{FOE}, where Fuel Oil Equivalent (FOE) denotes a fuel oil equivalent energy content of 41.86 GJ/t.

Figure 1 shows a plot of costs for wet gas scrubbing based upon the central value of the above range (12 M€ @ 50 MW_{th}) as a function of unit size. The upper blue curve is the investment cost (M€) read to the left vertical axis and the lower pink curve is the annualised cost (k€/a) read to the right hand vertical axis.

Figure 1 Abatement Costs (Investment and Annualised) for Wet Gas Scrubbing on Refinery Combustion Equipment

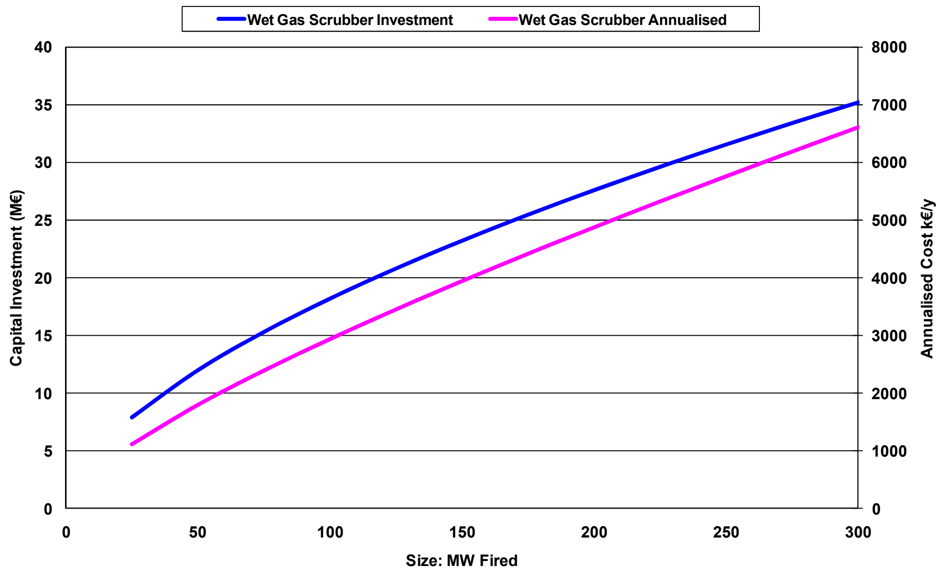
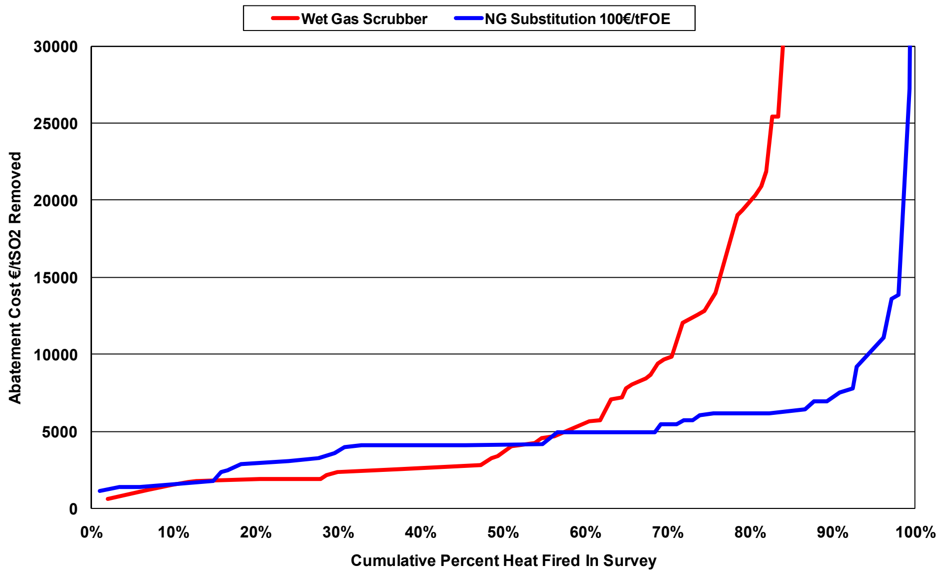


Figure 2 shows the same data converted to marginal cost using the following procedure. The CONCAWE sulphur survey [3] provides information on the refinery fuel mix (gas relative to oil) and the contribution of each fuel to refinery SO_2 emissions. The survey provides information on how emissions are distributed by stack size using broad categories (< 50 MW, 50-100 MW, 100-300 MW and > 300 MW). These survey data have been supplemented by additional, more highly resolved, information on the stack size distribution. It is therefore possible to estimate, refinery by refinery, how much SO_2 (tonnes/a) could be removed from stack treatment by applying Wet Gas Scrubbing applied to stacks (> 50 MW) and what the annualised cost of doing so would be. Dividing the cost of applying the technique by the sulphur removed gives an incremental cost in €/t SO_2 represented on the vertical axis.

An alternative to applying Wet Gas Scrubbing is to substitute the fuel oil used for combustion with natural gas noting that the refinery also uses internally generated gases as fuel and this refinery fuel gas cannot be substituted. There are several considerations to be taken account of when considering fuel switching, see **Appendix A**. The price differential of natural gas to the export value of refinery fuel oil is market driven and future prices cannot be known. We have used an example differential of 100 €/tonne of FOE.

Figure 2 Marginal costs of abatement calculated from CONCAWE activity data and costs and for the substitution of fuel oil firing by Natural Gas assuming a price differential of 100 € /tonne$_{FOE}$



The horizontal axis reflects the number of refineries for which the calculation has been possible. These have been ordered in the direction of increasing marginal cost. Because the relevant parameter is the amount of fuel consumed, the refinery cumulative fuel consumption is expressed in energy terms. Alternatively the cumulative number of affected refineries could be plotted but this would lose information on refinery size.

In this and in subsequent graphs the horizontal range shown as 0-100% refers to the "pool" of refineries for which the technique is applicable. Where more than one technique is shown on a graph then the pools are not necessarily the same for each technique. For this example wet-scrubbing could be applied to refineries whether they fire fuel oil or fuel gas. Clearly for a fuel-gas fired refinery the marginal cost becomes very high because the amount of sulphur removed is small. The pool of refineries for which fuel switching is applicable is somewhat smaller as it comprises only those refineries currently burning fuel oil.

Figure 2 shows that, for wet gas scrubbing, the marginal cost of abatement increases relatively slowly up to about 4000 €/t for about half of surveyed refinery total fuel consumption and then increases more rapidly. Broadly speaking the best cost efficiency lies with those refineries having the largest abatable combustion SO_2 emissions.

The marginal cost of switching from fuel oil to natural gas at a price premium of 100 €/tonne$_{FOE}$ is also shown in **Figure 2**. These figures are based only on the energy cost differential. No account is taken of the costs of installing a suitable natural gas connection to the refinery fuel gas system and it is assumed that NG is available. The price premium is notional as the future price of both fuel oil and natural gas is unknown. One important factor for refiners considering fuel switching is the future price and price stability of gas.

For natural gas substitution, another key factor affecting the marginal cost very much depends on the amount of sulphur in the existing fuel oil firing. It increases more or less steadily as the amount of fuel oil sulphur substituted decreases, becoming extremely large for near fully gas-fired sites[3].

2.2. NO_X ABATEMENT

Two technologies were considered for NOx abatement, Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). In accord with the GAINS methodology the marginal cost calculation considered these to be complementary alternative steps. Justification of the more expensive SCR step rather than the SNCR step is based on the incremental cost over incremental NOx removed meeting the cost-effectiveness criteria, that is, the refinery would consider implementing low NOx burners before SNCR and SNCR before SCR. Marginal costs are therefore based on the incremental performance between technologies.

As explained in the introduction, the assumptions and results of the cost survey were:

- A majority of combustion units already have low NOx burners in place and these achieve emissions of:
  - 200 mg/Nm^3 for gas-firing[4] and
  - 450 mg/Nm^3 for oil firing, both expressed at 3% oxygen in dry flue gas.
- The annualised capital charge is 7.4% (equivalent to 4% interest over a 20 year write-off period).
- The reference fixed operating cost is assumed to be 4%/year of the capital cost.
- The scaling rule for cost of a unit sized MW compared to the reference unit is given by: $\frac{Cost\ of\ unit\ [MW]}{Cost\ of\ Reference\ Unit} = \left(\frac{MW}{MW_{ref}}\right)^{0.6}$

The specific information about SNCR was:

- The removal efficiency is in the range 30-70% taking account of variable performance shown in retrofit applications.
- The reference capital costs of a 50 MW Unit are between 0.6 and 1.3 M€.
- The total operating costs for a 50 MW Unit (fixed and variable) are between 40 and 100 k€/a.

The specific information for SCR was:

- The removal efficiency is 85%.

[3]. For refineries at the high end of the marginal cost curve where the amount of substituted fuel, and hence gain in emission reduction, is small then the actual cost of substitution could be low provided that natural gas is already used in the refinery fuel gas system and outlets for the displaced refinery fuel are in place.

[4] The NOx emission values are at the high end of the ranges proposed in [5] with the effect that the marginal cost to the next technology step may be underestimated.

- The reference capital costs of a 50 MW unit are between 4.3 and 8.5 M€.
- The fixed operating cost of the reference unit is 4%/year of the capital cost.
- The variable operating costs for a 50 MW unit are 64k€/year.

Results are shown in **Figure 3** on an investment (upper two curves read to the left hand scale) and on an annualised basis (lower two curves read to the right hand scale) as a function of stack size. The mid-values of the cost-ranges have been used.

Figure 3 Abatement Costs (Investment and Annualised) for NOx reduction from Combustion Equipment

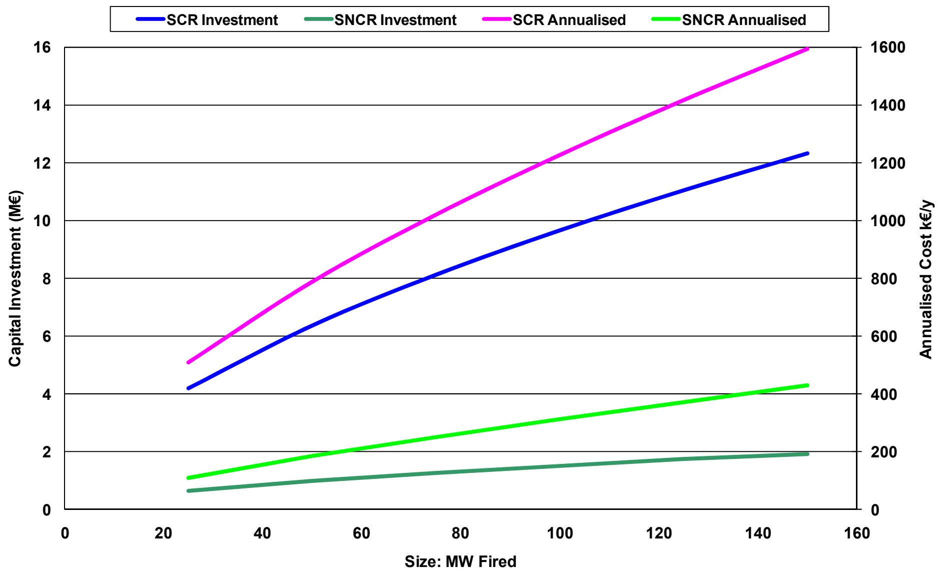


Figure 4 shows the marginal cost of abatement achieved using SNCR assuming the mid-range efficiency of 50% and mid-range of costs followed by the incremental step to SCR. SNCR efficiency depends on a number of conditions and might not be as high as 50%. **Figure 5** assumes a lower SNCR efficiency. However, it is evident that SNCR offers the more cost-effective means of NOx reduction of the two techniques, the more so if the upper efficiency bound of 70% can be attained.

The marginal cost by the SCR route (either directly or following SNCR) is very variable across the refineries increasing by a factor of ~5 from most to least cost-effective.

Figure 4 Marginal Cost of Abatement assuming SNCR a first step and SCR a second, assuming that all units are equipped with low NOx burners. SNCR removal efficiency 50%

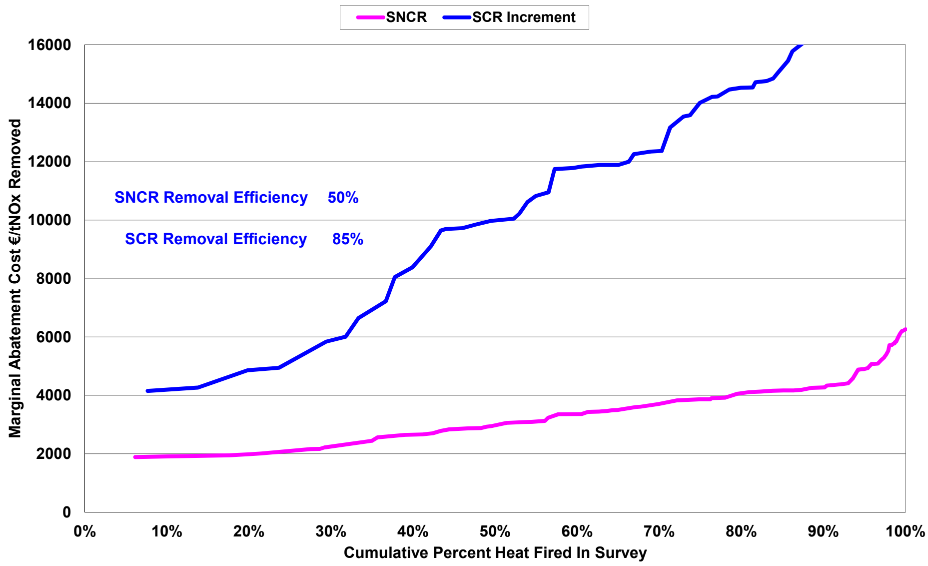
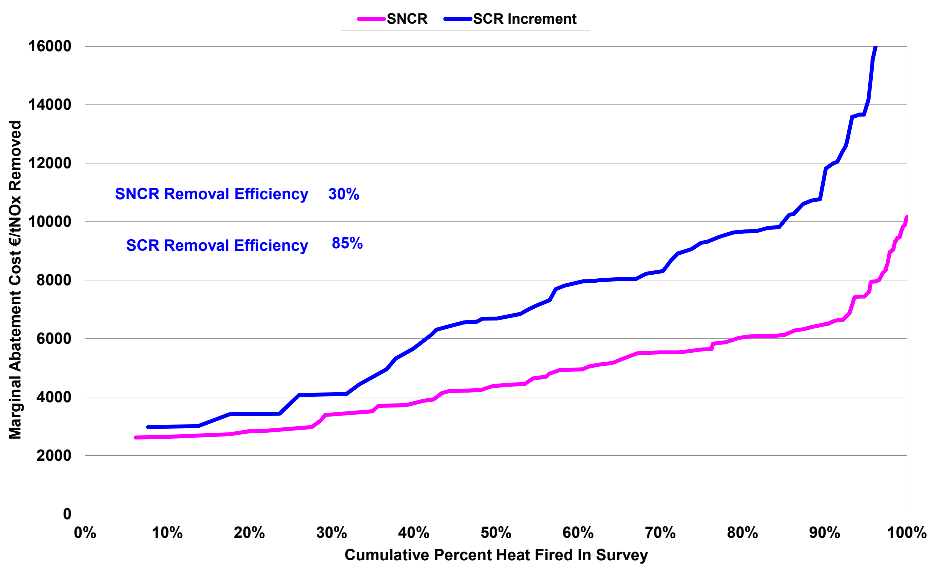
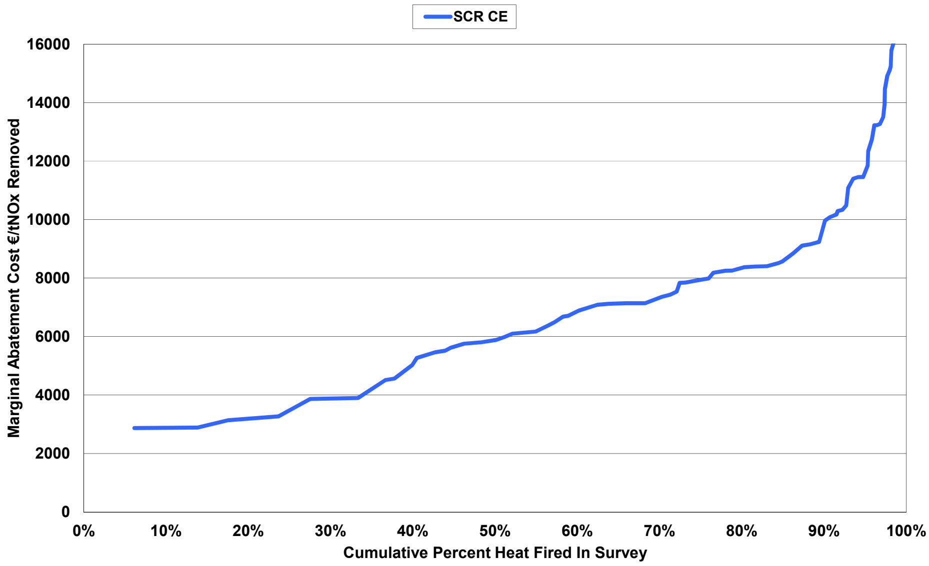


Figure 5 Marginal Cost of Abatement assuming SNCR a first step and SCR a second, assuming that all units are equipped with low NOx burners. SNCR removal efficiency 30%



The applicability of SNCR depends on a number of conditions being met, most importantly the temperature window. We have calculated the case where only SCR is applicable and the results are shown in **Figure 6**.

Figure 6 Marginal Cost of Abatement assuming that only SCR is applicable



3. COSTS OF ABATEMENT FOR FLUIDISED CATALYTIC CRACKING

Many European refineries have a FCCU and this can contribute a large proportion of overall site emissions. In a FCCU the normal operation results in the deposition of carbon (coke) on the catalyst which inhibits the catalytic action. The catalyst is then regenerated. Emissions to air from the regenerator are the main concern. The regenerator can be a "full burn" unit where the objective is to fully combust all of the coke in the regenerator itself (with essentially no carbon monoxide in the flue gases leaving the regenerator) or a "partial burn unit" where the off-gases from the regenerator are taken into a separate combustion section where they are co-fired with supplementary fuel to destroy the CO and to raise steam. Full burn units may also have a fully fuel fired auxiliary boiler to utilise the heat energy in the FCCU waste gas. The operation and environmental performance of the FCCU can also be altered by the use of additives. There are three types: those that promote the formation of CO and hence enhance the energy efficiency of partial burn units by increasing the fraction of coke energy released in the auxiliary boiler, those that promote the destruction of NO_x and those that promote the retention of SO_2.

3.1. SO_2 ABATEMENT

The two abatement technologies considered for SO_2 removal are the application of a de-SOx Catalyst Additive (Sulphur Removal Additive (SRA)) and Wet Gas Scrubbing (WGS). The assumed removal efficiencies reflect averaged performance over a year.

The key assumptions (following [3]) are:

- The removal efficiency of the additive Sulphur Reducing Additive (SRA) is in the range[5] 20-40%. This is a fairly wide range because experience shows that the performance of additives is different in full burn (more effective) than in partial burn units and is also dependent on other process characteristics, e.g. the use of antimony injection (see [5]).
- The removal efficiency of WGS is 90%.
- The annualised capital charge is 7.4% (equivalent to 4% interest over a 20 year write-off period).
- The reference fixed operating cost is assumed to be 4%/year of the capital cost.
- The scaling rule for cost of a unit sized M compared to the reference unit of 2 Mt of feed per year is given by: $\frac{Cost\ of\ unit\ [MW]}{Cost\ of\ Reference\ Unit} = \left(\frac{M}{M_{ref}}\right)^{0.6}$

The cost information obtained from Member Companies showed that

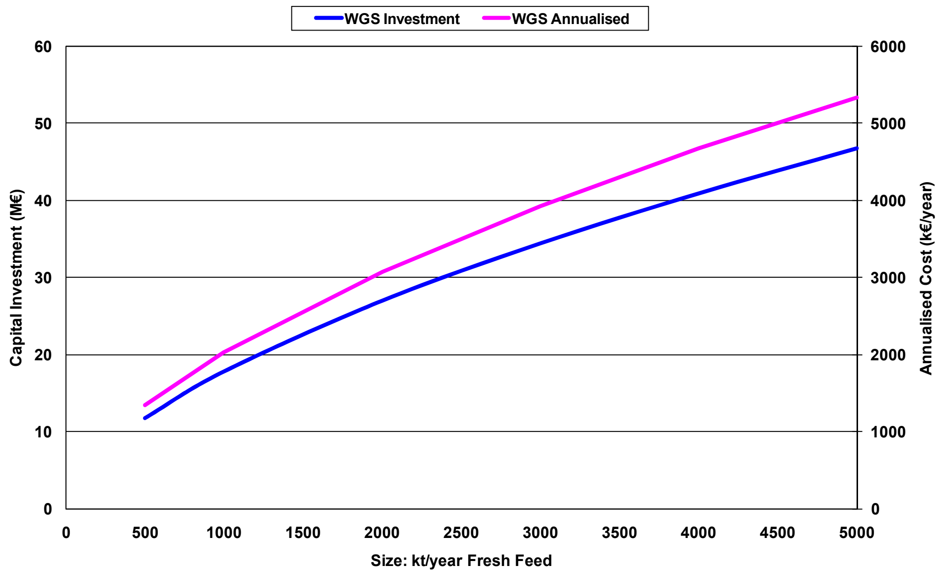
- The reference capital costs for a 2Mt Feed/y Unit were for the use of the SRA 0.5 (M€); and for the application of WGS 16-36 (M€).

[5]This is a narrower range than quoted in [5] as it is not clear that the upper range of 60% efficiency reported for some units can be widely achieved.

- The variable operating costs were: SRA: 1.25 €/$t_{Fresh\ Feed}$ and for WGS: 0.93 €/$t_{Fresh\ Feed}$ which equate to 2.5 M€/a and 1.8 M€/a respectively for the reference unit. These costs are unchanged from the EGTEI values.

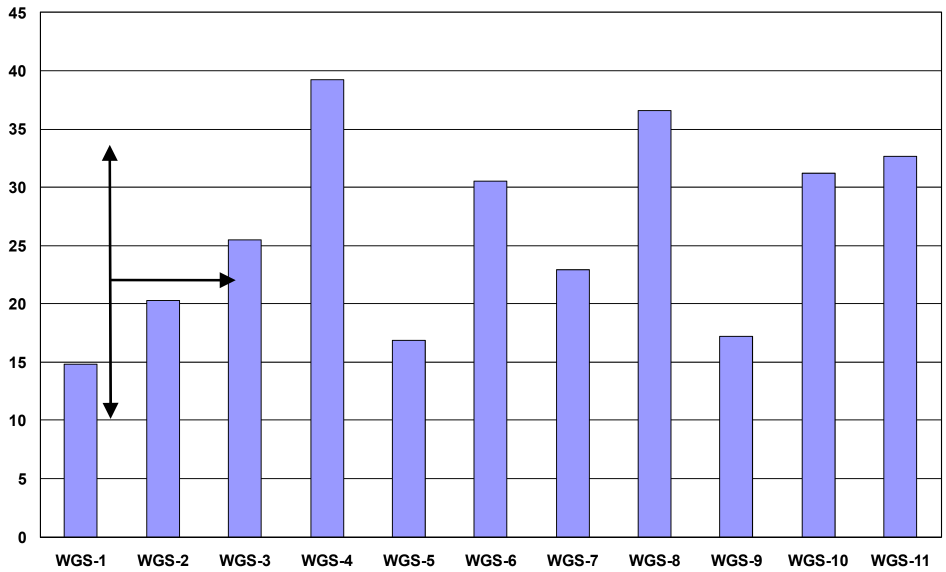
The variation in cost with unit size (capital to the left vertical axis, annualised to the right vertical axis), for Wet Gas Scrubbing is shown in **Figure 7**. The mid-value (26 M€) of the surveyed range has been used as a reference point.

Figure 7 Capital cost and annualised cost for a Wet Gas Scrubber installed on a FCC Unit



If there were sufficient data to describe costs statistically then the variation about the mid-range would typically be described as the distance between the 5^{th} and 95^{th} percentiles. Instead the range was taken to lie just within the maximal and minimal values. **Figure 8** shows how the values of 11 FCCU WGS projects were distributed across the derived range. The mid-range value of 26 and the chosen range bounds are indicated. Of the 11 projects 6 had costs between the mid and the lower range bounds and 5 above. There was no obvious grouping or outlier.

Figure 8 Distribution of Wet Gas Scrubbing Costs within the Cost Survey data. All costs scaled to a unit size of 2 Mt of fresh feed per year. The mid value (26 M€) and range (16-36 M€) are indicated



The marginal cost curves are shown in **Figure 9** and in **Figure 10** for two values (40%, 20%) of SRA effectiveness respectively. In keeping with the RAINS methodology the cheaper (SRA) mitigation step is assumed to be applied first. As the operational performance of the SRA depends on whether the FCCU is a full burn (40% removal) or partial burn design (20% removal), and WGS is applicable to both, the marginal cost curves have been calculated for both values of performance. In a majority of units the application of SRA is clearly low cost. The marginal cost only becomes high for units treating very low sulphur content feed[6]. It should be noted though that the technical feasibility of SRA needs to be tested on a site by site basis. In the CONCAWE data collection, efficiency was found to vary between 20% and 60% and the reason for this wide range in observed performance is not known. The marginal cost of WGS as an incremental step is very dependent on the FCCU mode of operation, being greater for the full-burn case.

[6] The S content of the feedstock can depend on pre-treatment. We have not considered feed hydro-treatment as an abatement technology because it is used to control the FCC product composition in the first instance and the benefit for emissions is consequential.

Figure 9 Marginal Abatement Cost curves assuming high effectiveness (40%) of the SRA applied in full burn FCC units. The mid-range cost of applying Wet Gas Scrubbing was assumed

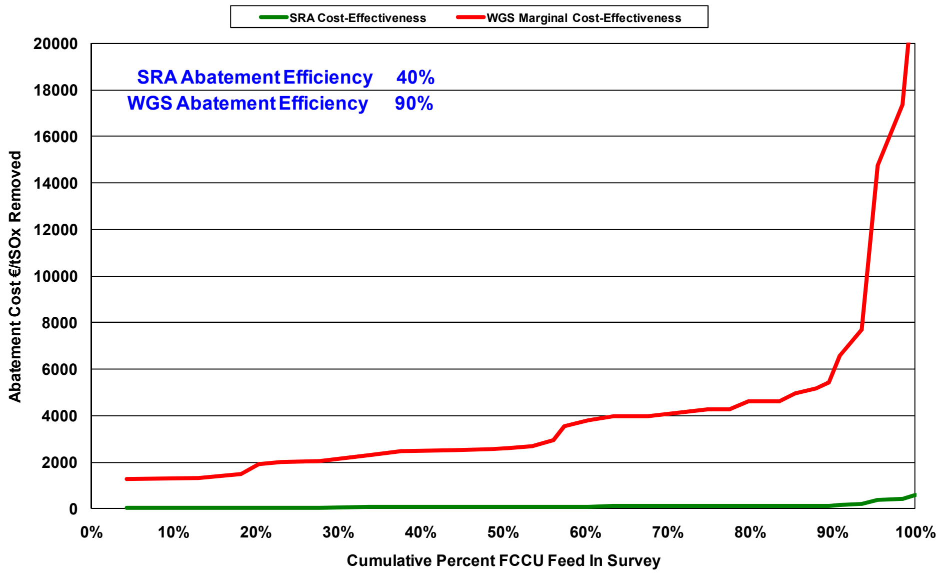
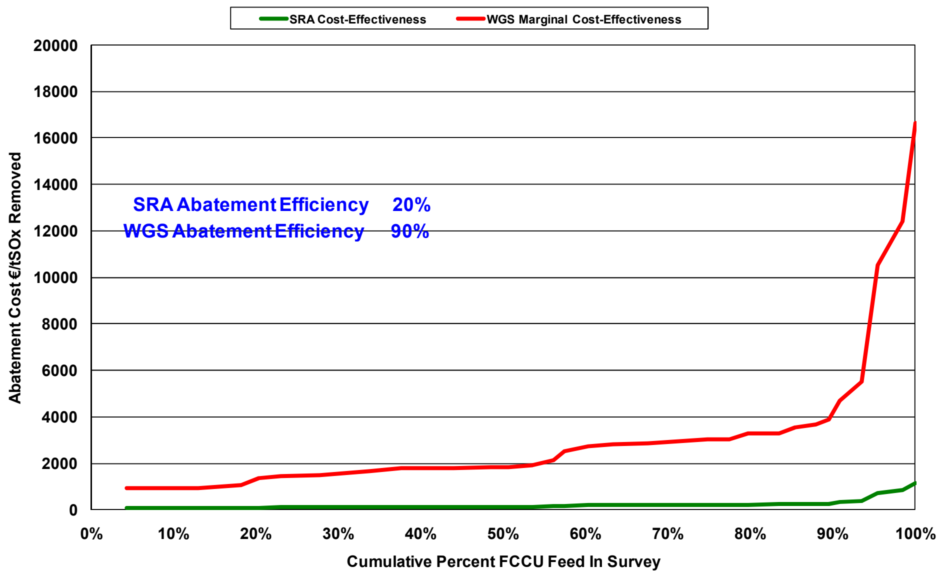


Figure 10 Marginal Abatement Cost Curves assuming low effectiveness (20%) of the SRA applied in partial burn FCC units. The mid-range cost of applying Wet Gas Scrubbing was used



3.2. NOx ABATEMENT

In this section we examine NOx abatement techniques focusing on SNCR and SCR. It is important here to note that SNCR is not applicable to FCCU full-burn units unless they are equipped with an auxiliary boiler because the temperature at the regenerator outlet is too low to enable SNCR. In the case of partial burn, the necessary presence of a CO boiler provides a suitable temperature window for SNCR. However, the NOx reduction efficiency is highly variable.

The common assumptions made are as previously. The reference unit processes 2 Mt/a feed.

- The annualised capital charge is 7.4% (equivalent to 4% interest over a 20 year write-off period)
- The reference fixed operating cost is assumed to be 4%/year of the capital cost
- The scaling rule for cost of a unit sized M compared to the reference unit of 2 Mt of feed per year is given by: $\frac{Cost\ of\ unit\ [M]}{Cost\ of\ Reference\ Unit} = \left(\frac{M}{M_{ref}}\right)^{0.6}$

The specific assumptions following data from CONCAWE (2010) are that:

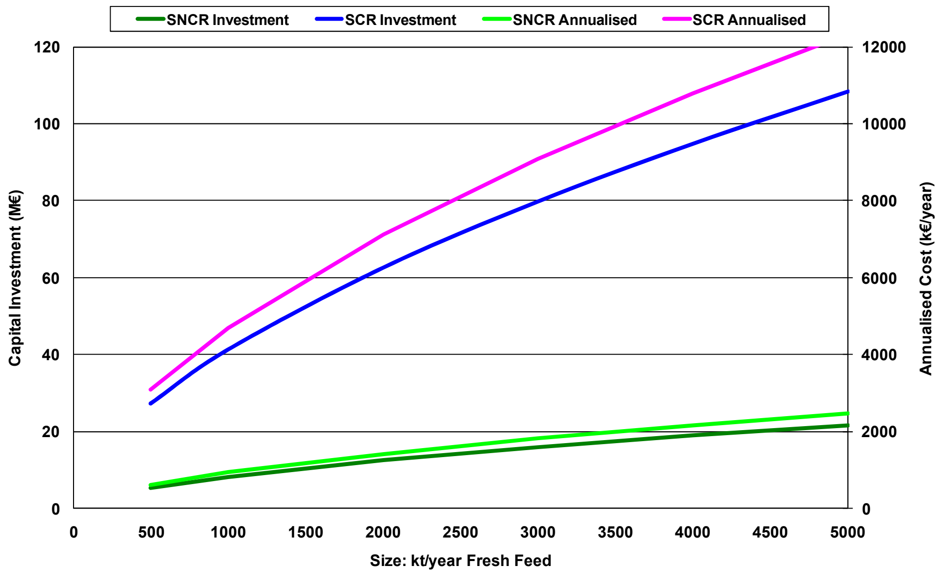
- The removal efficiency for SNCR is in the range 20-70% and for SCR it is 85% - both on an annual basis.

The cost information gathered from member companies is that the:

- Reference capital costs for the 2Mt/y Unit are 10-15 M€ for SNCR and 50-75 M€ for SCR. These represent an uplift of a factor 2 and 15 upon the EGTEI costs. The result for SCR was at first surprising but we now believe that the EGTEI synopsis sheet, which refers to both SNCR and SCR, but distinguishes neither, is either based on an assessment of SNCR costs and/or represents vendor only costs for the equipment, omitting the installation component.
- Variable operating costs are 0.37 €/$t_{Fresh\ Feed}$ for SNCR and 0.177 €/$t_{Fresh\ Feed}$ for SCR. These are the same as those given by EGTEI.

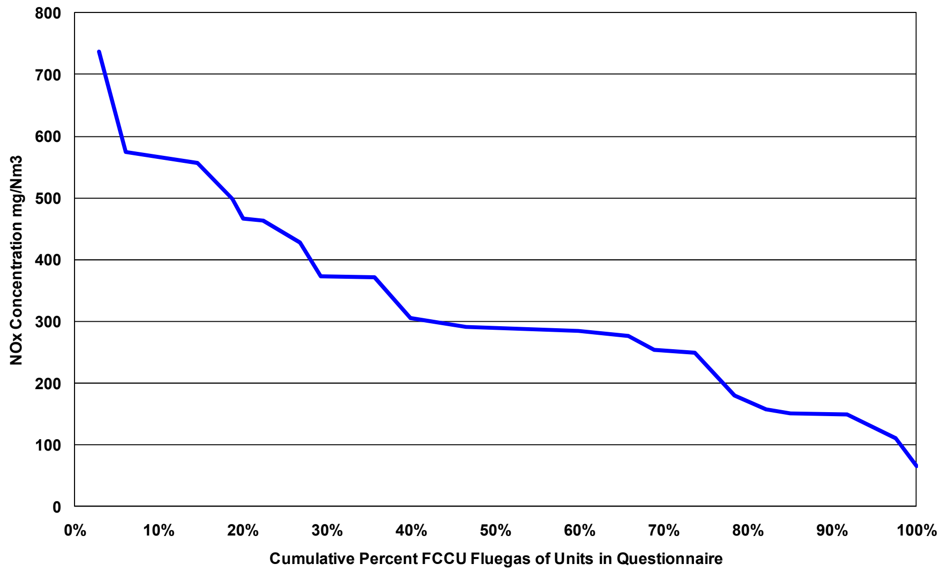
Results for different unit sizes are shown in **Figure 11** with the capital cost to the left vertical axis and the annualised cost to the right vertical axis. The substantial difference in techniques is apparent.

Figure 11 Capital cost and annualised cost for SNCR and for SCR applied to a FCCU of size 2 Mt/year fresh feed



To calculate the marginal abatement cost we need information on the exit NOx emissions from FCCU in order to calculate the amount of NOx removed by SNCR/SCR. As indicated at the outset, CONCAWE detailed data on FCCU is derived from [3] which does not include details on baseline NOx concentrations. To overcome this shortfall, the detailed information provided by European refiners to the EIPPCB for the refinery BREF revision was used [9]. The variation of baseline NOx concentrations versus percent of cumulative flue gas from the plants included in the questionnaire is shown in **Figure 12**. Based on these data we selected a range of 200 to 750 mg NOx/Nm^3 to represent exit concentrations. The lower end of this range likely reflects the use of additives to promote NOx removal in some of the units and so we will use a range of 400 – 750 mg/Nm^3 to represent unabated emissions in the cost-effectiveness study.

Figure 12 FCCU NOx emissions reported in 2009 to the EIPPCB for the revision of the refinery BREF



With these data, marginal costs for the sequential steps – the application of SNCR then the application of SCR over the application of SNCR – are shown in **Figure 13** for the case where the unabated FCC outlet concentration is 750 mg/Nm^3 and in **Figure 14** for the case where the unabated outlet concentration is 400 mg/Nm^3. The higher the outlet concentration the greater the cost-effectiveness (smaller the marginal cost) of the measure.

As mentioned above, the technique SNCR is not applicable to full-burn units (except those having an auxiliary boiler) because the outlet temperature of the flue gases may not be in a range where the technique is applicable. In such cases the incremental technology step is inappropriate and SCR would be applied directly. The results for applying SCR only are not shown here but can be calculated simply by reducing the SCR marginal cost values shown in **Figure 13** and **Figure 14** by multiplying by a factor 0.55 in both cases.

Figure 13 Marginal Abatement Costs for FCCU NOx, outlet concentration 750 mg/Nm^3. The effectiveness of the SNCR is assumed to be 45% and the unabated NOx concentration to be 750 mg/Nm^3

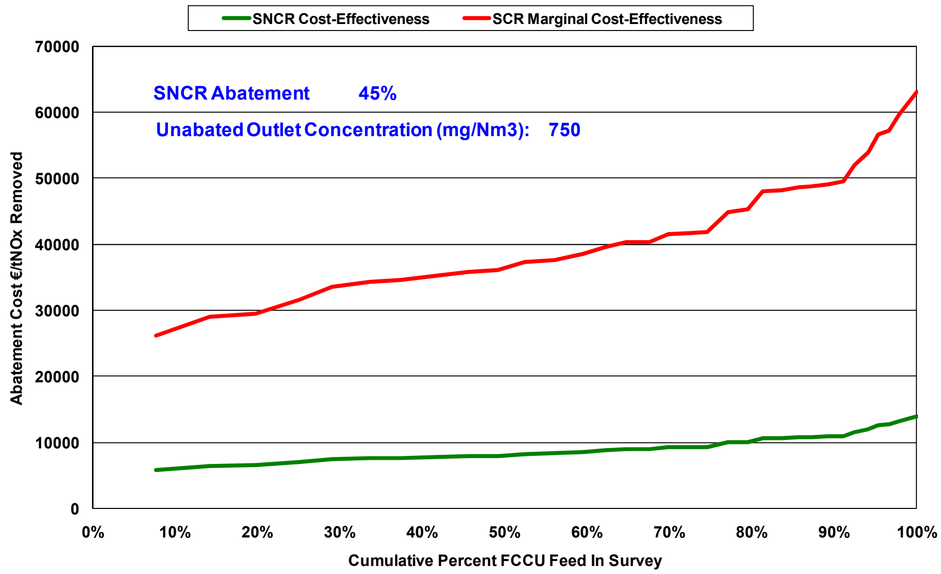
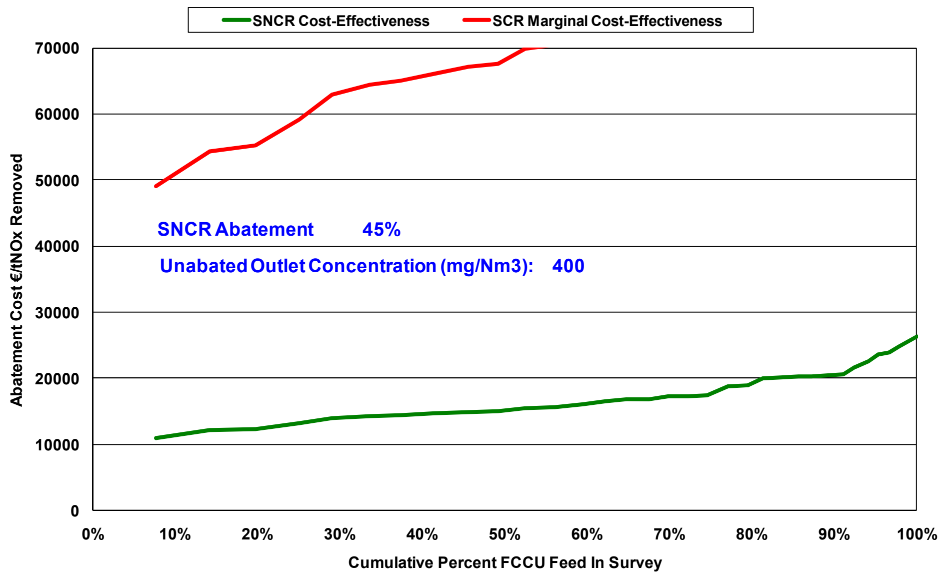


Figure 14 Marginal Abatement Costs for FCCU NOx, outlet concentration 400 mg/Nm^3



4. COST OF INCREASING SULPHUR RECOVERY EFFICIENCY

The sulphur recovery unit (SRU) is a key unit in the refinery and one that can represent a large proportion of the sulphur emission. It is assumed that every refinery has a SRU comprising at least a Claus unit. There are three possible upgrade steps to a basic Claus unit representing different types of tail-gas clean up. The most widely installed is the SuperClaus unit. This is an attractive option because it is available as an upgrade retrofit to a third bed of an existing Claus unit. The next class of technology are the acid dew point type processes. We will use a Sulfreen process as an example but we have not distinguished between different vendor technologies and no significance attaches to our choice. The third class of tail gas unit is the SCOT process which uses a different, amine based, technology.

The annual recovery efficiency for the three tail gas treatment technologies have been taken as 99% sulphur removal for the SuperClaus, 99.5% sulphur removal for the acid dew point process (Sulfreen) and 99.9% for the SCOT plant. These are based on data from [3].

The common assumptions used are

- A reference unit size of 33.3 kt S/a.
- The annualised capital charge is 7.4% (equivalent to 4% interest over a 20 year write-off period).
- The reference fixed operating cost is assumed to be 4%/year of the capital cost.
- The scaling rule for cost of a unit sized F compared to the reference unit is given by: $\frac{Cost\ of\ unit\ [F]}{Cost\ of\ Reference\ Unit} = \left(\frac{F}{F_{ref}}\right)^{0.6}$

The data collection showed that the costs of the reference sized installation were highly site specific.

- The capital costs for the 33.3 kt S/a unit are assessed as lying in the ranges: 6-14 M€ for the SuperClaus; 15-30 M€ for the Sulfreen unit and 30-50 M€ for the SCOT unit. These represent a typical uplift by a factor 3-5 relative to the base EGTEI ranges and again reflect a retrofit installation rather than equipment cost.
- The companies confirmed that the EGTEI variable operating cost data of 3.86 €/t S for the SuperClaus; 2.83-8 €/t S for the Sulfreen and 5.11 €/t S SCOT were realistic.

With this information the capital costs for the three tail gas clean up technologies are shown in **Figure 15** as a function of unit size. Again a mid-range value is used as the basis for the scaling. The annualised costs are shown in **Figure 16**.

Figure 15 Capital cost of different tail gas clean up technologies as a function of unit size scaled from the mid-range cost for each technology

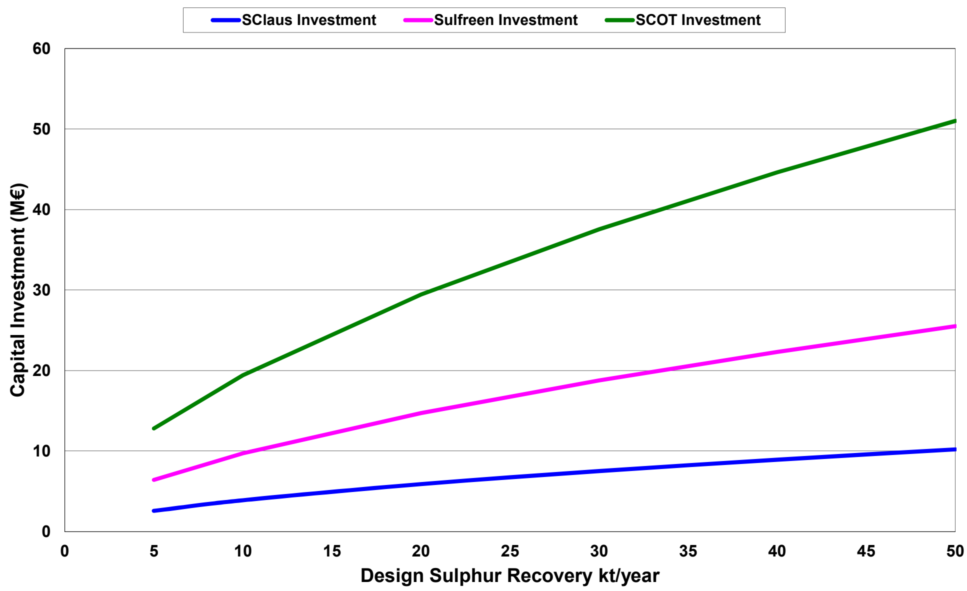
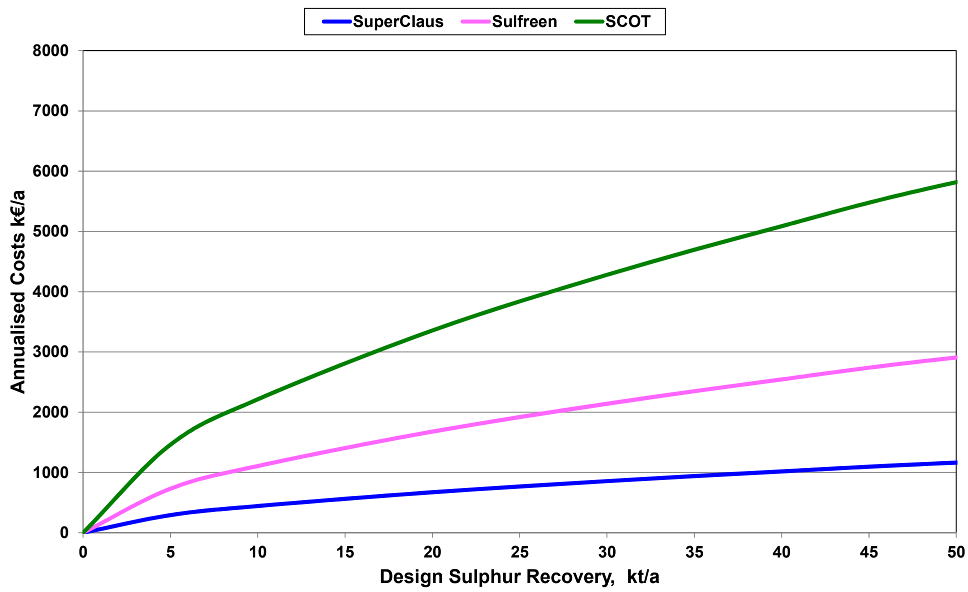


Figure 16 Annualised cost of different tail gas clean up technologies as a function of unit size



To illustrate the spread of values within the range, example costs from the 9 refinery projects in the cost database are shown in **Figure 17**. Four sites installing respectively a SuperClaus unit, two instances of an acid gas clean up unit and one of a SCOT unit all reported similar total project costs (after normalisation) of 30 M€. These results are surprising given the clear fundamental difference in cost of the three technologies. The spread indicates significant variation in the complexity and hence cost of the site specific retrofit. It is known that site SC-4 involved the construction of an entire new reactor while the conventional cost advantage of the SuperClaus process is that existing third stage Claus reactors can be upgraded. The site SCOT-1 may enjoy advantages that reduce the complexity and installation cost. The mid-range values for capital cost used in the marginal cost calculations were 8, 20, 40 M€ for the three technologies respectively. SC-4 is a known outlier. With only two data-points for SCOT we take the mid-point rather than the high value even though we suspect that the SCOT-1 site has some unusual advantages.

Figure 17 Distribution of individual units within the capital cost range

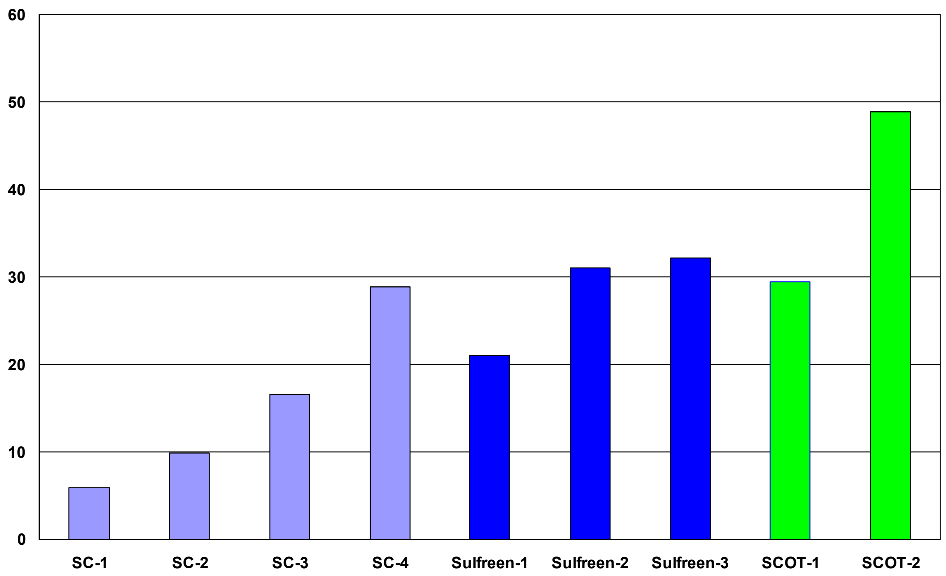
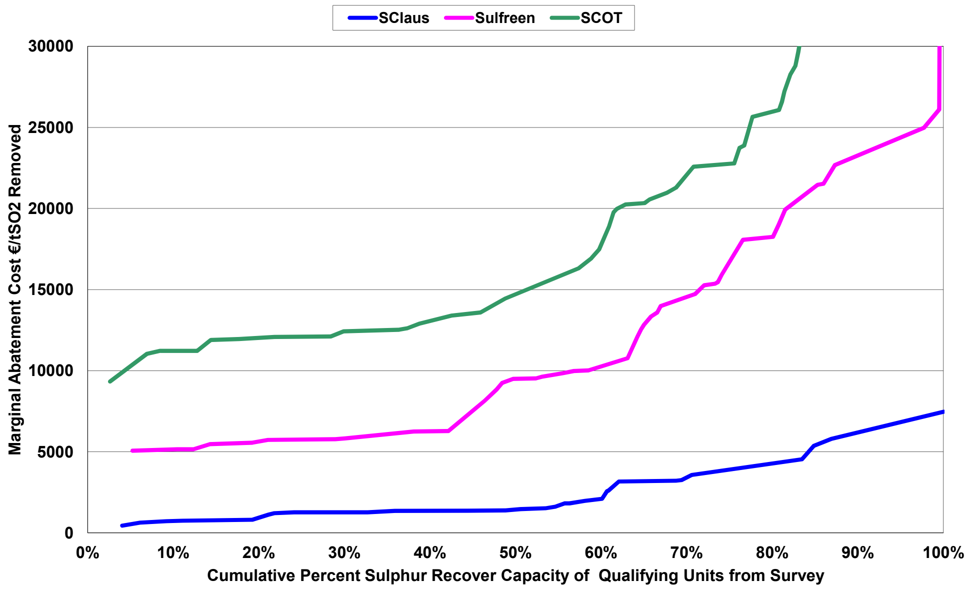


Figure 18 shows the marginal cost of sulphur recovery following the convention of applying the three abatement options in turn. The results are again shown as distributions across the European refineries but some explanation of how these curves are derived needs to be given.

There were 56 sulphur plants represented with sufficient detail in the CONCAWE Sulphur Survey to be used in this analysis. Of these, 20 had a base performance already exceeding the SuperClaus. Of these 20, 8 already had a performance exceeding the Sulfreen and, of these 8, 4 had a performance indicating that a SCOT (or equivalent technology) was already installed.

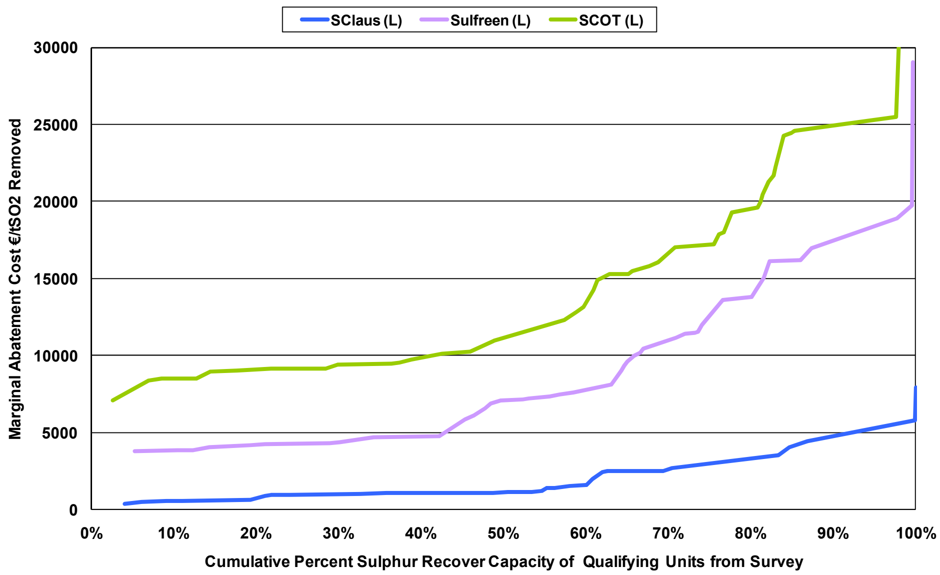
Figure 18 therefore shows on the bottom line the cost-efficiency of raising some 36 plants to the SuperClaus efficiency. The middle line shows the marginal cost of further upgrading those plants to Sulfreen recovery as well as the additional 12 plants already exceeding the SuperClaus standard. The top curve shows the marginal cost of further upgrading all of those plants together with the additional 8 plants having a performance between the Sulfreen and the SCOT.

Figure 18 Marginal cost of applying additional Sulphur abatement using the mid-range annualised costs of **Figure 16**



In view of the spread of costs shown in **Figure 17** the corresponding figure using the lower end of the ranges for capital cost is used as a sensitivity check to derive the marginal costs shown in **Figure 19**. These are not substantially different.

Figure 19 Marginal cost of applying additional Sulphur recovery measures based on the lower limits of the reported capital costs



5. COST EFFECTIVENESS AND BAT

Cost-effectiveness is central to the consideration of what should and what should not be considered a BAT. Article 3(10), paragraph (b), of the Directive on Industrial Emissions [8] states: "'available techniques' means those developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages."

The question then arises - on what basis should cost-effective BAT be assessed?

In this section we explore how, in the refining sector, the distributions of marginal cost corresponding to the theoretical application of different abatement technologies can be combined with an external view of cost-effectiveness in order to demonstrate how BAT AEL ranges can be derived. The Economics and Cross-Media BREF [1] uses the term "shadow price" to express how different mechanisms can be used to assess the cost-effectiveness of measures and we will use this terminology.

For the abatement of emissions such as NOx and SO_2 a good example of a shadow price is obtained through the National Emissions Ceiling Assessment mechanism. The integrated assessment modelling carried out by IIASA[7] explores cost-effective methods of reducing emissions in order to meet environmental improvement targets. The work essentially delivers a multi-dimensional marginal environmental benefit vs. marginal cost curve although, due to the overall complexity, this is usually simplified into a number of discrete scenarios (policy options). A political process involving Member States (in the case of the EU) or parties to the CLRTAP (in the wider European context) then agree the overall ambition by selecting between the policy options.

Such a process was carried out to set the ambition of the Thematic Strategy on Air Pollution (TSAP) to improve the environment as a whole. The Directive on Industrial Emissions was put in place to deliver the EU-wide emission reductions required of industry by the strategy. The EU-wide maximum marginal abatement costs for each pollutant associated with the TSAP targets is therefore a policy consistent choice as the basis for shadow prices.

It should be mentioned that the TSAP was established before both the 2008 economic crisis and agreement on the Climate and Energy Package. Both of these significantly impact the future (projected for 2020) European energy mix and hence basic pattern and quantity of pollutants to be emitted and controls to be applied. However, because the TSAP study reflects a focus on achieving emission reductions through abatement rather than through structural changes it remains a realistic choice.

5.1. METHODOLOGY

The following sections illustrate the application of cost-effectiveness using a graphical representation because this is easy to appreciate. However a rigorous process was applied to the identification of AEL range parameters which is described here.

[7] International Institute for Applied Systems Analysis

The industry data typically comprises a set of emission data expressing annual performance. Ranged against this is a set of emissions that would be achieved at each site if a technology step is applied. Further, there may be second or more sets corresponding to further abatement steps. For each site there is a cost of implementing a step and the emission reduction to be achieved which together give the marginal cost for each step. These steps involve re-applying the size information about each installation so that real emission numbers are in use.

For the first potential abatement step the industry data is sorted in increasing order of marginal cost[8]. The position of the shadow price in the set is then found. Above the shadow price point (higher marginal cost) the abatement step is rejected and the emissions unchanged. Below the shadow price the abatement step is applied and the emissions reduced appropriately. The maximum emission in the whole set is found. This now represents an upper AEL range value[9] consistent with cost-effectiveness of that technology. The minimum emission in the whole set is then found. This represents the lower AEL range value[10] consistent with the cost-effectiveness of that technology.

If more than one technology step is concerned then the above process is repeated. However, where a second technology step is accepted the residual emission is calculated by applying the second step to the original emission. This is because, if shown to be cost-effective, only the most effective step would, in practice, be applied from that starting point.

It is important to note that the values presented here are illustrative of the overall process. Generic annual averaged emissions are used as the starting point and, unless otherwise stated mid-range costs. The methodological derivation of AEL ranges based on this demonstration is not intended as proposed values for permit use. A case study is needed for each installation.

[8] This ranking of the accompanying emissions is different because of the effects of scale on emissions and costs are not the same.

[9] Upper range value if emissions are used, lower range value if abatement efficiencies are used, e.g. % SRU recovery.

[10] Lower range value if emissions are used. If abatement efficiencies are used this will be the actual value of the measure as, once the measure is applied it is assumed this will be achieved.

5.2. CASE OF THE SRU

Figure 20 Comparison of Marginal Cost Curves with the European Shadow Price

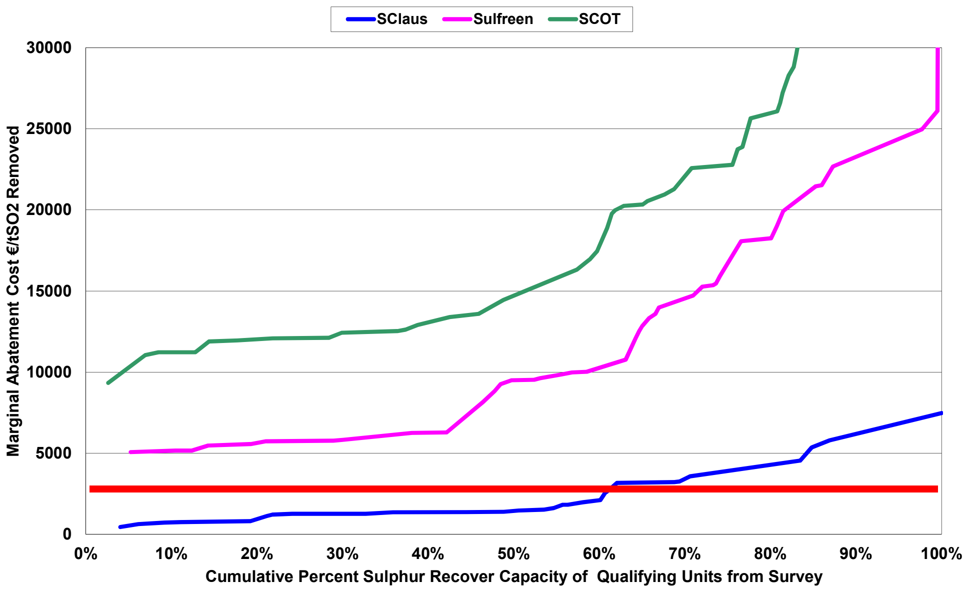


Figure 20 illustrates the marginal cost performance of applying three different incremental technology steps overlaid by the shadow price for Sulphur Dioxide (SO_2).

- The lower line represents the marginal cost of moving to a 99% recovery for those refineries recovering less.
- The middle line is the marginal cost of then moving to 99.5% recovery (or to 99.5% recovery for those refineries having a recovery between 99 and 99.5%).
- The top line is the marginal cost of moving to a recovery of 99.9%. The cost steps are different for the various refineries because they all have a different starting point and are of different size (costs being a function of size).

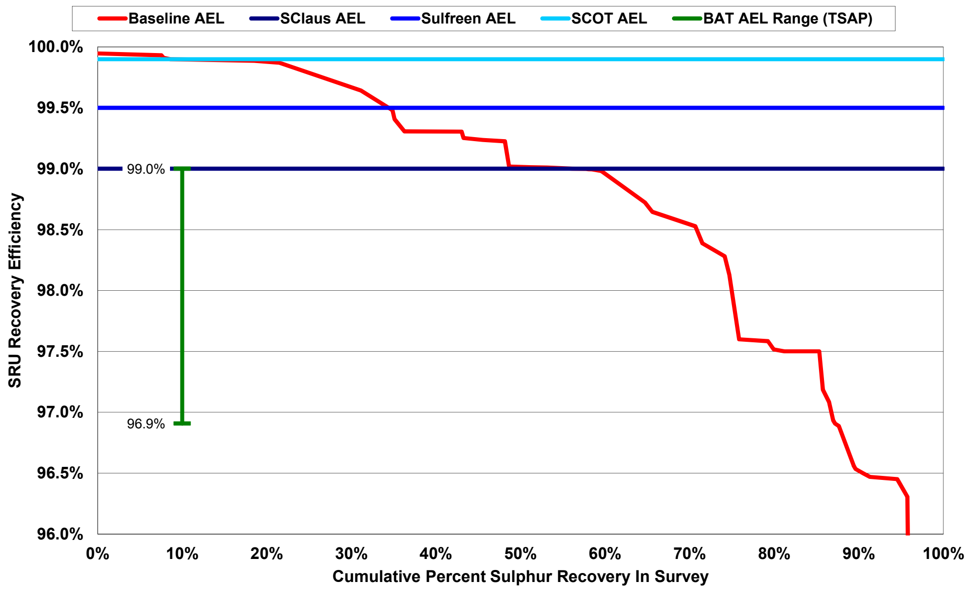
The shadow price overlay intersects the lower curve at a horizontal position of about 60%. This indicates that it would be cost-effective to upgrade some 60% of the European sulphur recovery capacity that operates at less than 99% efficiency. Equally, the remaining 40% have a case to argue that an improvement measure would not be cost-effective.

The marginal cost line falls everywhere below the middle curve indicating that a further step towards a Sulfreen type process or a SCOT plant would not be justified.

Importantly we can note that the intersection of the shadow price and the marginal cost curve marks a refinery operating at about 96.9% recovery efficiency. As the refineries are essentially ranked in order of increasing efficiency this value can be taken as a lower boundary for cost-effective BAT performance and hence (in the parlance of the BREF) provides a means of placing a value on the upper BAT AEL range.

Figure 21 shows these results cast into a form that informs on the consequence of such a BAT AEL range definition. The vertical line shows the indicated AEL range. This goes from 99% (the lower end of the range determined by the technology selection) and 96.9% which was the cost-effectiveness break point. The descending line shows the current profile of performance across the industry. The horizontal lines mark the 3 technology steps considered.

Figure 21 Illustration of BAT AEL range for Sulphur recovery based upon Shadow Price



The implications of setting a value of 96.9% recovery as an upper AEL range are illustrated below. **Figure 22** shows the number of SRU plants in the survey and their current recovery efficiencies. There are currently 35 plants having an efficiency less than 99% or below the lower AEL range. **Figure 23** shows that an upper AEL range of 96.9% would require some 21 plants to invest to improve recovery. The improvement would at minimum be expected to achieve the lower AEL range for that technology.

Figure 22 Current status of refinery sulphur recovery

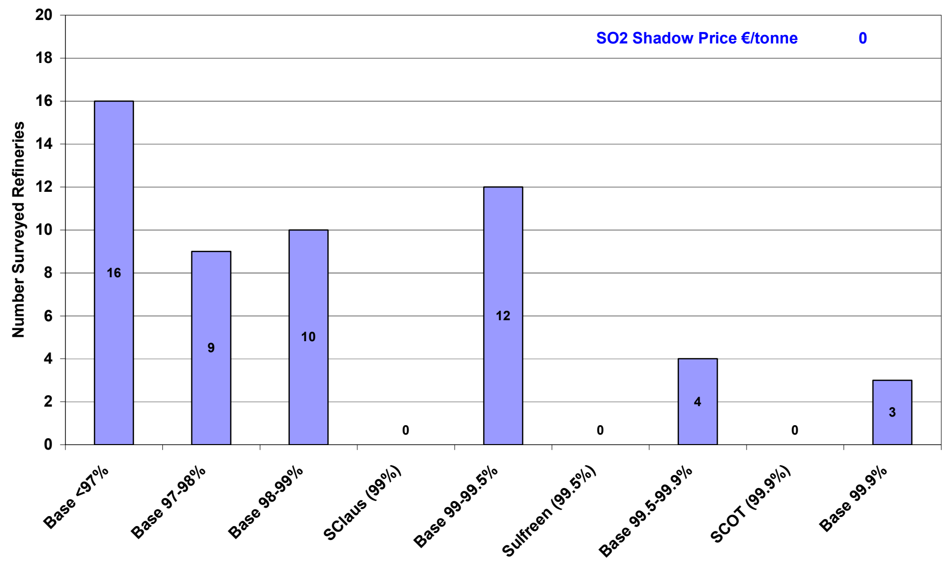
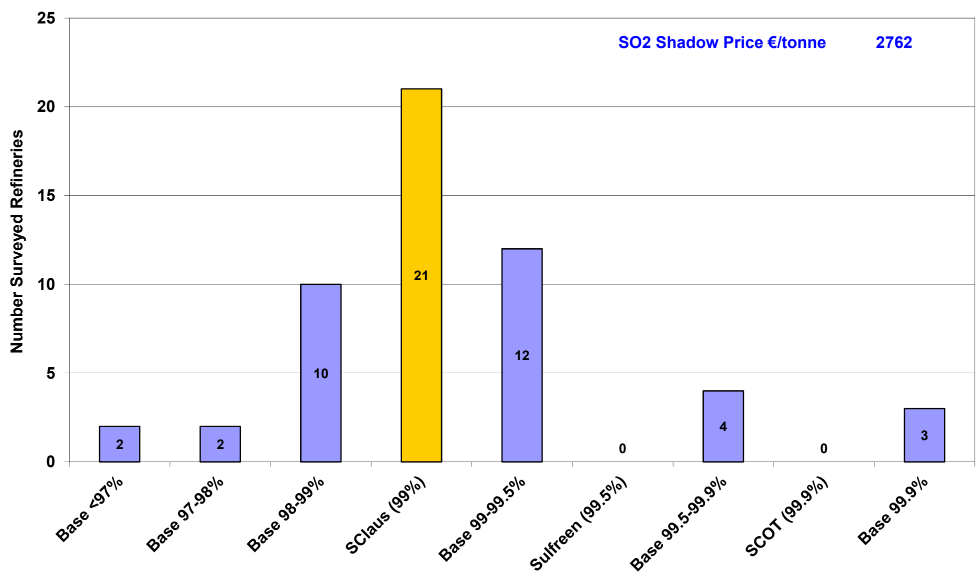
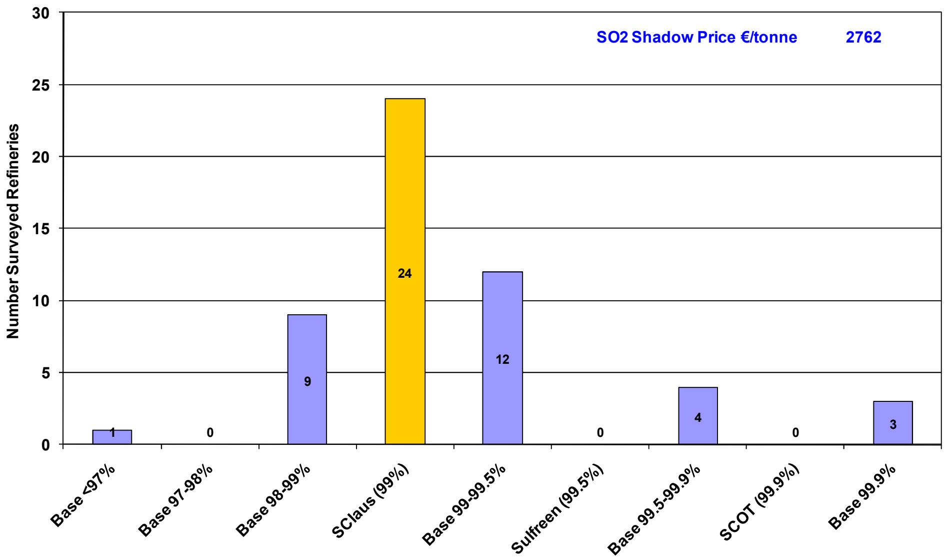


Figure 23 Effect on investment of setting the upper AEL range based on shadow price



In view of the range of cost information this calculation has been repeated for a lower cost (and hence marginal cost) of the abatement technologies. The results are very similar and are shown in **Figure 24**. The number of sites upgrading becomes 24 but there is no implied technology change.

Figure 24 Implications of setting an upper AEL range based on the shadow price at using low end rather than middle of range costs for the abatement technologies



5.3. CASE OF THE FCCU - SO_2 EMISSION REDUCTION

Two technologies were considered for the control of SO_2 emissions from catalytic cracking plant: SRA and WGS. Two levels of activity for SRAs were assumed according to the operating mode of the cracking unit.

Figure 25 and **Figure 26** show the effect of overlaying the shadow price on the marginal cost curves for these two technologies. On this basis the application of SRA would widely be considered to be cost-effective for the FCCU capacity in the survey, remembering that in practice each installation would have to make that assessment. We have not considered, for example, feed desulphurisation as a mitigation option and some sites may use this to control the FCCU yield composition.

For high SRA effectiveness, WGS would be cost effective for some 35%, not cost-effective for some 45% of capacity and marginal for some 20% of capacity. For low SRA effectiveness then WGS becomes more cost-effective and would be justified for nearly 60% of the units in the survey and marginal for a further 20%.

Figure 25 Marginal Cost Curves for FCCU SO_2 abatement overlaid with shadow price – high additive efficiency applied to full burn units

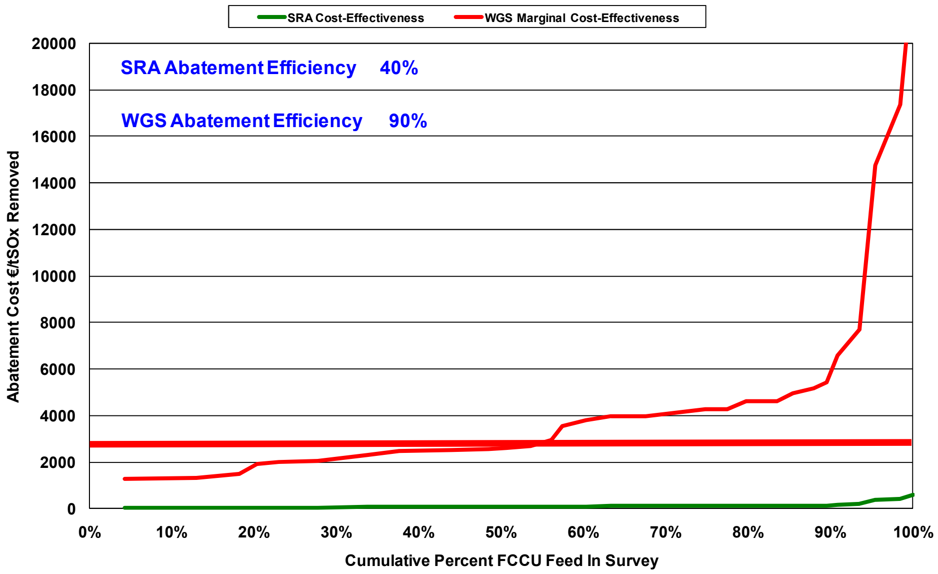
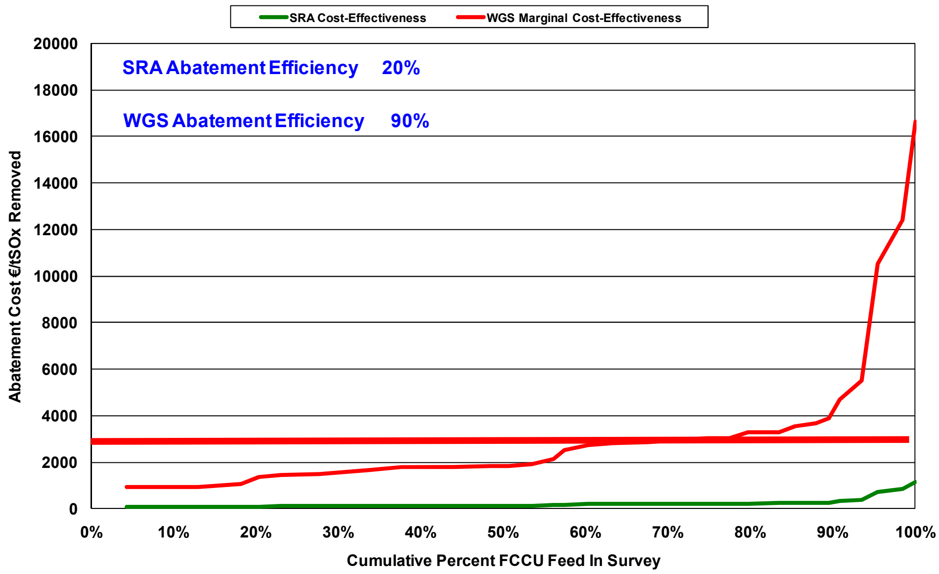


Figure 26 Marginal Cost Curves for FCCU SO_2 abatement overlaid with shadow price – low additive efficiency applied to partial burn units



In the same way as for the SRU, the intersection of the shadow price with the marginal cost curve identifies an emission value that can be interpreted as an estimated upper end AEL value. Again the lower AEL value is determined by the technology application. The results are shown in **Table 2**.

Table 2 BAT AEL Ranges for WGS derived from cost-effectiveness examples

Application	UPPER mg/Nm^3	LOWER mg/Nm^3
Full Burn (40% SRA eff.)	2037	185
Partial Burn (20% SRA eff.)	1383	185

To illustrate the impact of setting such AEL bounds on the sample set we estimate the number of units that would have to take measures based upon our sample. Firstly, **Figure 27** shows the current distribution of performance across the surveyed units (top line labelled baseline AEL), then the curves with the emission reduced by 20% and 40% respectively corresponding to SRA use in partial burn and full burn units. At the bottom is a curve corresponding to the 90% reduction achieved with WGS. The vertical lines indicate the range of AEL values between the lower BAT range (WGS) and the value at which the shadow price and marginal cost curve intercept in **Figure 26**. By reading across the graph it is possible to see the proportion of units falling within the AEL ranges while applying SRA technology and those only lying inside the AEL ranges if applying WGS.

Figure 27 Illustration of BAT AEL ranges for FCCU SO_2 control based upon shadow price

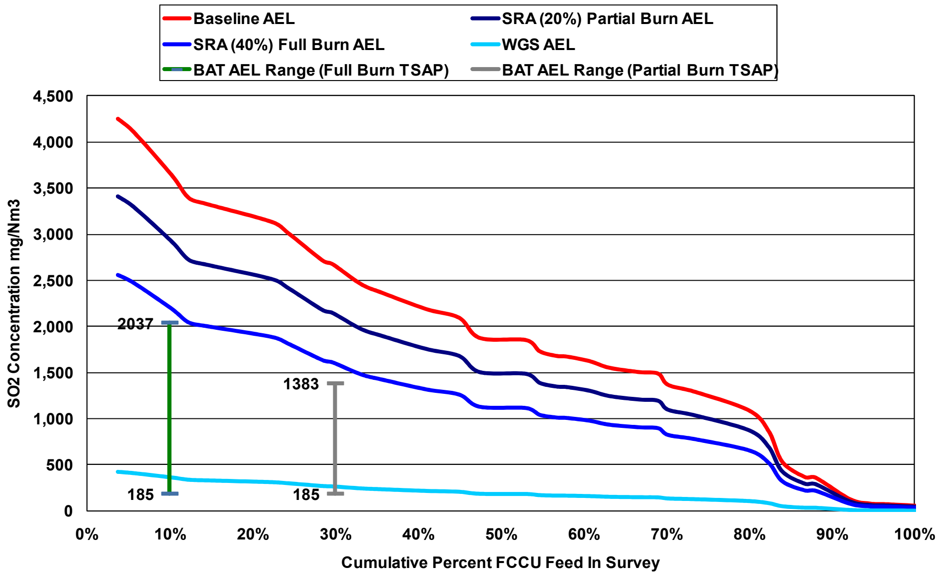


Figure 28 shows the distribution of FCCUs in the survey having baseline emissions in several ranges both outside and inside the indicated BAT AEL ranges. The two bars to the left indicate that 13 units have base-line emissions above 2000 mg/Nm^3 i.e. above the upper AEL range indicated by the shadow price. If the technology SRA, achieves an emission reduction of 40% then the marginal cost was lower than the shadow price for all of the cases considered under model assumptions[11]. Taking WGS as the next step, then the marginal cost is less than the shadow price in 12 cases. The results are shown in **Figure 29** and suggest that in seeking to reduce emissions all sites in the survey might consider at least applying SRA and a third to apply WGS If the technology SRA is less effective in reducing emissions (i.e. 20% typical of partial burn units) then the marginal cost of SRA increases and the incremental marginal cost to WGS becomes smaller. The cost-effectiveness assessment then suggests that the 3 sites having low basic emissions might find the SRA application not cost-effective but for an overall larger number of sites (almost half) the WGS option becomes more attractive.

We noted above that these technology choices were not exclusive. The feed to a FCCU may be pre-processed to influence the product split and this pre-treatment (feed hydro-treating) can reduce the sulphur content and hence emissions. Emissions abatement is, however, not the main purpose of feed treatment and we have not considered it an abatement technique in this report. Some operators have also reported higher than 40% removal efficiency for SRA application.

[11] As noted previously, this is a general statement based on our assumptions about the underlying data. In practice, individual site situations would need to be evaluated.

Figure 28 Distribution of base-case FCCU SO_2 emissions with units grouped into emission bands

Figure 29 Implications for FCCU SO_2 control of applying BAT AEL ranges based on cost-effectiveness for measure SRA at 40% efficiency

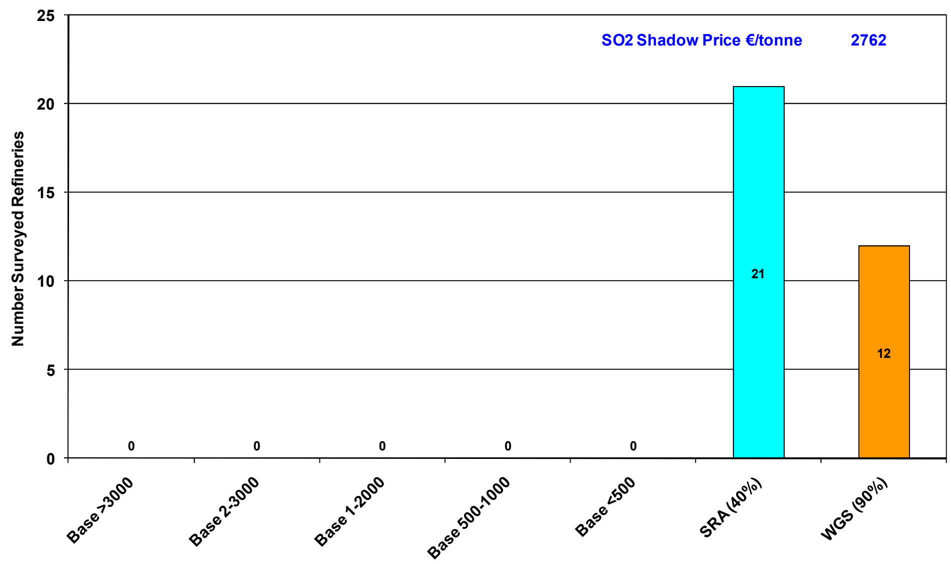
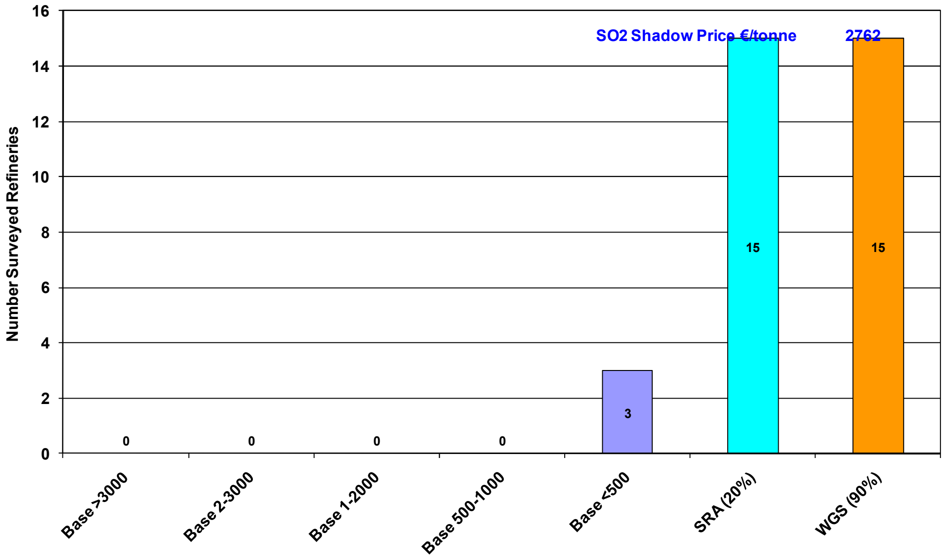


Figure 30 Implications for FCCU SO_2 control of applying BAT AEL ranges based on cost-effectiveness for measure SRA at 20% efficiency



5.4. CASE OF THE FCCU - NO_X EMISSION REDUCTION

The results of overlaying the policy shadow price of 1053 €/tonne on the marginal cost curve for NOx abatement is shown in **Figure 31** and **Figure 32**. As discussed previously, the marginal cost depends on the unabated NOx emission and we have taken two values, 750 and 400 mg/Nm^3, to delimit the unabated range indicated by the EIPPCB for the refinery BREF revision.

Two technologies were considered: SNCR having a reduction efficiency of 45% and SCR having a reduction efficiency of 85%. Thus, in following the methodology of GAINS we assume, for assessing cost-effectiveness[12] and evaluating incremental marginal cost, the technology steps would reduce emissions from 750 mg/Nm^3 to 412 mg/Nm^3 applying SNCR and then to 62 mg/Nm^3 by applying SCR in the first case and from 400 mg/Nm^3 to 220 mg/Nm^3 to 33 mg/Nm^3 in the second case.

We note that, due to the operating temperature range of SNCR it is only applicable to partial burn units or those full burn units using an additional auxiliary-fired boiler. To account for this we also include results obtained assuming that SCR is the only available technology. In this case the exit concentrations would be 112 mg/Nm^3 and 60 mg/Nm^3 for the two starting points.

Figure 31 shows that the shadow price does not intersect the curve for emissions reductions by SNCR and the minimum marginal cost is about ten times greater. Thus none of the FCC units considered would find this technique cost-effective. It follows then that additional incremental marginal cost of moving to SCR is massively higher than the shadow price. Further, taking the lower unabated emission, as in **Figure 32**, increases the marginal cost. **Figure 33** and **Figure 34** show the same conclusion with respect to the application of SCR only.

[12] To recall the methodology: Incremental marginal costs are applied to technologies in series to test whether each potential incremental improvement is cost justified. The residual emission is the unmitigated emission reduced by the "highest" technique that proves overall cost effective. i.e. only the one technique would be applied in practice. The earlier example of the WGS and the SRA was that, if a site found WGS cost-effective then it would not use. If a site making a decision between installing SCR or SNCR found SCR to be cost-effective then (unless there were other technical considerations) it would not consider to install SNCR

Figure 31 Marginal Cost Curves for FCCU NOx abatement overlaid with policy shadow price – initial NOx concentration high

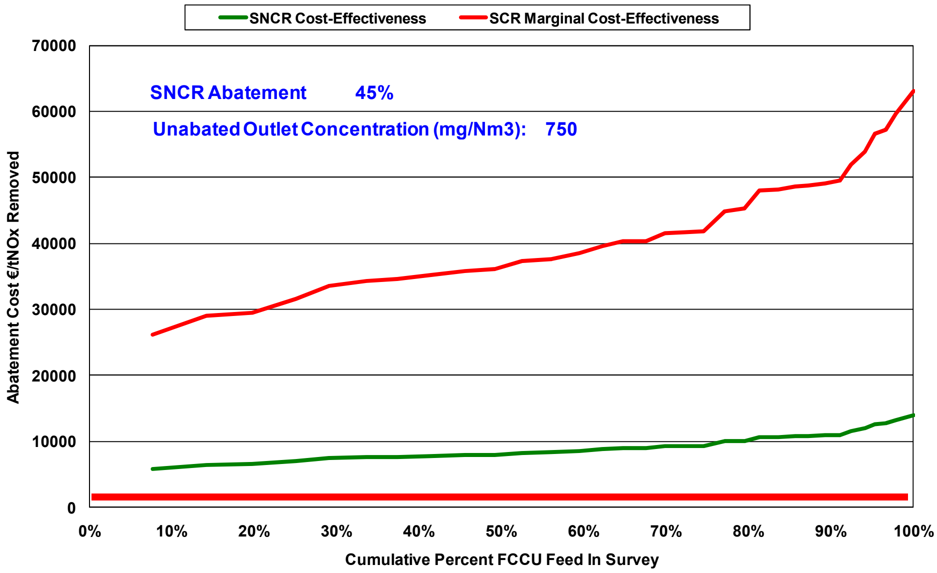


Figure 32 Marginal Cost Curves for FCCU NOx abatement overlaid with policy shadow price – initial NOx concentration low

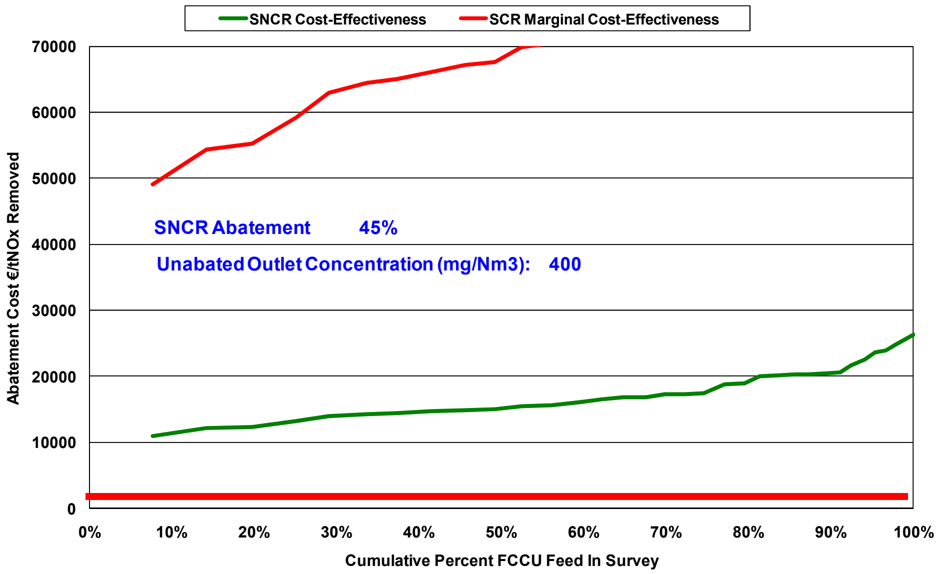


Figure 33 Marginal Cost Curves for FCCU NOx abatement, only SCR applicable, overlaid with policy shadow price – initial NOx concentration high

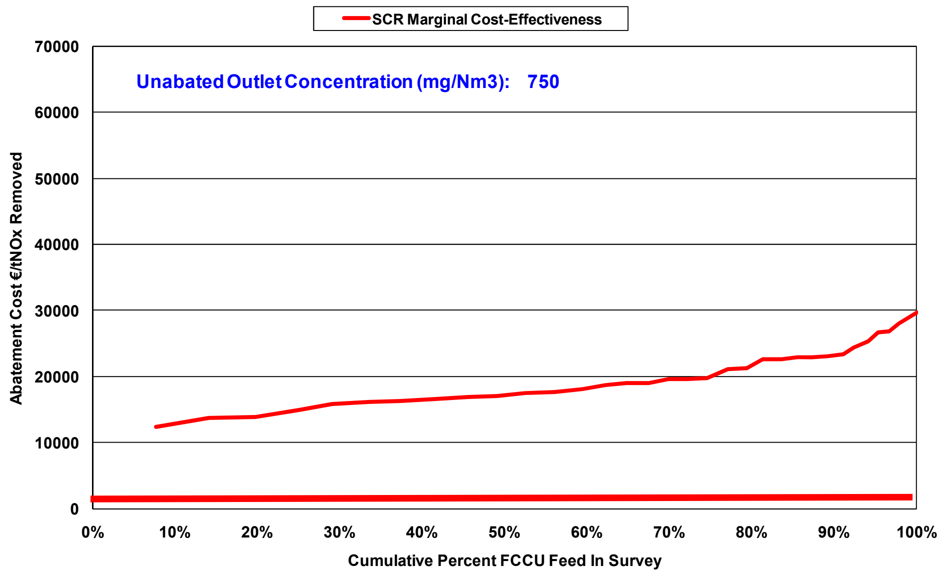
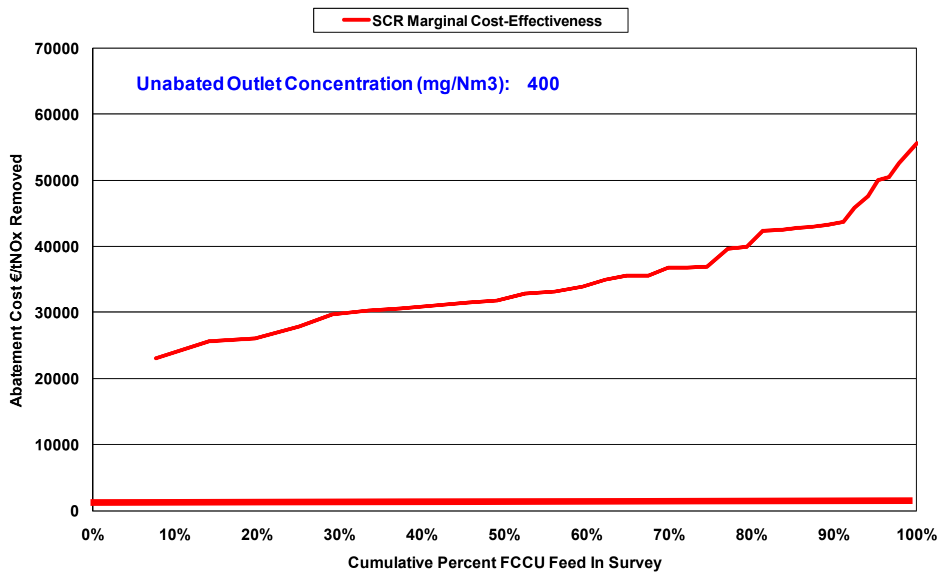


Figure 34 Marginal Cost Curves for FCCU NOx abatement, only SCR applicable, overlaid with policy shadow price – initial NOx concentration low



5.5. CASE OF THE COMBUSTION SYSTEM – SO_2

In the last examples we look at the consequences for the combustion system. As before the policy shadow price is overlaid on the marginal cost curves in **Figure 35**. The two technologies considered are WGS and substitution of fuel oil by natural gas. The marginal cost of gas substitution is very dependent on the gas price differential over fuel oil (internal stream). This price differential has been taken to be 100 €/t of FOE but is very uncertain in the future. Availability of gas has not been considered. As these options are mutually incompatible the cost curves are not incremental and the technologies can be considered "competitive".

The overlay of the policy shadow price of 2672 € is shown in **Figure 35**. The option for WGS appears competitive for about 30% of the refineries in the survey. The fuel-oil to gas price differential would have to be about half of the test value of 100 €/t_{FOE} to have the same impact.

Figure 36 shows the BAT AEL range that might be derived from this cost-effectiveness approach and knowledge of the installed technology base. The intercept in **Figure 35** corresponds to an emission concentration of just over 1000 mg/Nm^3 giving (at 85% removal efficiency) an abated emission of some 160 mg/Nm^3. In view of the Large Combustion Plant Directive (LCPD) bubble value of 1000 mg/Nm^3 the upper AEL range suggested by the cost-effectiveness based on shadow price could be rounded down to this value.

Combustion emissions should properly be described as an overall component of the refinery bubble and we have not attempted to break out the potential number of stacks that could require WGS to be installed. In view of the investments required these are likely to be the largest stacks and the benefit here is expressed as a reduction in the combustion bubble.

Figure 35 Marginal Cost Curves for SO_2 abatement in the Combustion system overlaid with base case shadow price

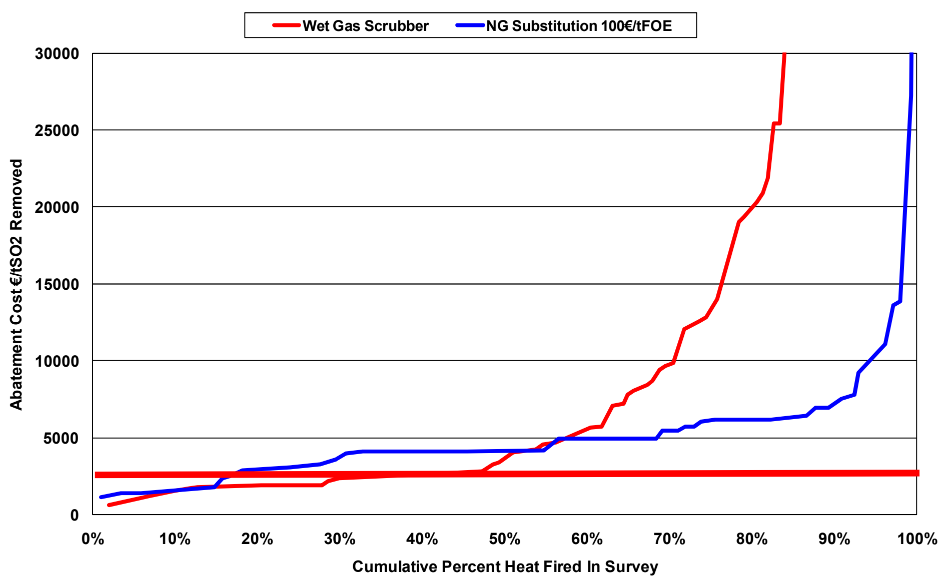
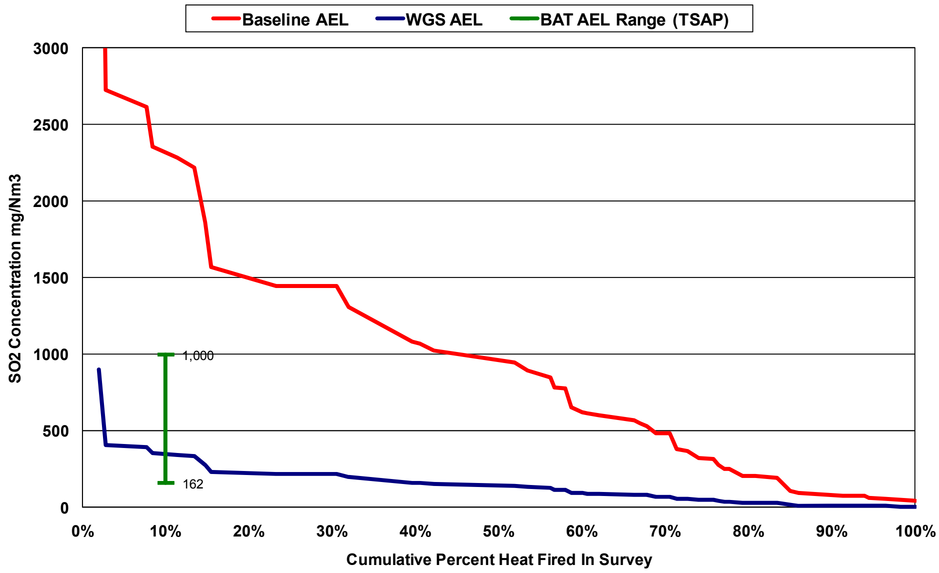


Figure 36 Illustration of BAT AEL ranges for SO_2 control from combustion using cost-effectiveness arguments



5.6. CASE OF THE COMBUSTION SYSTEM – NO_X

The case of combustion system NOx removal is now addressed. It is assumed that all combustion units are (or could be) fitted with low NOx burners. A number of factors can affect low NOx burner performance [3] and are not accounted for here.

The technology steps SNCR and SCR are considered sequential options for assessing cost-effectiveness following the GAINS methodology. However, because SNCR is not always applicable the single technology step SCR has also been considered.

Results are shown in **Figure 37** and **Figure 38** for the two step technology assuming the two levels of SNCR efficiency and in **Figure 39** for SCR only.

In all cases the application of SNCR and SCR is not cost-effective at this value of the shadow price. It is therefore not possible to derive clear guidance on the upper AEL bound from cost-effectiveness arguments other than to say that this would depend on the performance of low NOx burners for which a range of 450 – 200 mg/Nm^3 corresponding to a range of fuel mixture from liquid to gas respectively, is appropriate. This is illustrated in **Figure 40**.

Figure 37 Marginal Cost Curves for NOx abatement in the Combustion system overlaid with policy shadow price and assuming 50% efficiency for SNCR

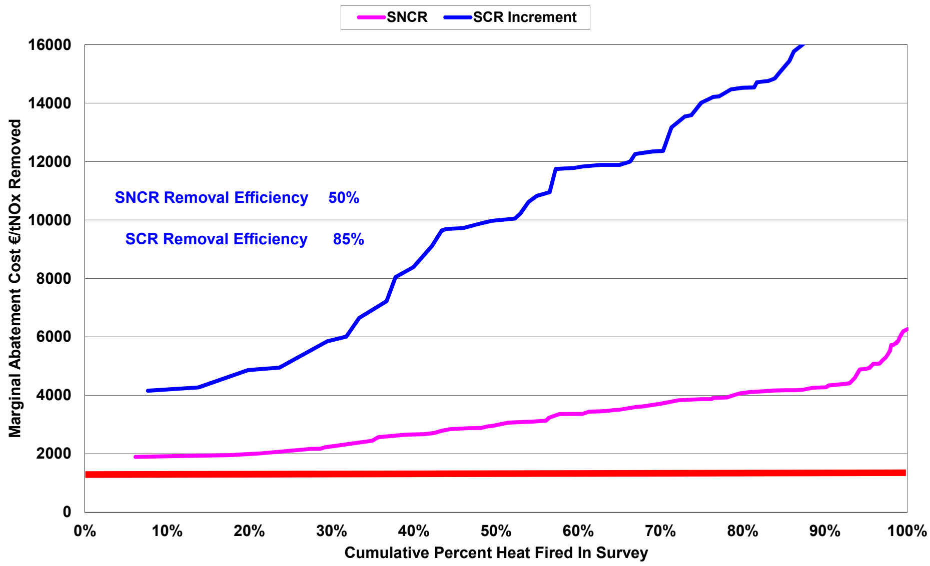


Figure 38 Marginal Cost Curves for NOx abatement in the Combustion system overlaid with policy shadow price and assuming 30% efficiency for SNCR

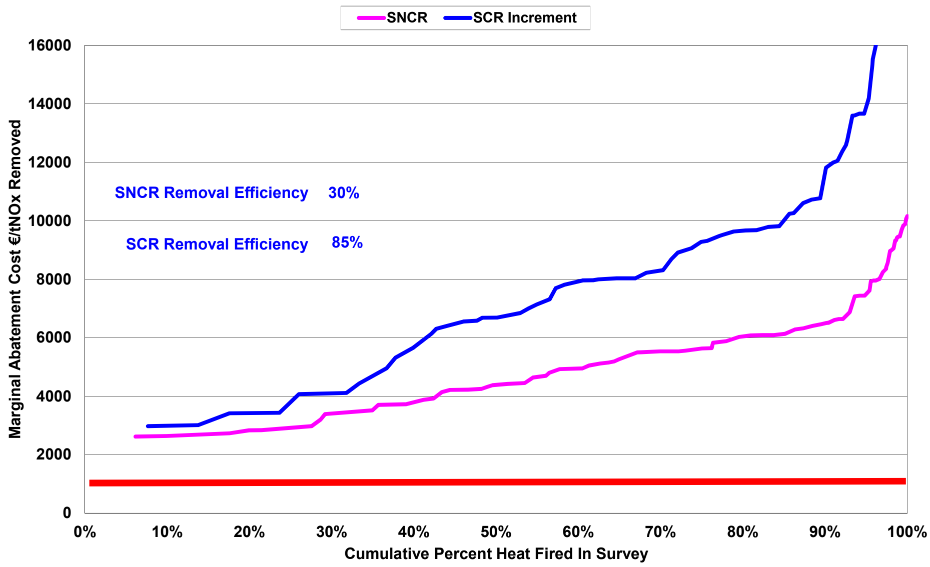


Figure 39 Marginal Cost Curves for NOx abatement in the Combustion system overlaid with policy shadow price and assuming only SCR is applicable

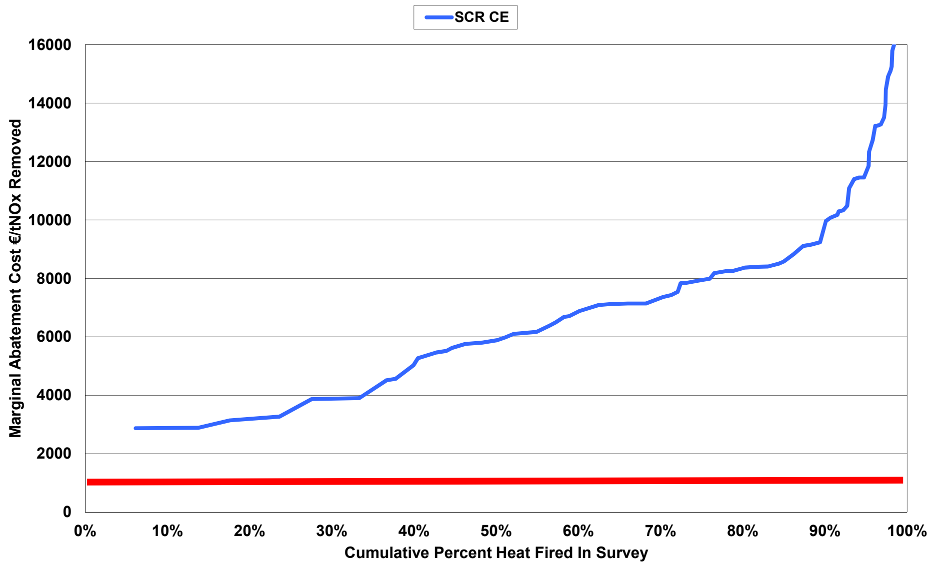
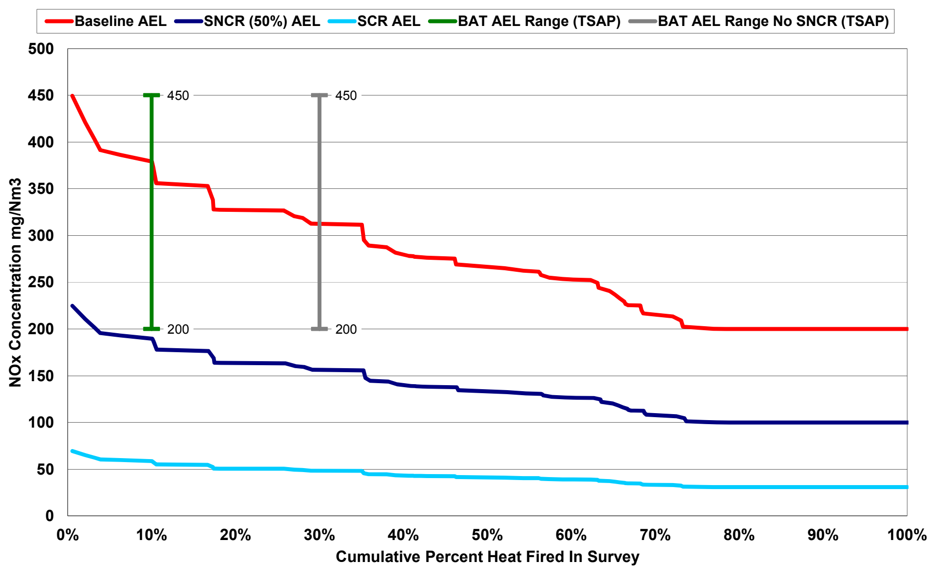


Figure 40 Distribution of emissions baseline and reduced by SNCR and by SCR application together with the cost-effective AEL ranges



6. CONCLUSIONS

Data on abatement costs for refinery NOx and SO_2 have been gathered for the combustion system and those process units having significant emissions. The results were based on the EGTEI 2005 sector studies and updated with emphasis on capturing retrofit costs. For established sites the retrofit costs can be a very major component of a project cost. For this reason the capital costs were significantly greater than those documented by EGTEI. However, the variable operating costs of the abatement possibilities were quite comparable to the EGTEI data.

Costs have been expressed as capital costs, annualised costs and marginal abatement costs (€/tonne abated). The annualised costs presented here used a policy basis (4% interest, 20 year repayment) and are therefore lower than would be assessed using typical sector business methods.

CONCAWE, through its Sulphur Survey [3], is able to assess the distribution of emissions from different units across Europe. With this information the relative cost-effectiveness of measures can be assessed and the distribution of marginal cost for adopting a technology measure across the sector assessed.

Integrated Assessment Modelling is the accepted means of determining the cost-effective emission reductions in Europe at a national scale (National Emissions Ceilings) needed to achieve environmental improvement targets under CLRTAP. The same methodology was used by the EC in determining the ceilings in the current NEC Directive [10] and for the work done to develop the TSAP. The methodology uses marginal cost information, expressed in incremental technology steps, in its optimisation process.

The EU wide costs of abating SO_2 and NOx that result from the TSAP have been used to set a policy shadow price (€/t) for each pollutant. The values used are 2762 €/t for SO_2 and 1053 €/t for NOx. As set out in the Economics and Cross Media BREF, comparison of the marginal cost of an abatement step with an appropriate "shadow price" is an essential step in assessing cost-effectiveness of a measure.

By utilising the policy shadow price and the distribution of marginal costs across the sector it is possible to separate cost-effective from non-cost-effective measures. This divide occurs at a particular level of environmental performance which can be calculated. This offers a means of relating cost-effectiveness and associated emission levels for the sector. This is extremely important to the development of conclusions on BAT and BAT AEL ranges which should be met in a cost-effective manner.

The following results were found and compare well with the data based proposals for BAT AEL ranges made in [5] noting that that in the main text we distinguish between installation specific ranges in the performance based data and generic ranges from the cost-effectiveness argument and bounds were not found for each case using the assumptions and techniques considered here.

Table 1 Comparison of performance based AEL range values proposed in CONCAWE Report 4/09 [5] and illustrative values derived from a cost-effectiveness assessment

	Operational data			Cost-Effectiveness		Comment
Application	lower	upper	units	lower[13]	upper[14]	
Combustion NOx - Gas	50	200	mg/Nm^3		450	No cost effective AEL range based on an initial concentration of 450 mg/Nm^3 was able to be derived from application of SNCR or SCR
Combustion NOx - dual fired (liquid > 50%, N < 0.5%)	300	450	mg/Nm^3			
Combustion SO_2	none proposed		mg/Nm^3	162	1000	Application of WGS or Fuel Substitution by Natural Gas applied to combustion bubble.
FCCU NOx - full burn	300	700	mg/Nm^3		750	No cost effective AEL range identified by this study based on an initial concentration of 750 mg/Nm^3 with respect to application of SNCR or SCR.
FCCU NOx - full burn - residue with Antimony injection	300	1000	mg/Nm^3			
FCCU NOx - partial burn	100	800	mg/Nm^3			
FCCU SO_2 - full burn	none proposed		mg/Nm^3	185	2037	WGS application and SRA @ 40%
FCCU SO_2 - partial burn			mg/Nm^3	185	1383	WGS application and SRA @ 20%
SRU efficiency	99.9	98	%S recovered	99	96.9	For units having recovery < 99%

[13] Lower values of the range reflect assumptions on effectiveness and starting concentrations

[14] Upper values of the range may indicate unabated generic emissions in the event that the cost-effectiveness argument did not identify a limit lower than the initial assumptions.

7. GLOSSARY

AEL	Associated Emission Level
BAT	Best Available Techniques
BREF	BAT Reference Document
CLRTAP	Convention on the Long Range Transport of Air Pollution
EGTEI	Expert Group on Techno-Economic Issues
EIPPCB	European Integrated Pollution Prevention and Control Bureau
FCCU	Fluidised Catalytic Cracking Unit
FOE	Fuel Oil Equivalent (Energy Content 4.186 GJ/t)
IED	Directive on Industrial Emissions
IPPC	Integrated Pollution Prevention and Control
LCPD	Large Combustion Plant Directive
NEC	National Emissions Ceilings
NECD	National Emissions Ceilings Directive
NG	Natural Gas
NOx	Nitrogen Oxides expressed as NO_2
SCOT	Shell Claus Off-gas Treating
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SOx	Sulphur Oxides
SO_2	Sulphur Dioxide
SRA	Sulphur Reducing Additive
SRU	Sulphur Recovery Unit
TSAP	Thematic Strategy on Air Pollution
TWG	Technical Working Group (convened to revise or create a BREF document)
WGS	Wet Gas Scrubbing

8. ACKNOWLEDGEMENTS

This work would not have been possible without the help and assistance of CONCAWE member company support to the Air Quality Special Task Force STF-70:

Lucia Gonzalez Bajos
Sonia Hernandez Barrado
Alexander Buchsbaum
Pawel Chetkowski
Georges De Caluwé
Jesus Angel Nieto Cruz
Patrice Béraud-Dufour
Stefan Ehrenreich
François Leotoing
Garifalia Maheridou
Adelaide Mendes
Réka Söjtöriné Mészáros
Heinz-Dieter Sinnen

9. REFERENCES

1. EIPPCB (2006) Integrated Pollution Prevention and Control (IPPC) - reference document on economics and cross-media effects. Sevilla: European IPPC Bureau http://eippcb.jrc.ec.europa.eu/reference/ecm.html

2. IIASA (2011) GAINS Europe. Laxenburg: International Institute for Applied Systems Analysis
http://gains.iiasa.ac.at/index.php/gains-europe

3. CONCAWE (2010) Sulphur dioxide emissions from oil refineries in Europe (2006). Report No. 1/10. Brussels: CONCAWE

4. EU (2005) Communication from the Commission to the Council and the European Parliament: Thematic strategy on air pollution - COM(2005) 446 final

5. CONCAWE (2009) Refining BREF review – air emissions. Report No. 4/09. Brussels: CONCAWE

6. IIASA (2005) CAFE scenario analysis report nr. 6: a final set of scenarios for the Clean Air For Europe (CAFE) programme. Laxenburg: International Institute for Applied Systems Analysis
http://ec.europa.eu/environment/archives/cafe/activities/pdf/cafe_scenario_report_6.pdf

7. EU (2005) Commission staff working paper: annex to the communication on thematic strategy on air pollution and the Directive on ambient air quality and cleaner air for Europe - SEC(2005)1133
http://ec.europa.eu/environment/air/pdf/sec_2005_1133.pdf

8. EU (2010) Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control). Official Journal of the European Union No. L334, 17.12.2010

9. EIPPCB (2010) Integrated Pollution Prevention and Control (IPPC) – draft reference document on Best Available Techniques for mineral oil and gas refineries. Sevilla: European IPPC Bureau
ftp://ftp.jrc.es/pub/eippcb/doc/ref_d1_0710.pdf

10. EU (2001) Directive 2001/81/EC of the European Parliament and of the Council of 23 October 2001 on national emission ceilings for certain atmospheric pollutants. Official Journal of the European Communities No. L309, 27.11.2001

APPENDIX A USE OF REFINERY FUELS

This Appendix describes the factors affecting a refinery choice to replace internal fuel oil with imported natural gas.

Refineries need energy generated by combustion in order to perform conversion operations that require either direct heat input via furnaces and heaters or indirect heat input from steam produced in boilers. Steam may also be used directly as a feedstock in some cases. Part of the energy released by combustion may also be converted into electricity by means of gas or steam turbines.

Preferentially the refinery uses a small fraction of its throughput (in both liquid and gaseous form) for its energy generation but replacement of liquid fuel by imported natural gas may be considered an option when considering emission reduction for the refinery.

Refineries produce gas by-products from a number of different processes. The composition of these gases can be very variable. Efforts are made to recover valuable components such as C3 and C4 hydrocarbons for use in further upgrading while leaving residual streams of C2, H_2, CO, N_2, CO_2 + lesser amounts of higher hydrocarbons.

The options for recovering pure hydrocarbons from these streams for use as a product are limited, although in some high hydrogen content streams there may be an economic case for recovering the hydrogen for use as a feedstock. When recovery as feedstock is not economical these gaseous residues are used as fuel within all refineries. For overall efficiency and environmental reasons the use of refinery fuel gas is maximised as the only alternative would be to send these gases to the flare. Typically a significant fraction, but not all, of the refinery fuel demand is met by refinery gases. Some streams containing high levels of H_2S may have to be cleaned before use for both safety and environmental reasons.

In the same manner refineries produce a number of liquid streams that may be used as internal fuel. These streams generally comprise the heavier material residue from processes. The outlet for this material in products is limited and it has to be used in some manner. Direct use as a refinery fuel is cost-effective and efficient. The alternative to its use as an internal fuel is to convert it to higher value products. This requires specific investment in deep conversion plant as discussed below. The costs of such investment would not be justified for this internal fuel conversion alone and involves additional energy consumption and CO_2 emissions. It would therefore have to be considered as a part of a total rebalancing of the refinery product slate.

Additionally a refinery may produce coke in the FCCU and other catalytic reactors. Coke formed on catalyst is usually burned in a regenerator attached to the unit and cannot be considered a “fuel” in the strict sense because it is not able to be used in other equipment. However, for energy efficiency purposes it is common sense to recover energy from the combustion of this coke. Petroleum coke from a coker has potential for use as fuel and certain grades are generally exported as a solid fuel to supplement or replace coal firing. Alternatively petroleum coke can be used as feedstock to a gasifier. High grade coke has use in electrode manufacture.

For a refinery to consider switching to imported gas from using internal liquid fuel streams there are three main considerations to be balanced.

- First, is the supply security and price of a natural gas supply (which may not always be available) to augment the existing refinery fuel gas system. Note that, as described above, the refinery necessarily has a fuel gas make and, for general use, purchased natural gas has to be added to the fuel gas system and will be burned as a mixture.
- Second, there must be an alternative use for the material currently used as liquid fuel.

- Third, that combustion modifications for converting oil or dual-fired equipment to gas-only firing are practicable, without requiring a complete replacement of existing equipment. The main aspect here is the balance of radiative and convective heat transfer in furnaces, heaters and boilers. Compared to oil-fired systems gas-fired systems transfer less heat by radiation and the flue gas temperatures entering convective sections are much higher. Significant de-rating of equipment may be necessary for the change to gas and this impacts the energy available for steam raising or the refinery conversion processes. It may therefore be necessary to upgrade the tube banks which is a substantial cost. Additionally, the burner management system will generally also need to be replaced which can add between 50 and 150% to the conversion costs.

There are advantages in the converting to natural gas because maintenance costs are much lower for gas-fired than for oil fired units.

Viable alternative uses for material currently used as fuel are: for sale to the local market, for export, and for conversion within the refinery. The local market opportunities for residue sales can be limited, for example, inland refineries may lack access to a bunker fuel market. Export is a distress option which widens the price differential between the displaced fuel and the replacement natural gas. The ability to export depends on the market for residual feedstock. Some refineries with appropriate capacity and technology may supplement their crude intake with liquid residues. Conversion requires significant investment[15] in equipment to either upgrade the residue to higher quality products and comes with energy and CO_2 emission penalties. Typical upgrading processes are hydrocracking or coking where a coke by-product is obtained together with lighter upgraded products. The resulting coke disposal options have been outlined above.

Thus, conversion of a refinery to gas-firing must go hand in hand with the alternative use of residues. This is most favoured in already complex refineries investing in a total conversion strategy of which there are very few in Europe. Simpler refineries will be very exposed to the economic impact of alternative uses for liquid fuels and the price differential with imported gas. Very robust assurances would have to be in place to ensure that alternative uses remain available for conversion to be a viable option.

Even with “total conversion” if a coking process is not used (which is not a common situation in Europe) there will be some small volume liquid streams that will only be suitable for alternative uses (or ultimately disposal) if liquid fuel firing is not possible.

[15] CONCAWE report 03/09 [5] discusses the upgrading needed for residual fuel streams arising from marine fuels legislation

CONCAWE
Boulevard du Souverain 165
B-1160 Brussels
Belgium

Tel: +32-2-566 91 60
Fax: +32-2-566 91 81
e-mail: info@concawe.org
website: http://www.concawe.org