A Strategic Review of the Petroleum Refinery Industry Sector

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Statement of Use

This report reviews the environmental performance of the UK petroleum refinery industry sector in the context of world-wide best practice. Five practical options for reducing emissions are examined. The report will be used both externally and internally, by policy and operational staff, in the development of policies for the regulation of the petroleum refinery industry sector.

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Appendices

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FOREWORD

The Environment Agency has the strategic aim and duty to protect and enhance the environment. To support this work it also has a duty to undertake research and make the results available to others.

Processes with a significant potential to cause pollution are regulated by the Agency under provisions in The Environmental Protection Act 1990. Included within these processes are many in the petroleum refinery industry sector. Operators of these techically complex processes are required to use the best available technique not entailing excessive cost to prevent or minimise releases of polluting substances in order to achieve the best practicable environmental option.

The Agency, therefore, commissioned this independent report from Foster Wheeler Energy Limited to help it form an objective view of the current environmental performance of the UK refinery sector. The study has sought to identify significant issues that could affect the industry's environmental performance. Emissions, process options and abatement practices from a number of countries were investigated and worldwide best practice considered in the context of applicability to the UK situation.

Recent changes in the European transport fuel specifications and the UN sulphur protocol are evidently going to present the sector with some significant and conflicting economic and technical challenges. The results of this review will assist us to make appropriate regulatory decisions to ensure that the UK refinery sector uses the best available techniques not entailing excessive cost to protect the environment. It will also serve as an important contribution to the efficient regulation of the petroleum refinery industry sector.

Dr R J Pentreath
Chief Scientist and Director of Environmental Strategy

EXECUTIVE SUMMARY

European, including the UK, refiners have been struggling with over capacity and poor or negative margins for many years. This situation has been especially difficult since 1994. Overall, utilisation levels have risen recently but highly-efficient markets have resulted in any surplus product reducing prevailing prices and preventing improved profitability.

One result of low profitability is that refiners have, where possible, minimised capital expenditure and reduced operating costs. However, there has been, and will be, some expenditure to meet new environmental specifications on product quality and requirements for control of releases to the environment. The availability of plenty of light, low-sulphur North Sea crude has helped to minimise this expenditure. UK refineries have as a result now become dependent to a greater or lesser extent on light, low-sulphur feedstock to meet current product specifications and emission-release limits.

The continuing availability of this quality of crude is therefore a key factor in determining the future profile of UK refineries. An assessment of crude oil availability from the North Sea has been carried out and it is concluded that supplies will continue to be adequate at least until 2005, and probably beyond. It is to be expected that UK refiners will continue to depend mainly on North Sea crude during this period.

Given this premise, one of the most important factors for refiners during the period that this Review covers is the further tightening of product quality standards, particularly those for transport fuels. The European Commission and Parliament have recently agreed new standards, which are to become effective from 2000 and 2005. The 2005 standards include a sharp reduction in levels of benzene, aromatics and sulphur in gasoline and sulphur in diesel. It has been estimated that the increased refinery processing, mainly in the form of extra hydrotreatment, needed to meet the fuel specifications for 2005 would mean the UK refinery sector increasing its CO_2 emissions by between 2% and 4%. The supply of hydrogen required for this extra hydrotreatment will be an issue refiners will need to address.

The investment needed to meet these new standards will mark a watershed for European refiners. Most refineries will require modification as they will be unable to produce compliant product, even when processing the best quality crudes such as those from the North Sea. Depending on the overall profitability levels of the industry in the next few years, we could see a significant investment programme or a series of closures and mergers. If margins rise to the level which offers a reasonable rate of return then, besides investment to meet EU product quality legislation, further upgrades to the bottom of the barrel would be expected to occur. This would entail substantial expenditure. However, if margins remain depressed, some further mergers or closures might be expected, since, for some operators, it is likely to be uneconomic to carry out a heavy programme of investment under these circumstances.

In addition to these tighter EU product specifications there are a number of pieces of existing or prospective legislation that will require reductions in releases to air. These include:

- the existing Large Combustion Plant Directive (LCPD) 88/609/EEC covering SO_2 and NOx;
- the proposed new Large Combustion Installation Directive (LCID);
- the United Nations Economic Commission for Europe (UNECE) Second Sulphur Protocol (1994);
- the proposed EU Communication on Acidification (COA) strategy for Europe covering SO_2, NOx and ammonia. (This Communication is now likely to be in the form of a proposed National Emission Ceilings Directive;
- the proposed EU Directive on 'The reduction of the sulphur content of certain liquid fuels' (regarding fuel oil).

UK refineries range from a relatively simple hydroskimming refinery to cracking and bottom of the barrel upgrading refineries. Upgrading refineries are more complex and have proportionately larger mass emissions as cracking and bottom of the barrel upgrading are more energy demanding than hydroskimming.

As requested by the Environment Agency a refinery release inventory has been developed as part of this Review using information from the Public Register. This shows that in 1996 reported UK refinery emissions of SO_2 were about 120 000 tonnes, which represents about 5% of national emissions. In respect of NOx, reported refinery emissions were about 30 000 tonnes in 1996 forming approximately 1.3% of national emissions. Reported particulate releases constitute about 0.8% of national emissions based on 2600 tonnes from refineries in 1996. Total sector CO_2 releases were estimated to be 2.6% of the national emissions. The inventory also shows that on a refinery-sector basis approximately 54% of SO_2 releases are from combustion processes, 17% from FCCUs (fluid catalytic cracker units), 19% from SRUs (sulphur recovery units) and about 10% from various other sources. Similarly for NOx on a sector basis, 81% of releases come from combustion, 15% from FCCUs and 14% from other sources including calciners. Not all emissions are reported (notably particulates) and insufficient data were available for flare emissions to be considered in the above numbers.

A number of comments have been made in this Review concerning the data on the Public Register. For example, the Environment Agency may wish to consider requesting, as a standard requirement, a VOC (volatile organic compound) release inventory and a sulphur balance for each refinery, information that only a few refiners presently supply. It was not possible to complete an extensive inventory of releases to water owing to lack of consistent data on the Public Register.

Data from the Public Register also show that for some combustion plant and FCCUs actual 1996 reported release levels, especially SO_2, were significantly below the release limits set by the Environment Agency. While there may be good reasons for this, it could also mean that potentially significant increases in current refinery releases to air could occur within existing limits. However, any revision to limit levels, with this in mind, would need to take account of a refinery's complexity, particularly the processing scheme and product slate.

Meetings were held with the local Environment Agency inspector responsible for each refinery as well as with all refinery operators. Notes of these meetings have been sent separately to the Environment Agency and although they are not included in the Review, the information gained, which was not confidential, has been used where appropriate. Similarly, notes of meetings with operators have been made and sent to them individually and they are not included in this document. However, a summary of the main points made by most operators is included in Chapter 2. The main points they emphasised included the fact that they are concerned to have clear target/limits in respect of environmental releases and that these should be based on 'sound science'. They also said they had no major investment plans in the near future, i.e. the next 12 months.

Comparison of UK abatement practice with world-wide refinery best practice in such countries as the USA, Scandinavia, Japan, and the Netherlands shows that the UK lags behind in the levels of abatement applied. Scandinavian refineries represent the world's best practice. The SO_2 release levels, for example, from the Mongstad refinery (Norway), which has a crude capacity of about 38 million barrels/year, are about 2000 tonnes/year compared to UK refineries which have SO_2 releases ranging between 5000-20 000 tonnes per year with crude capacities of 28 to 98 million barrels/year. However, it should be noted that many of these countries with which the UK is compared, including Scandinavia, have particular, in-country, reasons for requiring very low release levels.

Based on analysis of the refinery release inventory prepared for this Review, a number of options (or strategies) for reduction of releases have been developed. The effects on the UK refinery sector as a whole of applying these options in terms of reduced release levels, cost, and economic effects have also been assessed. In order to make this overall assessment, the effects on each individual refinery were considered and these components were then aggregated. Information on the assessment of the effects on each refinery is not included in this Review. Where data were missing from the Public Register, estimates have been made taking into account the size and configuration of the refinery concerned. The abatement options that were assessed are set out below.

(1) The reduction of the sulphur in the fuel oil fired on refineries to 1%. Typically this might involve substituting a vacuum residue with a North Sea atmospheric residue.

(2) Substituting fuel oil firing with natural gas or liquefied petroleum gas (LPG) and the sale of excess fuel oil. It is assumed fuel gas is already being fired to its maximum extent. (It should be noted that most UK refineries are reasonably well situated to receive natural gas from the National Transmission System (NTS). However, refineries in South West Wales currently have no readily-available commercial natural gas supply.)

(3) Abating key stacks, typically two, using wet gas scrubbing with caustic soda or equivalent.

(4) A combination of Options 2 and 3, whereby fuel oil of elevated sulphur content would be fired in stacks fitted with wet scrubbing while all remaining combustion units would be fired on fuel gas, supplemented if required with LPG or natural gas.

(5) To achieve the reductions required by 2010 under the proposed EU Large Combustion Installation Directive and the Communication on Acidification.

Overall it is considered that the first four options represent a feasible strategy for most refineries. The abatement measures involved in the fifth option would include firing clean gas in combustion plant and installing selective catalytic reduction in the flue gas streams of combustion plant. Scrubbing of FCCU flue gases would also be needed together with a range of other improvements including upgrades to sulphur recovery systems. As a result, this fifth option represents an order of magnitude cost increase for refiners compared to the first four options.

It should be noted, that not every option can necessarily be applied to every refinery, e.g. the import of natural gas would be difficult at the refineries in South West Wales. Indeed, any individual refiner if required to reduce releases to air may opt for a combination of abatement measures which, while not the same as any of the options, could have much the same effect.

Evaluation of each of the Options 1 to 4 across all the refineries gave a range of reductions for each of the main pollutants as shown below. The actual percentage reduction would depend on the option selected.

Range of possible percentage reductions from 1996 levels

Pollutant	Options 1 to 4
SO_2 (sulphur dioxide)	30 to 52%
NOx (oxides of nitrogen)	24 to 39%
Particulates	33 to 48%
CO_2 (carbon dioxide)	19 to 37%

Aggregation of the likely best abatement option for each refinery selected from Options 1 to 4 would give an industry sector reduction of 52% for SO_2 and 39% for NOx.

The economic effect of each option, if applied across all refineries, was evaluated on the basis of cost per barrel of oil processed by the industry as a whole. For Options 1 to 4 this showed costs ranging from 3p to 19p per barrel of oil processed. Option 2, with natural gas as the supplementary fuel, proved to be generally the cheapest option, after making due allowance for making a connection to the natural gas National Transmission System although, as noted above, this could not be applied to refineries in South West Wales. The aggregated cost of using the likely best option from Options 1 to 4 at each refinery, which acknowledges the difficulty of gas supply to the South West Wales refineries, gives an industry cost per barrel of oil processed of 4p. The cost per barrel for the refinery sector of implementing Option 5 would be 29p. Cost in this context is annual operating cost plus capital cost where this is amortised over five years.

The cost to the refinery sector of each option, per barrel of oil processed, was compared with the profitability of the industry as a whole. In 1994, according to data from United Kingdom Petroleum Industries Association (UKPIA), profit margins equated to about 72p per barrel. The cost of implementing the evaluated options would represent between 4% and 26% of the 1994 sector profits, with the cost of implementing Option 5 representing 40%. However, in 1995/6 UKPIA reported profits of nearly zero; therefore, in this case, the costs of implementation would be particularly significant.

It should be recognised that this economic analysis has been restricted to assessment of the refinery industry sector only. It has not considered the broader economic base of the operating companies which own the refineries, which usually include oil production facilities and downstream chemicals manufacture.

The reductions offered by the options were compared with the requirements of current and potential legislation. This showed that, if implemented across all refineries, Options 1 to 4 would provide the required levels of abatement to meet the existing LCPD 88/609/EEC and the UNECE Second Sulphur Protocol (1994). This is based on the assumption that the UK refinery industry has met the reductions that are required by the LCPD and the Protocol up to the present time. None of Options 1 to 4 would provide the level of abatement needed to meet the requirements of the proposed new LCID and the EU COA acidification strategy. Only Option 5 would do this.

If installed to meet the 2005 fuel specifications, FCCU hydrotreatment would provide about a 90% reduction in SO_2 releases from the FCCU regenerators. However, due to its high capital cost it is not seen as a measure that can reasonably be applied for the sole reason of abatement.

In the longer term gasification is seen as a possible solution for the disposal of high sulphur residue oils. It would produce 'syngas', which could be used as a clean gaseous fuel for combustion as well as providing hydrogen for hydrotreatment and carbon monoxide feedstock for organic chemical synthesis. However, current economic factors are very much against the process being selected by refiners in the short term except perhaps on a co-operative basis. These factors include the relatively high capital and operating cost of the process, the reasonable market for fuel oil still prevailing, the relatively low cost of natural gas as a fuel for combustion, the good supply of light sweet North Sea crude oil, and the small price differentials currently existing between the sweet crudes and the heavier sourer crudes. If any of these factors were to change significantly, and the emission levels proposed under the LCID and COA were to become firm requirements, refiners might consider gasification more seriously.

The combustion of 'clean' gaseous fuels offers many advantages over heavy fuel oil including lower SO_2, NOx, particulates, heavy metals and CO_2 releases. However, the amounts of refinery fuel gas available for combustion in refineries may decrease due to its hydrogen component being required for the extra hydrotreatment needed to meet the 2005 fuel specifications. Some refiners may invest in new reforming plant to provide the extra hydrogen required; however, others may wish to burn more fuel oil. Even if low sulphur fuel oil is fired this could still lead to increases in levels of NOx , particulates and heavy metals unless additional abatement is provided.

The optimum route for the reduction of CO_2 emissions in the longer term seems likely to be the combustion of gaseous fuels with high hydrogen/carbon ratios such as refinery fuel gas, natural gas, LPG or hydrogen itself possibly produced from reforming or gasification processes..

There are reports that significant advances have been made recently in hydrogen/oxygen fuel cell technology for the powering of vehicle transport. If fuel-cell-powered vehicles should prove technically and commercially viable in the next five to ten years, the major effect on refineries would be the need to supply the new fuel to the required specification, while maintaining existing fuel types.

Postscript

Since completing this Review a recent change has been made by the EU to the proposed Large Combustion Installation Directive. Originally this specified emission limits for SO_2 and NOx releases from existing and new large combustion installations including gas turbines. The proposal has recently been modified so as not to apply to existing plant. However, demanding National Emission Ceilings, designed to be met by the year 2010, are proposed by the EU as a result of the Communication on Acidification. The softening of the LCID requirements therefore will only have a relatively minor effect on the evaluations made in respect of Option 5 in this Review.

Key words

refinery
petroleum
emissions
abatement
oil

1. INTRODUCTION

This Strategic Review of the Petroleum Refinery Industry Sector has been carried out by Foster Wheeler Energy Limited on behalf of the Environment Agency. Specifically, Foster Wheeler was requested to:

- Review the UK petroleum refining industry and compare the UK refinery practice with best practice around the world.
- Prepare a national inventory of releases (including both authorised and fugitive releases) made by the sector to air, water and land and indicate which pollutants have the greatest environmental impact.
- Prepare a range of strategies to reduce the releases from the refinery industry sector. These should concentrate on the pollutants with the most significant environmental impact.
- Estimate the overall costs of each of the most significant pollution release reduction strategies and undertake detailed economic analysis of the implications.
- Predict the probable effect upon the release inventory of implementing the most significant pollution release reduction options.
- Examine strategies to reduce pollution releases from the petroleum refinery sector in the longer term (25 years).

Chapter 2 of this Review discusses the important factors currently affecting UK refineries such as crude oil supply, environmental legislation, product demands and refinery economics.

Chapter 3 includes reviews of the current levels of abatement applied to UK refineries and an inventory of their releases to air.

Chapter 4 compares UK abatement practice with world-wide best practice. Countries such as the USA, Japan, the Netherlands and Scandinavia are considered.

Chapter 5 discusses pollution reduction issues for refineries, techniques for pollution reduction and their costs.

Chapter 6 sets out five options (or strategies) for possible pollution reduction and assesses their effectiveness and cost with current and proposed environmental legislation for the refinery sector as a whole:

Chapter 7 discusses pollution reduction technology and associated issues in the longer term.

A number of important points should be noted regarding the Review. These are as follows-

(a) The UK refineries considered in this Review are BP Grangemouth, Phillips Petroleum North Tees, Lindsey at Killingholme, Conoco also at Killingholme, Shell Stanlow, BP Coryton, Shell at Shell Haven, Esso Fawley, Mobil Llandarcy, Texaco Pembroke and Elf at Milford Haven. Gulf also at Milford Haven has already been closed and has therefore not been considered in detail. Shell Haven is planned to close in 2000 but has been included as part of this Review. It should be noted that while this Review has included BP Grangemouth, this refinery is authorised by Scottish Environment Protection Agency (SEPA) and not by the Environment Agency which is responsible for refineries within England and Wales only. The inclusion of BP Grangemouth is designed to complete the overall picture of the UK refinery industry.

(b) It has been prepared using only information in the public domain. In particular it is based on data for releases to the environment taken from the Public Registers held by Environment Agency offices in Britain. These release data are for the year 1996 representing the latest and most complete set of information available at the time this Review was prepared.

(c) The Review, as far as possible, takes account of prevailing (1997 to 1998) refinery practice, economics, crude oil supply, market trends, environmental legislation including likely future legislation, product demand, possible pollution abatement techniques and the views of the refinery operators. It should be noted that, like all industries, any of these factors can be subject to relatively rapid change.

(d) Oil refineries are extremely complex operations, probably the most technically and operationally complex of all industry sectors, with a large number of integrated, high cost processing units producing a wide range of mainly combustible products in very large volumes. Each refinery will therefore have many constraints which will influence its preferred methods of dealing with environmental factors and pollution abatement. This Review addresses these subjects as far as possible when choosing the five possible pollution abatement options, although in covering the whole refinery sector it is necessarily generic in its approach. It is to be expected that refiners could offer alternative solutions and strategies to those contained in this Review which could achieve similar abatement results. The complexity of this Review is, to a large extent, due to the complexity of the industry sector.

(e) Due to the very site-specific nature of local air and water quality, no assessment has been made of the current effects individual refineries may be having on the local air and water quality in their areas, nor on the improvements the possible abatement options might have on local air and water quality. To do this would require a detailed assessment of each refinery's releases using dispersion modelling techniques.

(f) Discussions have been held with each of the UK refinery operators together with the UK Petroleum Industries Association (UKPIA). Their views are set out in Chapter 2 of this document.

(g) Little major new investment is envisaged in the UK refinery sector in the immediate future (the next one to two years). This Review therefore mainly addresses existing refinery plant and its operation.

(h) While the information given in this Review is essentially based on data for individual refineries taken from the Environment Agency Public Register and elsewhere within the public domain, the data have been analysed so as to present further information and comment for the whole of the UK refinery sector.

(i) The Environment Agency terms of reference for this Review ask that the options and strategies prepared should concentrate on the pollutants with the most significant environmental impact. A number of UK Government and European environmental reports and legislation give guidance on this matter, such as the proposed EU acidification strategy, the second UNECE SO_2 protocol and the proposed Directive on Large Combustion Installations. Guidance from these documents has therefore been followed rather than developing this subject afresh in this Review.

(j) This Review has assumed that the reader has a basic understanding of oil refinery operations and processes. Readers less familiar with this industry sector may find the descriptions and explanations helpful that are given in Appendix 2 of this Review, and in the HMSO Chief Inspectors Guidance Note for Processes Subject to Integrated Pollution Control entitled ‘S21.10 - Petroleum Processes: Oil Refining and Associated Processes’.

2. KEY FACTORS AFFECTING UK REFINERIES UP TO 2005

There are a number of important economic factors as well as significant current and future environmental legislative measures which will directly and indirectly affect refineries and their releases to the environment. These include:

- future crude quality and supply;
- future markets for fuel oil;
- refinery capacity and economics;
- product quality changes;
- current and future environmental legislation.

These factors are discussed in further detail below.

2.1 Crude Supply and Quality

Almost all the UK refineries are currently processing North Sea crude oil to a greater or lesser extent. Compared with other crude oils produced around the world North Sea crude is both light (contains a higher proportion of lower boiling point fractions) and sweet (low in sulphur). The effect of North Sea crude processing on UK refineries is threefold. First, due to the relatively low sulphur content of the crude, SO_2 emission limits are generally met comfortably by most refineries. Second, the crude produces more of the profitable light transportation fuels (gasoline and diesel) in the first stage of crude processing and these require less hydrotreatment to remove sulphur. Third, the quality of the resulting residue is such that it is relatively low in sulphur and permits greater conversion to these lighter transportation fuels and a correspondingly lower proportion of fuel oil. By way of simple illustration, a given refinery configuration processing a North Sea crude could have a 20% fuel oil yield, whereas the same refinery processing heavy Arabian crude would have a 50% to 70% fuel oil yield. In reality each refinery has its own specific configuration and crude diet, and a few UK refineries are processing heavier crudes in combination with North Sea crude. UK refiners are dependent upon North Sea crude to meet current and future market demands and sulphur emission limits.

It is therefore important to assess whether light/sweet crudes will continue to be available to UK refineries.

To this end an assessment has been undertaken of both the future production of North Sea crude and the likelihood that UK refineries can rely on supply of this crude in a competitive world market place.

2.1.1 UK Production

The North Sea is a significant supplier (approximately 20%) of non-OPEC (Organisation of Petroleum Exporting Countries) crude oil. Although in general the qualities of North Sea crude are being maintained, more recently the Chevron Alba Fields and Statoil's Heidrun Field have produced acidic crude oil and special arrangements have had to be made to refine this. High acidity crudes are forecast to rise in production from 0.5 million barrels per day to 1.1 million barrels per day by the year 2000.

Looking to the future, Figure 2.1 shows a current forecast of total North Sea crude production up to 2005. It shows that Norwegian output is due to remain at or near current levels and that UK crude oil output, after a peak in 1998, is forecast to decline steadily but still remain at a high level in historical terms.

The rate of decline in the volume of UK supplies post-2000 will be inevitably a matter of debate. Pessimists will argue that there are too few new small fields to compensate for the decline in output from older large fields.

Sir David Simon, until quite recently chairman of BP, said in June 1997: "Finding and development costs in the UK Continental Shelf have fallen by $8 per barrel since 1990. That has been enough - in combination with a creative and responsive tax regime - to sustain both exploration and development activity. Production looks set to increase for at least another two years and the UK should still be producing as much as 2 million barrels of oil per day even in 15 years' time".

Costs of North Sea production have fallen due to both technical improvements (e.g. 3-D seismic, horizontal drilling, sea-bed production facilities, increased recovery rates, floating production vessels etc.) and commercial improvements ('out sourcing', alliance contracts etc.). For instance, Figure 2.2 illustrates the dramatic cost reduction in subsea facilities achieved in the last ten years.

Figures 2.3 and 2.4 show the level of exploration activity and success respectively.

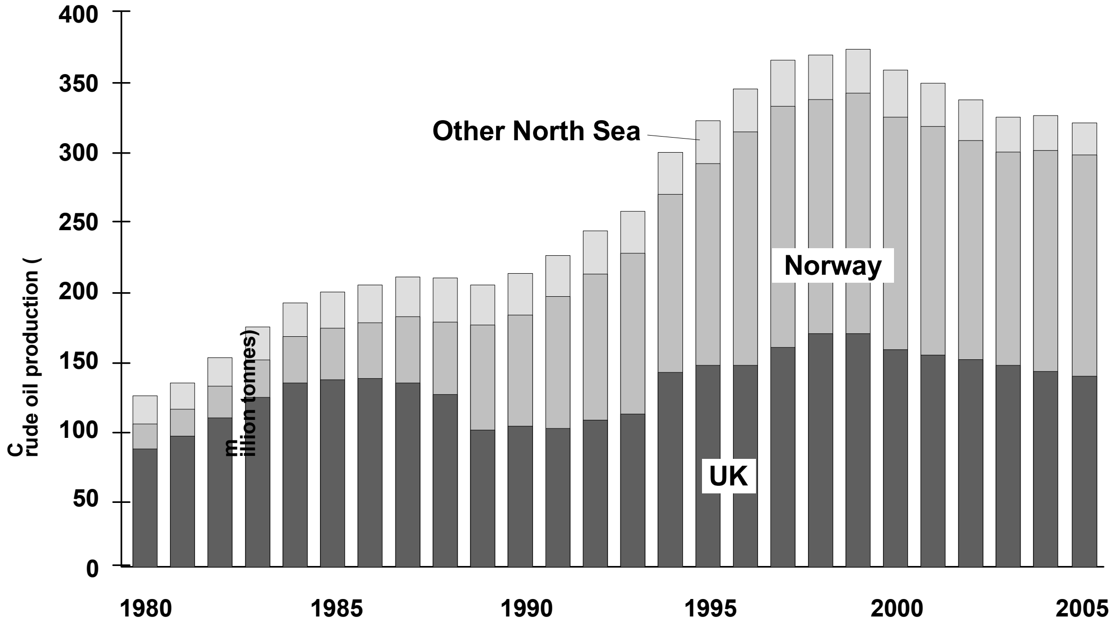

Figure 2.1 Forecast North Sea crude oil production (Wood Mackenzie)

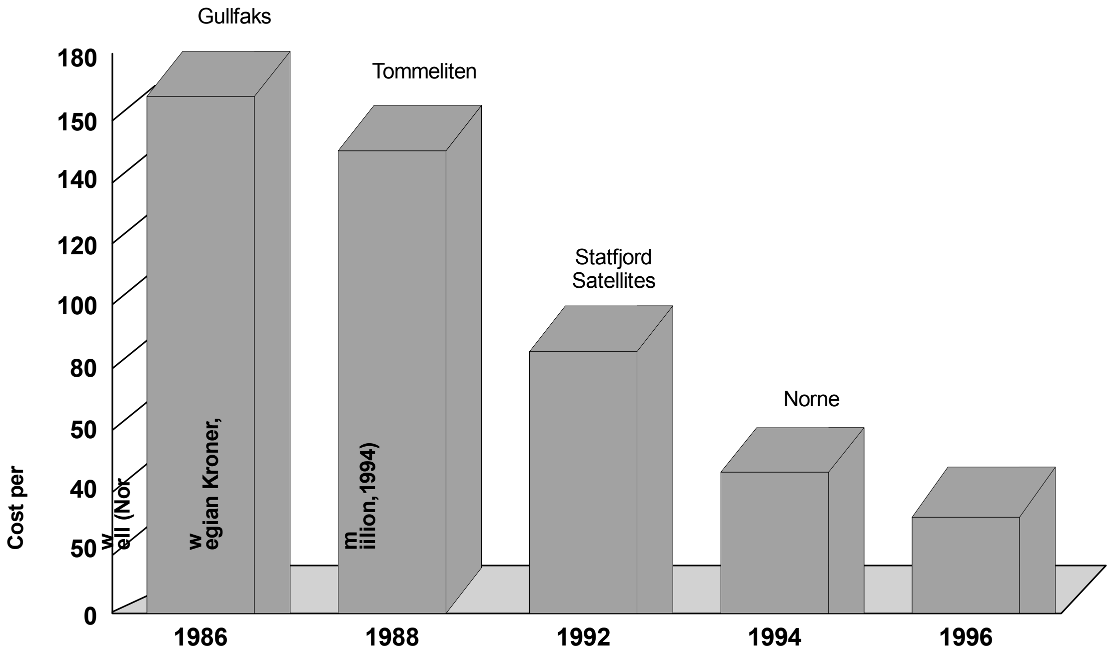

Figure 2.2 Reduction in Subsea Production Costs for Norwegian Oil Field Developments (Statoil)

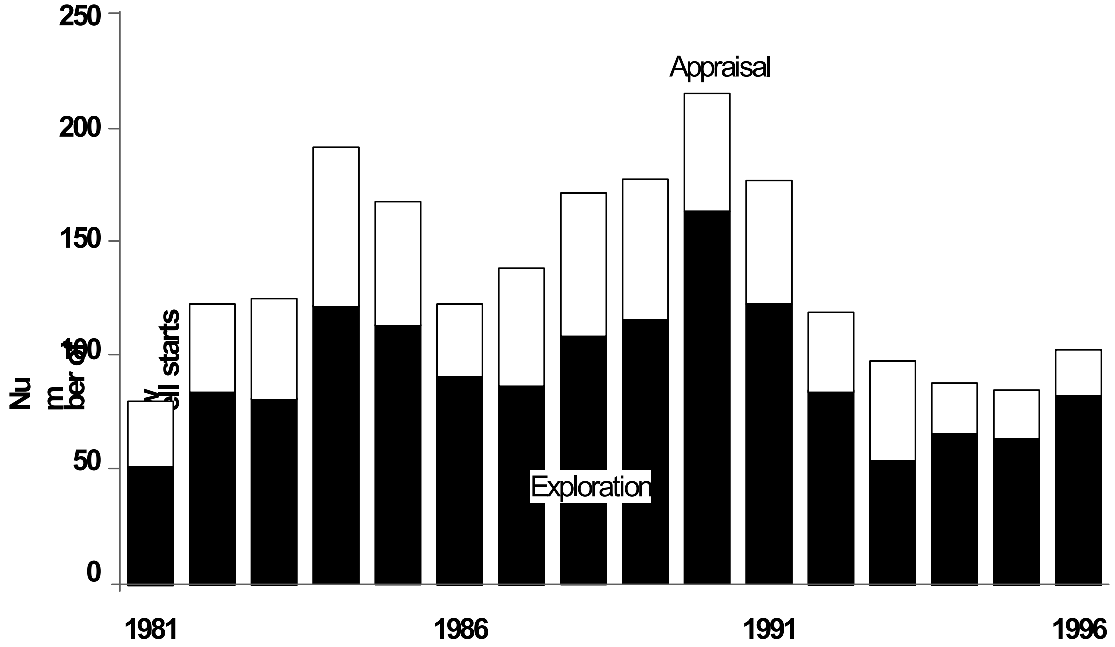

Figure 2.3 Annual exploration and appraisal wells in UK North Sea (Wood Mackenzie)

The history of the North Sea shows that forecasts of total oil production have consistently proved to be underestimates. In Figure 2.5, for instance, UK consultant PEL shows widely-accepted industry forecasts produced in 1984 and 1988, both of which turned out to be underestimates compared with actual levels. So far North Sea production has borne out the conservative reputation which major oil companies have regarding their public announcements of level of reserves and likely levels of future production.

In 1996 the UK Offshore Operators, Association (UKOOA), which represents oil companies to the government, said that the UK is expected to remain self-sufficient in oil until at least 2010. Since their previous report to government in 1989, the level of economic UK oil reserves has increased by 5.7 billion barrels. Two thirds of this increase is from improved expectations from existing fields. A major contribution has come from innovative technology. In 1996 UKOOA said that about half the total oil discovered in the UK sector has been produced over the last 25 years.

In August 1997, the Norwegian government said the outlook for the petroleum sector is “more robust” than ever before. Officially Norwegian oil output is forecast to peak at 3.7 million barrels a day around the turn of the century and stay at that level until 2001. However, the director general of the Ministry of Petroleum and Energy said, “I can’t exclude the possibility that the peak might be higher and that output might stay there for a longer period”.

Two recent changes affecting North Sea crude oil supplies are production of ‘condensate’ and production from the new West of Shetland Basin. The first two West of Shetland fields to come on stream produce crudes which are heavy but still sweet. The latest UK government estimate puts West of Shetland recoverable reserves at about 26% to28% of total UK reserves.

Many of the new UK fields are ‘condensate’ fields for which American Petroleum Institute(API) number and sulphur information are not available. Condensate is liquid production, which is very light and does not have the ‘long tail’ of heavy hydrocarbons found in conventional crude oil. Having more in common with light oil or natural gas production, most condensates produced round the world have extremely low sulphur contents. The Bruce condensate from the UK North Sea is 0.02% sulphur and is likely to be typical for the North Sea.

In 1997 consultants AD Little re-examined their forecasts of Europe’s crude oil slate (diet) to refineries following publication of the Auto-Oil recommendations - see Section 2.2 below for details. The original studies were done in 1992 to 1993. The consultants found that the availabilities of sweet crude oils are now higher than previous expectations because North Sea production is higher than forecast. The extended life of production from the North Sea is expected to affect the whole of Europe. For all parts of Europe, the crude slate in 2000 is forecast to be lighter than in 1995. This end-of-century improvement will effectively delay the onset of a more sour crude slate for the whole of the European refining industry over the period 1995 to 2005.

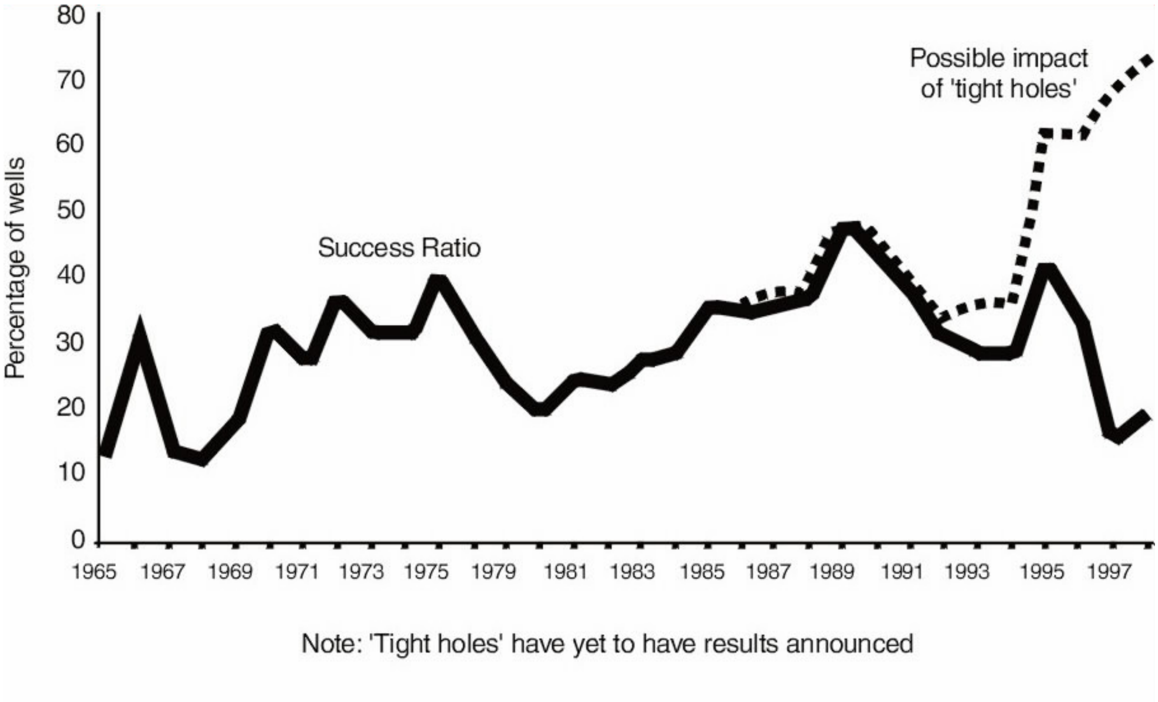

Figure 2.4 UK exploration success ratio (Wood Mackenzie)

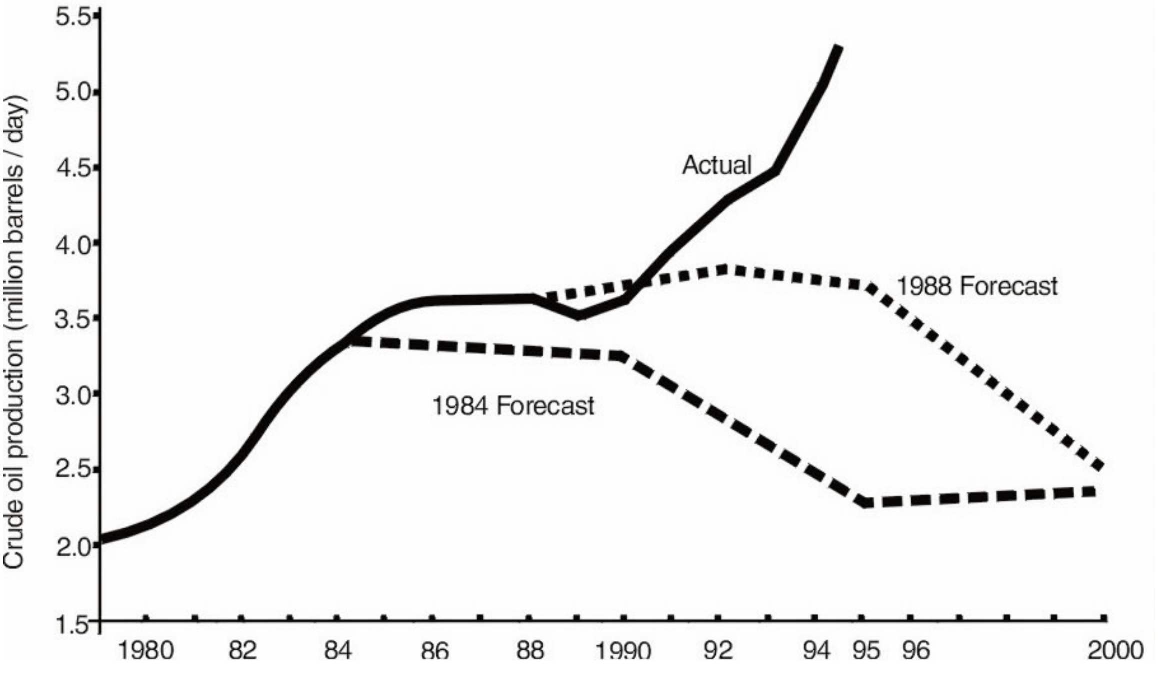

Figure 2.5 Past industry forecasts of North Sea oil production (PEL)

It can therefore be concluded that there is more than sufficient light/sweet crude remaining in the North Sea to meet UK refinery demand up to and beyond 2005.

2.1.2 Effect of Global Oil Supplies on European Crude Availability to 2005

Although supplies of North Sea crude are sufficient for the foreseeable future, the question arises whether UK refiners are likely to continue actually to use this local North Sea crude. For instance, by 2005, North Sea producers may prefer to export most of their light/sweet oil to other regions of the world or, conversely, will UK refiners choose to import large volumes of lower-quality, higher-sulphur crude from non-North Sea sources especially if there is a significant price differential between these and North Sea crude.

Current UK crude oil trade pattern

Currently the UK is both an importer and exporter of crude oil. About 570 million bbl per annum of crude oil is currently refined in the UK, of which about 250 million bbl per annum is imported. These imports are overwhelmingly light/sweet crude from the Norwegian North Sea. Exports from the UK are currently about 500 million bbl per annum (twice the level of imports), mainly destined for coastal ports in NorthWest Europe and deep-water exports to the USA.

The trend over the last five years has been for UK exports to grow strongly while imports have remained fairly steady. Exports started to increase from about 375 million bbl per annum in 1993 when a surge of UK North Sea capacity came on stream. During this period exports to the USA increased from 20% to 27% of the rising total while exports to North West Europe fell in relative terms from 50% to 44%. Over the same period Norway's share of exports to the UK increased from 50% to over 67% while imports from the Middle East fell from 12% to just 6%.

The observed trading pattern of UK refineries using largely North Sea crudes is understandable on the basis of logistical costs. The UK is the closest refining centre to most North Sea oil production and most North Sea oil export pipelines land in the UK, offering the lowest delivery costs to the refinery gate. For offshore fields using direct tanker loading, the tankers are usually designed for regional rather than international trading. It is because of this that the UK will continue to compete strongly for North Sea crude even in the scenario that there is increased competition in Europe for this crude due to EU fuel specifications, (i.e. European refineries currently processing sour crudes may wish to switch and process sweet crudes so that specifications can be more easily attained).

Summarising, the UK crude supply industry is fairly 'self-contained': most oil refined in the UK is sourced locally from the North Sea. Imports from Norway are increasing but dependence on Middle East oil is both low and falling. A base load of oil exports goes to local European countries while, in recent years, the USA has taken most of the UK's increased production. The UK's strong exports to the USA are aided by American-owned multinational oil companies which own or produce over a third of UK production.

Therefore, if current trends are any guide to the future, any significant increase in imports by the UK are likely to come from Norway and any major increases in exports are likely to go to the USA.

Current global crude oil trade pattern

Turning to global crude oil trade, Figure 2.6 shows a 'helicopter-view' of the world's biggest importers and exporters in 1996. Looking at the information on a regional basis, the figure shows that Asia imports the largest amount of crude oil and is heavily dependent upon the Middle East. Western Europe imports a significant volume but from several sources, such as the Middle East, Africa and the Former Soviet Union. The USA imports a total volume similar to Western Europe but from a more diversified range of sources, i.e. Latin America, the Middle East, Africa, Mexico, Canada and the North Sea.

The trend in these data over the last five years shows that the overall world pattern has remained basically similar but imports by Asia from the Middle East have increased by 40% as Asian economies have developed. In contrast Western Europe has reduced imports from the Middle East while increasing imports from the Former Soviet Union. Similarly, the USA has slightly reduced imports from the Middle East but increased imports from other sources, i.e. Latin America, Mexico, Africa and the North Sea.

Current global crude oil quality

Quality of crude oil is a key factor which drives international oil trading because the price of individual crudes depends upon their quality. The commonly-quoted headline 'world oil price' is in fact the price of one particular crude - Dubai - a medium-sulphur crude from the Middle East. As such, Dubai crude usually has a medium price within a range of current crude prices. For instance, Dubai is usually about $2 per barrel more expensive than a high-sulphur/heavy crude but about $2 cheaper than good-quality light/sweet crudes, such as Brent from the North Sea. These crude-oil price differentials, or 'spreads', reflect the value of the crude to an average refiner: a barrel of low-price heavy/sour crude will require significant refining whereas a barrel of high-price sweet/light crude is 'easy' to refine.

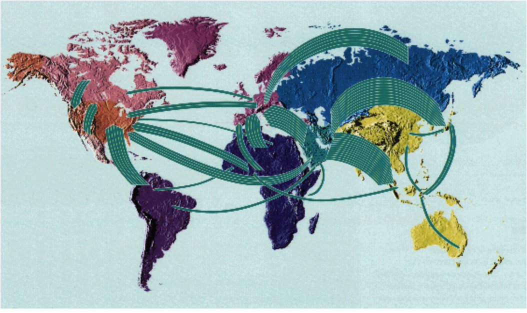

Figure 2.6 Major oil trade flows in 1996 (BP Statistical Review of World Energy 1997)

Crude oil price differentials are a complex subject. For instance, besides light/sweet crudes and heavy/sour crudes there are also other combinations, e.g. light/sour crudes and heavy/sweet crudes. The consequence is that if differentials are high, then UK refiners may be 'outbid' to acquire North Sea crude. At the same time other UK refiners, with sufficient spare refinery upgrading capacity, may choose to import cheaper high-sulphur crudes and add value by processing.

Regarding trends in global crude oil quality, Wood Mackenzie has suggested that the average world crude quality became marginally lighter and sweeter during the 1990s. This was the result of increases in production of non-OPEC light/sweet crudes, including the North Sea, and a policy shift by Saudi Arabia and Iran to maximise their lighter crude output in order to increase revenues after the Middle East Gulf war in 1991.

USA consultants Purvin and Gertz suggest that this shift to lighter crude production combined with over investment in upgrading capacity during the early 1990s has resulted in very narrow heavy/light and sweet/sour crude price differentials. More than anything else these two factors have led to poor refinery profitability in the early 1990s on a world-wide basis including the UK.

Future global scenarios to 2005

Two alternative scenarios might be considered for the future development of global crude trade and its implications for the UK up to 2005. These two scenarios might be termed, 'The Conventional Wisdom' and 'More Independent USA'.

The conventional wisdom scenario

This is based upon light/sweet crude oil becoming more scarce. Two-thirds of world oil reserves are located in the Middle East, where the oil is predominately heavy and sour, while only about one-third of global production currently comes from the area. Therefore over time, as reserves run down elsewhere, an increasing proportion of global production must become heavier.

Within this scenario, oil production in non-OPEC countries declines, while OPEC remains a disciplined organisation and firmly 'in the driving seat'. The USA, with declining domestic production, will increase imports mainly from the Middle East. World oil prices will tend to rise, Middle East government finances will improve, the need to 'over-produce' light crudes will decline, shut-in heavy oil fields will re-open and crude price differentials will widen.

Under these circumstances, those UK refiners with suitable upgrading capacity may choose to import cheaper heavy/sour crudes while minimising use of expensive North Sea crudes.

Recent evidence supporting this scenario includes:

- global oil demand is increasing quite rapidly (1.5 million barrels per day);
- Middle East reserves increased by about one-third in the late 1980s;
- several 'new' production areas will produce sour crude, i.e. deepwater US Gulf of Mexico, and Venezuela.

The more independent USA

The second scenario is based upon an extension of recent trends which appear to show that oil reserves are widely dispersed around the globe. In particular, within this scenario, the USA has the opportunity to reduce its dependence upon Middle East oil by developing reserves throughout North and South America and the Atlantic basin.

In this scenario, there is no potential global shortage of crude supplies. Current and future USA demand (see Table 2.1) is, and is likely to be, met by increased oil production from many sources throughout the Western Hemisphere - from deepwater US Gulf of Mexico, Canada, Mexico, Venezuela, Colombia, West Africa, North Africa and the North Sea. Middle East producers increasingly redirect their crude exports towards expanding Asia and reduce exports to the Atlantic basin. With the potential 'loss' of American markets and Venezuelan membership, OPEC is weaker, crude prices tend to fall. Shortage of revenue encourages Middle East producers to maximise production of higher-price light crudes and to restrict supply of low-price heavy/sour crude. Crude price differentials remain comparatively narrow.

In these circumstances, UK/European refiners will have both less access to Middle East heavy/sour crudes and limited financial incentive to refine it. The UK is likely to increase exports to an import-hungry USA and possibly compensate by increasing imports from Norway.

Recent evidence supporting this scenario is listed below.

- Some 'new' production in the Atlantic basin is of sweet crude, i.e. Colombia, North Africa, deepwater West Africa, North Sea.
- Potential supply of crude to the USA is greater than potential USA import demand.
- Export of sweet West African crudes has switched from the Western Hemisphere to Asia as western area sources replace this supply.
- Iraq traditionally exported crude to Asia and would be expected to resume in future.
- Ecuador and Gabon have already left OPEC.
- Multinational oil companies have regained entry into several OPEC countries.
- Asia often pays a higher price for Middle East crude than the West.
- Venezuela is ignoring OPEC quotas.
- American refiners are investing in upgrading (cokers) to process local heavy/sour crude.
- Canada and Venezuela are investing in synfuel/extra-heavy crude upgrading projects.
- Canadian crude exports to the USA are growing, particularly from new East Coast fields.
- NAFTA trade agreement eases energy trade between the USA, Canada and Mexico.
- USA plans to 'extend' NAFTA to Latin America by creating FTAA by 2005.
- Technology is dramatically reducing oil production costs for non-OPEC countries.
- There is growing world-wide production of sweet condensates.

Table 2.1 Potential changes in crude supplies to USA from 1995 to 2000

Change in total refinery throughput barrels/day	**Change in USA oil production** barrels/day	**Increase in imports to the USA** barrels/day
650 000	200 000	450 000

Source PEL January 1997

Of the two scenarios the second is thought to more closely reflect what is likely to occur. It is foreseen that the number of 'new' non-OPEC oil-producing countries will keep growing which ultimately adds to supply flexibility and weakens oil prices. The next major newcomers are likely to be Azerbaijan and Kazakhstan which are expected to be exporting to Europe by 2005.

Furthermore, even if the first scenario does turn out to be closer to the truth, then the Middle East oil exporters will still be most dependent upon Asian customers. Therefore if in the future Asian/Chinese growth slows down, as it recently has, the Middle East suppliers will be directly affected and oil prices/differentials will tend to fall even in this scenario.

In conclusion it is foreseen that while fluctuations will occur, crude oil prices and price differentials will continue to be low. As a consequence this will provide little financial benefit to UK refineries. The UK oil industry is likely to remain fairly 'self-contained' and UK refineries will continue to run local North Sea crudes to 2005 and beyond.

2.2 Product Quality Changes

Almost all fuel products of petroleum refining have been or will be affected by legislation aimed at reducing environmental impacts of fuels at their point of use. It is at the refineries where a response to these requirements will be met. The following section outlines current and possible future legislative effects on product quality.

2.2.1 Road Transportation Fuel Quality

The continued pressure for clean fuels is manifest in the recent EU legislation amending Directive 93/12/EEC relating to the sulphur content of certain liquid fuels. The amendment details gasoline and diesel specifications for the year 2000 and 2005, as shown in Tables 2.2 and 2.3. EU refiners will therefore be required to meet tighter specifications for the year 2000. By the year 2005 they will be required to meet what many observers regard as the toughest transportation fuel specifications in the world. This inevitably will also require EU refinery processing operations to be among the most complex and sophisticated in the world.

The recent EU legislation offers some derogation in respect of time for the implementation of the new specifications, subject to EU approval. However, for this Review it is assumed that the EU specifications in respect of the UK will apply, and that by the year 2005 refiners will be producing fuels to meet the ultra-low sulphur levels.

The implications of these 2000 and 2005 Specifications on UK refineries are now discussed below.

Table 2.2 EU Requirements for gasoline

Item	Current limits 93/12/EEC	Max. Limits for 2000	Max. Limits for 2005
Sulphur ppm	500	150	50
Olefins % by vol	None	18	*
Aromatics % by vol	None	42	35
Benzene % by vol	5	1	1

* Specification not yet set for 2005. This will be set following report by Auto Oil II programme.

Note: Certain other limits also apply but are not included above.

Table 2.3 EU Requirements for diesel

Item	Current limits 93/12/EEC (from 1.10.96)	Max. Limits for 2000	Max. Limits for 2005
Sulphur ppm	500	380	50
Cetane Number	49	51 (min.)	*
Polycyclic Aromatics % weight	None	11	*
Density Kg/m^3	860	845	*

* Specification not yet set for 2005. This will be set following report by Auto Oil II programme.

Note: Certain other limits also apply but are not included above.

Meeting 2000 specifications (gasoline and diesel)

While the year 2000 will be important for refiners in terms of EU fuel specifications, it is believed that the majority of refiners have already put in place investment plans to produce fuels to meet them. Those refiners who have not already prepared for the reduction of sulphur and benzene in gasoline will now be investing in benzene and sulphur reduction technology, although by continuing to process low-sulphur North Sea crude, most refiners will be able to meet the low-sulphur levels with only modest investment costs.

In terms of overall emissions from the refinery, these changes will only give rise to a marginal increase.

Meeting 2005 specifications (gasoline and diesel)

There is no doubt that refiners will be required to invest significantly to meet the gasoline and diesel specifications for 2005.

Gasoline

The majority of UK refining installations operate a fluid catalytic cracker unit (FCCU) for upgrading heavy fractions to lighter products. The naphtha from the FCCU is the primary contributor of sulphur to the refinery gasoline pool. Reducing contribution of sulphur is the critical issue for meeting reduced gasoline sulphur specifications.

The sulphur is not evenly distributed throughout the boiling range of FCCU naphtha. Typically about half the sulphur found in the FCCU naphtha is concentrated in the final 10% of the boiling range. This gives the refiner some flexibility to minimise treatment by focusing on the heavier fraction of naphtha. The sulphur specification for 2005 is low and even when processing North Sea crude, a typical refiner will need to hydrotreat the majority of FCCU naphtha in order to meet the required level. Hydrotreatment of the FCCU naphtha reduces the olefin content which reduces octane. The impact of octane reduction on the gasoline pool needs to be considered on a refinery-specific basis.

Alternatively the refiner could hydrotreat the feed to the FCCU, in which case any further hydrotreatment may be restricted to the heavier fraction of FCCU naphtha or potentially avoided altogether. The decision to install a catalytic feed hydrotreater (CFH) of this complexity and cost will usually be made on market investment criteria since there are benefits in terms of increased conversion to higher quality products. It is not expected that a CFH will be adopted by many refiners as a method for achieving 2005 specifications.

The refiner may also utilise alternative approaches such as use of FCCU catalyst additives, blending of higher sulphur components, and extractive caustic treatment, but these are only partial solutions at best. Hydrotreatment is therefore expected to be the key approach adopted by most refiners, with associated facilities to manage the consequent octane loss from the gasoline pool perhaps being needed. Reduction in aromatics content of gasoline, also a requirement of the 2005 specification, will remove a valuable octane enhancer from the pool, further restricting the refiner's ability to manage the octane loss.

Diesel

For diesel, sulphur reduction to 2005specifications requires investment to hydrotreat the entire road diesel pool. The severity required will be determined partly by cetane and polycyclic aromatic hydrocarbon specifications. Hydrogen will be required for hydrotreatment and its sourcing will need to be addressed as noted above.

2.2.2 Bunker Fuel

Bunker fuel is used in ships' boilers for propulsion. It normally originates from the residue of atmospheric and vacuum distillation in the refinery and sulphur tends to concentrate in this product. This is one of the few markets for residues which has thus far been unaffected by environmental legislation.

The Marpol Convention (Annex 6) is currently under discussion and is being developed under the auspices of the International Maritime Organisation (IMO). This aims to control emissions of air pollutants from shipping. It proposes a global cap of 4.5% on the sulphur content of bunker oil, with a lower limit of 1.5% in especially sensitive areas. A conference took place in September 1997 which resulted in the Baltic Sea areas accepting the 1.5% limit; however, the countries bordering parts of the North Sea did not agree to the proposals. This Air Pollution Annex will form part of the Marpol Convention which, once ratified, should come into force within three to five years. The IMO will revisit the proposals if they fail to be ratified by 2002.

Indications are that countries , such as those bordering the Baltic and North Sea, may introduce domestic legislation before the Annex becomes internationally ratified.

2.2.3 Gas Oil

The sulphur content of all gas oils (except aviation kerosene) was limited to 0.2% by weight (2000 ppm) from 1st October 1994 by implementation of EC Directive 93/12/EEC.

2.2.4 Kerosene (Jet Fuel)

The European Commission is to propose a new limit value for aircraft kerosene. Details of the proposed new limit are still awaited but speculative limits suggest a sulphur limit of 100 ppm.

2.2.5 Fuel Oil

Draft EC Directive 97/0105 (SYN.) includes a proposal amending Directive 93/12/EEC which would limit the sulphur content of heavy fuel oil to 1% from 1999. The limit would not apply to fuel oil combusted in the refining industry, or in large combustion plant which is new or which already complies with the emission limits for such plant in EC Directive 88/609/EEC. The derogation for refineries and large combustion plant from this Directive is allowed on the basis that it is more cost effective to use flue gas abatement technologies to remove SO_2. (This may not be so for refineries.)

The EU acidification strategy, part of a proposed EC strategy to combat acidification of sensitive ecosystems, suggests that 9.03 million tonnes of fuel oil were utilised in the UK in 1995. Of this 3.44 million tonnes were utilised by major power producers (likely to come under Directive 88/609/EEC) and 2.32 million tonnes were used by refineries which in that year would leave 3.26 million tonnes consumed in other uses. If this proportion is reflected in future years then 36% of fuel oil used in the UK would have to be below 1% sulphur. This need to supply the low sulphur fuel oil would mean that higher sulphur fuel oil could probably be preferentially fired in the derogated refinery and power sectors.

2.3 The Future for Fuel Oil

2.3.1 The Current Fuel Oil Market and Trends

This section reviews the future markets for fuel oil. Fuel oil is a large volume product produced by refineries. It normally contains relatively high amounts of sulphur compared with other refinery products and its future large scale use is at present particularly uncertain. The product is of importance in the context of refinery emissions, as declining sales demand for fuel oil is likely to increase pressure for its use as a fuel on the refinery. An increase in the proportion of fuel oil to refinery gas combusted would see a corresponding increase in emissions of SO_2, CO_2, NOx, particulates and heavy metals.

In practice, internal refinery fuel oil consumption is set by the difference between total fuel demand and internal fuel gas supply. The fuel balance within each refinery is specific to its configuration. Other factors such as energy efficiency, electrical power import and the recovery of useful components from the fuel gas, which can contain about 50% hydrogen, will determine the final balance and hence fuel oil demand. This balance is subject to change when significant additional processing units are installed, especially those demanding fuel gas and/or hydrogen such as additional hydrotreatment.

Total European consumption of fuel oil has been falling consistently for many years as a result of structural change in the industrial sector and the competitive impact of other fuels, notably natural gas. European consumption fell from 162 million tonnes in 1982 to 107 million in 1996. By the latter year ships' bunkers accounted for about 25% of total consumption, the one sector of the market which has not been shrinking. The UK is a small market, consuming 9 million tonnes in 1995 and only 6.85 million tonnes in 1996.

Within Europe the decline has been most marked in the industrial sector with 1982 consumption of 50 million tonnes falling to less than 20 million by 1995. Power generation from fuel oil has also fallen sharply although most of this decline occurred in the 1980s. The power market is now dominated by ENEL of Italy which consumes 34% of Europe's inland fuel oil and ENEL's requirements will have a major impact on the direction of fuel oil markets in Europe over the next ten years. ENEL currently specifies a maximum of 1% sulphur for 60% of its purchases but is likely to apply the restriction to a higher percentage of its purchases in the future.

Traditionally much of the fuel oil consumed in Europe has had a higher sulphur content than this, although the sulphur percentage has been gradually declining in the face of tighter environmental legislation controlling acid gas emissions, such as the Large Combustion Plant Directive. The exception is bunker fuel but this may become subject to tighter regulations within EU coastal waters. (See Section 2.2.2.)

With regard to the quality of fuel oil used generally in the UK and its imports and exports, there is very little detailed information publicly available, but what there is would suggest the following:

(1) High sulphur fuel oil is produced to only a limited extent by UK refineries. This tends to be, for example, where heavier crudes which tend to have a high sulphur content are required for production of bitumen and lube oils. An indication of this may be seen in Table 3.1 where fuel oils with sulphur contents greater than 2% suggest some processing of non-North Sea crudes.

(2) High sulphur crudes are not processed by UK refineries to a significant extent due to the several advantages North Sea crude offers, especially its low sulphur content.

(3) Fuel oil exports from the UK are likely to be preferentially low sulphur to markets which demand this, for example, Italy. Fuel oil exports from the UK were 1 979 000 tonnes in 1996(i) (Dti, 1996) although there is no indication of the sulphur content.

(4) Fuel oil imports to UK industrial sectors other than the refinery sector are likely to be higher sulphur fuel oil, this normally being cheaper. While releases of SO_2 to air are controlled, the use of high sulphur fuel oil is not restricted in the UK, except indirectly where the process requires it or where release limits of SO_2 in any site authorisation can only be met by combusting low sulphur fuel oil. The UK fuel oil imports were 5 343 000 tonnes in 1996 (Dti, 1996) although again there are no specific data on the sulphur content of those imports. However, returns to the Environment Agency from the electricity supply industry indicate that where fuel oil is used it is often over 2.5% sulphur.

2.3.2 Future Markets

The outlook for fuel oil in Europe will be determined by both supply and demand factors, with the short term position likely to be different from the situation post-2000. In almost all cases inland demand is expected to decline slightly between now and 2000 but this will be matched by a similar drop in production as both minor and major refinery upgrades take effect. Post-2000 the situation is expected to change more radically from both a supply and demand perspective.

Demand

- In addition to the long-term gradual decline in fuel oil consumption there is the prospect of a more rapid decline post-2000 as a result of new supplies of gas becoming available in Europe at competitive prices following market deregulation. There is no clear forecast available, but it is conceivable that the inland market for fuel oil could decline by 50% beyond 2005 while bunker fuels remain static. If this happens, European consumption in 2005 would be around 65 million tonnes.

- Trends in product quality are more important than the volume of demand. It seems highly likely that industrial or power users will either have to invest more widely in flue gas desulphurisation or be restricted to buying fuel oil with 1% or less of sulphur. It is unclear how far legislation will tighten for ships' bunker fuels, but any plan to tighten quality in bunker fuel will put further pressure on the high sulphur product. The scope for using fuel oil as a 'sink' for sulphur will be greatly restricted.

- With declining markets at home, European refiners will be looking for other outlets for their fuel oil. One potential market is Asia which is deficient in fuel oil despite recent increases in refinery capacity. Net imports to that region were expected to be around 4 million tonnes in 1997, rising to almost 20 million in 2000. Imports are then forecast to decline to around 16 million in 2005 although this assumes that a significant amount of new local production capacity is built. Not all of this market is available to European suppliers since Asia is a well established market for Middle East refiners and supplies also come in from the West Coast of the USA. It does, however, provide an outlet for some of Europe's potential surplus, although it should be noted that many Asian countries have introduced or are introducing increasingly stringent environmental legislation which may also require the firing of low sulphur fuel oil.

Supply

- Over the next three to four years fuel oil output from European refineries is likely to decline slightly, probably in line with falling demand. The situation may change more radically in the early years of the next century as refiners come to terms with much more stringent quality standards.

- European refiners may benefit from a reduction in fuel oil exports from the Former Soviet Union (FSU) which currently total about 20 million tonnes per year into Western Europe. Over the next ten years refinery closures and upgrading projects will reduce the availability of fuel oil from that region. This may reduce the potential surplus in Europe but it will have no impact on the trend to cleaner fuel oil.

2.3.3 Implications for UK Refineries

UK refineries have consistently produced an exportable surplus of fuel oil. In 1997 production was 11.7 million tonnes, compared with consumption of only 3.9 million tonnes. Both domestic and European markets are expected to continue a gradual decline over the next ten years which will put pressure on refiners to either upgrade or find new export markets. The reduction of high sulphur fuel oil within Europe is expected to be more rapid for land-based markets, leaving a supply market for fuel oil to ships' bunkers only which would total about 25 million tonnes. Export markets outside Europe are moving the same way, although at a slower pace, and 3.5% sulphur product will still be permitted in some countries for a while. Countries such as Thailand have already introduced legislation to prohibit the burning of high sulphur fuel oil (HSFO) in the greater Bangkok area and this trend will gradually extend to other countries in the region.

Overall, therefore, UK refiners will have to manage a gradual change in their fuel oil business as markets decline and quality standards improve. It will be gradual, however, and no precipitative change is anticipated.

2.4 UK Refinery Capacity and Economics

The following section reviews recent trends and performance in the capacity and economics of the UK refinery sector.

This assessment has been restricted to the refinery industry sector. It has not considered the broader economic base of the refining companies which often own integrated chemical complexes, usually located on the same site as their refinery; nor has it considered the interests and ownership the companies often have in oil production facilities in the North Sea and world-wide.

2.4.1 Current UK Refinery Capacity

Total UK refinery capacity reduced significantly in the early 1980s in response to falling demand and poor margins. Total distillation capacity fell from about 130 million tonnes in 1980 to a little over 90 million tonnes by 1985, a level broadly maintained since then.

Utilisation rates were very low in the early 1980s even with capacity being closed. In 1983, for example, the output of all products was only 70% of installed distillation capacity. Sales to the UK market were even lower and surplus product had to be exported. Since then utilisation levels have risen steadily as Figure 2.7 illustrates.

In 1996 the utilisation level across the UK refinery sector was at least 92% with approximately 13% of production being exported.

The Gulf Refinery at Milford Haven has now been closed which removes about 5 million tonnes of capacity from the UK total (approximately 5% reduction) and plans are being made to close the Shell Refinery at Shell Haven and part of the Llandarcy Refinery.

2.4.2 Future Capacity

The increase in UK refinery utilisation levels which has occurred since 1980 has been due almost entirely to capacity closures and a modest increase in exports. Domestic demand for all products has been almost static, having risen from 71 million tonnes in 1980 to 75 million tonnes in 1996, an increase of only 5.6% after 16 years.

There is no reason to think that demand will grow significantly between now and 2005. Demand for transport fuels will be restrained by high taxation levels and the possible impact of government policy on levels of car use as well as improvements in fuel efficiency. The UK consumption of fuel oil and gas oil for heating is likely to continue to fall in the face of competition from gas. On this basis UK refiners will continue to operate in a near-static domestic market and will look to export markets to take 'surplus' product.

Over the past two years UK and other European refiners have been able to take advantage of buoyant US demand for gasoline. Total gasoline exports in 1996 were over 8 million tonnes.

Currently there is a gradual shift in transport fuels from gasoline to diesel. If this slow shift continues UK refiners will continue to look to the USA for gasoline exports. The long-term outlook for these exports is unclear, being dependent, in part, on refinery capacity increases in the USA and Latin America.

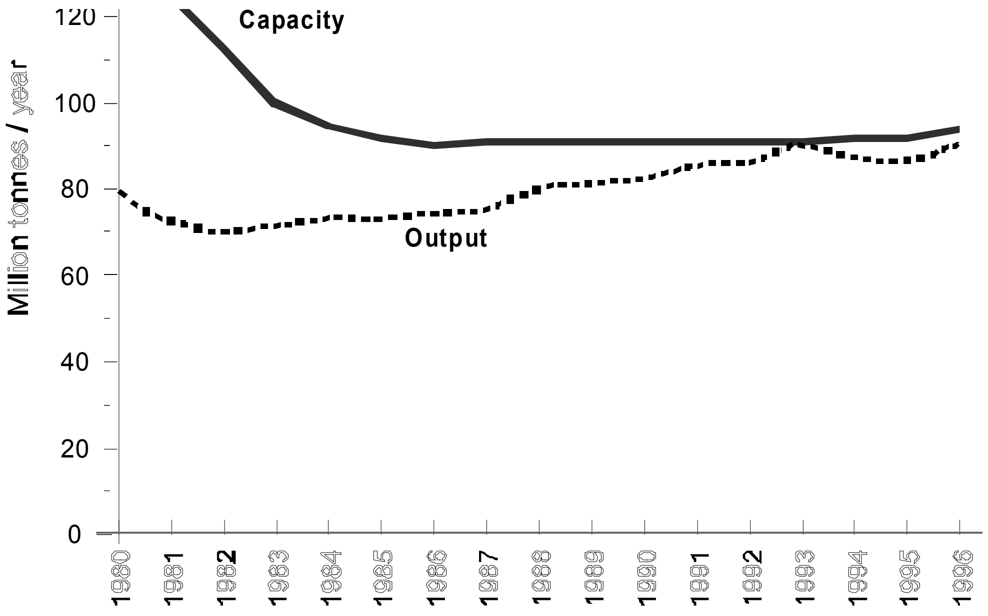

Figure 2.7 UK refinery capacity utilisation

Given that UK and European demand will be fairly static, the key factor will be supply. There is likely to be very little European demand for new refineries or large capacity increases between now and 2005 although developments on the margin of Western Europe, such as at Leuna, former East Germany, and Midor in Egypt, could have a major impact. There will continue to be capacity creep, due to the occasional upgrade which will tend to increase capacity on a modest scale.

With the above factors the importance of refinery closures becomes apparent. There has been much talk of closure in recent years and some refineries have been shut down. Given the financial problems of the industry more closures may be expected but timing is very uncertain. It could well be the case that the process will accelerate post-2000 as refiners contemplate heavy capital expenditure to meet 2005 product specifications. The extent to which UK refiners are affected by closure is impossible to predict. There is no doubt that overall market conditions will put pressure on the refinery sector to reduce capacity but it may need a specific trigger such as 2005 specifications to overcome the inertia in the system caused by high site clean-up costs, employment protection agreements, etc.

2.4.3 UK Refinery Economics: Outlook to 2005

Refinery margins in Western Europe have been poor for many years but the situation worsened from mid-1994 in the face of adverse global trends. Much investment at refineries in the late-1980s/early-1990s had been based on the assumption that the average barrel of feedstock would become heavier and sourer. By 1994 this assumption had been undermined by an increase in supply of light, low sulphur crude from the North Sea, Africa and, most unexpectedly, Saudi Arabia. The result was that upgrading margins were badly squeezed and overall profitability declined even further.

Figure 2.8, published by UKPIA, shows the steep decline in operating profitability in the downstream sector of the UK oil industry. It should be noted that the downstream sector includes both oil refining as well as product distribution and retailing. By 1996 there was an overall operating loss and while there was some improvement in 1997 it was not dramatic. The situation is broadly similar throughout Western Europe. In a recent presentation Rolf Stomberg of BP estimated that there is approximately 500 000 barrels per day of surplus refinery capacity in the region. The extent to which this surplus is eliminated is a key determinant of whether the industry can become consistently profitable again.

Although demand for refinery products is fairly static in overall terms, the market for particular products is expected to change significantly over the next ten years. The gradual reduction in fuel oil sales will increasingly concentrate demand on transportation fuels and petrochemical feedstocks. Product quality standards for 2005 are well beyond the ability of most UK refineries to produce with their existing

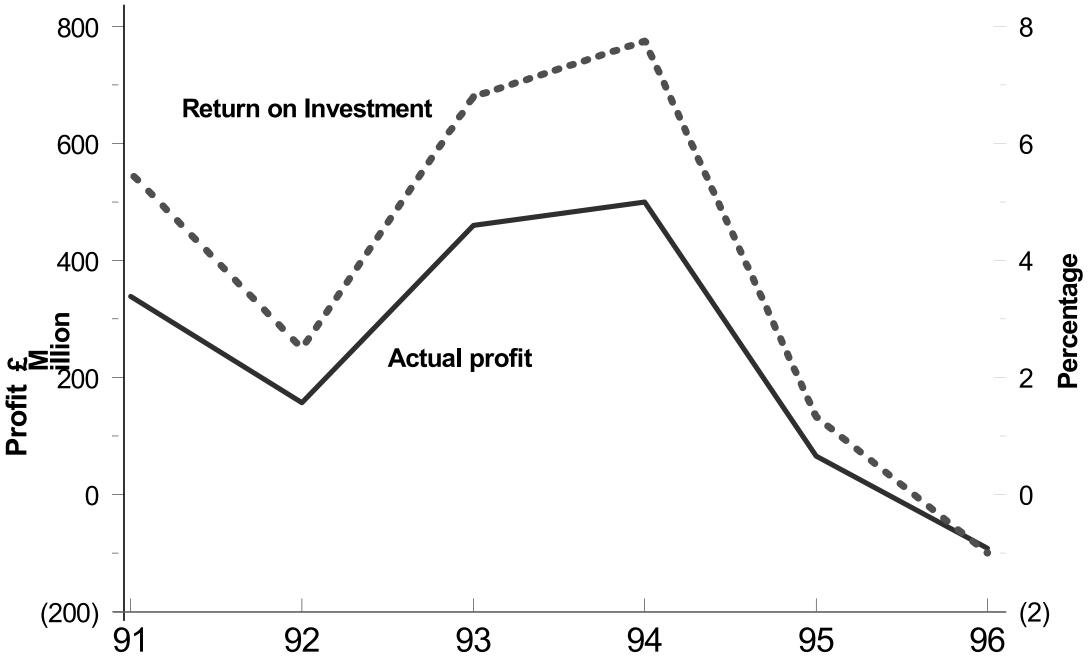

Figure 2.8 UK refinery sector profitability (Source UKPIA)

plant and equipment even when processing 100% North Sea crude. These factors will combine to put pressure on refiners by the early years of the new century and a point will be reached when decisions will have to be made to upgrade or close down refineries.

These comments assume that the European refining industry remains only marginally profitable as it has been for several years. In the 1990s poor economic performance was due in part to very poor utilisation levels caused by an excess capacity. Since then much of this has been eliminated and European refineries are now running at much higher levels - at least 92% on average in 1997.

Under these circumstances it might be assumed that profitability would have shown a marked improvement. In reality, however, most refiners experienced only a modest improvement in margins during 1997 to 1998, which was mainly concentrated in upgrading margins, due to highly competitive conditions at the point of sales.

Individual refiners have a tendency to process as much throughput as possible, since this improves revenue, but it is based on marginal costing. As long as the plant is amortised and requires little additional expenditure, this situation is sustainable.

The key issue for the future will be the recently-introduced legislation on fuels quality which will compel most refiners to invest heavily. At this point margins must rise to a level which enables new investment to be financed. If this is not forthcoming the rational market response would be a wave of refinery closures to create a much tighter market, thereby improving margins. In the period up to 2005 it is expected margins will improve slightly but remain low relative to other industries.

2.4.4 Likely Investment Patterns to 2005

In the present economic climate for refineries, operators/owners are expressing extreme reluctance to invest in new plant, including abatement plant, for the following reasons:

- with intense forecourt competition any added product value resulting from investment will almost immediately be lost;

- investment for environmental purposes provides no added product value and overall has a marginally negative value on return on capital employed (ROCE);

- some future environment specifications, e.g. the EU Acidification Strategy, are not firm. Refiners want clear targets in view of the high level of capital expenditure likely to be involved;

- the UK is now having to compete to some extent with countries who have already invested more heavily in environmental plant (i.e. sunk cost).

Although investment made by refiners in existing plant in the immediate future will be the minimum necessary, they will need to consider strategic options for their refinery operation and prospective major plant investment in the years 2001 to 2002 in the run up to 2005. It is at this time that one might expect refiners to give consideration to strategic investment in ‘bottom of the barrel conversion processes’ such as coking, gasification, solvent deasphalting, residue catalytic cracking and residue hydroprocessing. This period of major investment would be an opportune time for refiners to consider their long-term strategy for processing either heavy/sour or light/sweet crudes. The investment option selected will be site-specific and will take account of the owner's strategic objective with respect to refinery configuration, crude supply and product markets. Therefore in the short term, before the year 2005, abatement options will normally be considered in respect of existing plant only.

2.5 Discussions with Operators

2.5.1 Topics of Discussion

During September and October 1997 discussions were held with representatives from all eleven UK refineries including Gulf which has since announced closure plans. In addition a meeting was held with the UK Petroleum Industries Association (UKPIA). The association represents refinery operators in the UK. The items which formed the initial basis for each discussion included the following. (These were forwarded to each refinery in advance of each discussion.)

(1) Does the refinery operate an environmental management system (EMS) or does it intend to do so?

(2) What does the refinery regard as its main environmental issues? How have these been identified and are there plans to further address them?

(3) Does the refinery have an ongoing programme of waste and energy minimisation? Have any economic benefits been gained, and reduction of releases to the environment been made, through the adoption of such measures?

(4) Has any work been done on identifying sources of fugitive emissions of volatile organic compounds and have these been aggregated to give an annual estimate? Does the refinery have a programme in place for reduction of these types of release?

(5) In your opinion is the IPC (Integrated Pollution Control) process and the way it operates effective in achieving improvements in environmental performance? If not, what changes might be made?

(6) How does the refinery see the future up to 2005 and, to a lesser extent, beyond, with regard to changes in crudes to be processed, tighter product specifications especially with regard to sulphur content, and continued reduction in allowable releases to the environment?

(7) What is the general view of refinery economics up to 2005 and beyond?

(8) With regard to reduction in releases to the environment, do you see improvements in existing abatement equipment and techniques such as BATNEEC (Best Available Techniques Not Entailing Excessive Cost) or possibly more radical approaches being needed?

(9) Any other points.

Notes of each discussion were written by, and forwarded to, the operator as a record. The discussions often went wider than the above eight items and the operators’ general responses set out below reflect this.

2.5.2 The Operators’ Responses

The main points that most of the operators had in common or emphasised are as follows.

(a) North Sea crude oil supplies

All refiners broadly concurred that supplies of sweet North Sea crude oil will be available up to 2005 and probably well beyond. However, a few sources of North Sea crude are becoming more acidic and therefore pose potential corrosion problems in certain refineries.

(b) Auto oil 2000 specifications

Most refineries will be able to meet the specification for the sulphur in gasoline and diesel, and other specification changes for the year 2000, with only minor modifications to their operating plant providing they continue to process low sulphur crudes.

(c) Auto oil 2005 specifications

Refiners generally agree that to achieve the limits of sulphur in gasoline and diesel and other specification changes required by the EU for 2005, they will need significant refinery investment, principally in new hydrotreatment facilities.

(d) Refinery utilisation and margins

Refiners confirm that, compared with the 1980s and early 1990s, refinery utilisation is now much improved (above 90% of design throughput) and generally this upward trend is expected to continue, albeit slowly. Some refiners are optimistic that profit margins could improve in the foreseeable future, from what is currently an extremely low if not a negative level in some cases.

(e) Refinery investment

Mainly due to very low financial margins, most refiners have no plans for significant investment in the near future. They maintain that, due to the intense competition at retail outlets, the added margins that might be gained from an improved product resulting from extra investment would very quickly disappear. In addition, in the current economic climate, a fairly common view is that the money spent on environmental improvement provides little or no financial benefit. It increases the investment in fixed assets but since it gives no return it reduces the return on capital employed. The refiners also make the point that due to the considerable costs normally associated with abatement plant it is essential that clear and unchanging targets and limits are specified for the coming years. Refiners indicate that currently many of these limits are neither clear nor fixed.

(f) Fuel oil

There was a general consensus that sale/disposal of fuel and residue oil will become increasingly difficult in the future as demand for this type of refinery product falls. Those refiners able to offer low-sulphur fuel oil will be able to market their product more easily. As a result some refiners indicated that they may wish to burn more fuel oil on the refinery in the future.

(g) Local air and water quality

A number of refiners expressed the view that where there is no evidence that EU, National or local air and water quality targets were being breached due to releases from their refinery, then there was little justification for further high-cost abatement plant to be installed.

In this respect they emphasised that any additional abatement needs to be justified on the basis of ‘sound science’ in respect of the need to improve local environmental quality and the improvement effect it may have. An example quoted is the proposed Expert Panel on Air Quality Standards (EPAQS) for SO_2 which refiners believe is lacking a basis for the size of the safety factor between the lowest observed human effect level and the actual standard chosen. Refiners also emphasised that the effects of abatement improvements recently made and how ecosystems are recovering should be considered before further legislation is imposed. Some refiners felt in this connection that a gap exists between those who propose and enact environmental legislation and the needs for it, with its resulting costs.

(h) IPC and Integrated Pollution Prevention and Control (IPPC)

The consensus was that the IPC system as a whole was working satisfactorily and was achieving improved environmental performance. Refiners believe it lays down an understandable framework and that the communications that are necessary with the site inspector are welcomed.

Some concerns were expressed about how IPPC might impact on the current IPC system. The terminology in each case needs to be clear. In particular, refiners are concerned about the requirement of IPPC for existing plant to meet the requirements of new plant in 2007. (See also item (i) below.)

(i) BATNEEC for new and existing plant

Regarding what constitutes BATNEEC; on the whole refiners do not think that existing plant performance should move towards the standards set for new plant. They see the way ahead for refineries as that which has currently been agreed with local inspectors on improvement plans for each refinery.

(j) ‘Level playing field’ with rest of Europe

Refiners pointed out that the UK environmental regime needs to keep in step with the rest of Europe. Notwithstanding this there is no indication that the current regulations are putting UK refiners at a significant economic disadvantage compared with the rest of Europe.

(k) Consistent application of existing regulations

Some refiners felt that the application of the existing regulations as applied by the Environment Agency varied significantly from refinery to refinery and that therefore some refiners were not being asked to achieve the same environmental levels of abatement as others.

(l) Reporting requirements

There is general support for the ‘bubble approach’ for refinery authorisation with less prescriptive limits at point sources of release. In a few cases, mainly in respect of effluent discharges, the reporting requirements for release points was viewed as excessive.

(m) Inter- and intra-company co-operation

With no major improvement in refinery margins expected in the near future, refiners are continuing to look at possible co-operative arrangements with other refiners and at possibly networking products and feedstocks within their North West Europe refinery operations. There is a general concern that a few refineries, particularly the smaller ones, could be subject to closure considerations.

2.6 Legislation for Releases to Air

2.6.1 The System of Control of Environmental Impact of Refineries in the UK

Releases of pollutants to air, water and land from refineries are regulated in the UK through the system of Integrated Pollution Control (IPC) introduced by Part I of the Environmental Protection Act 1990. The legislation aims to provide a dynamic system of regulation which can respond to improvements in industry practice in the field of pollution control by requiring industry to apply the BATNEEC to control emissions to air, land and water. It is an integrated system in that it requires the use of the control measures which offer best practical environmental option (BPEO) to ensure that the control of emissions to one environmental medium is not to the detriment of the others. The system is site-specific in order that the specific operational and environmental conditions at a site can be taken into account. IPC is enforced by the Environment Agency and the system of site authorisations and regular reporting ensures that IPC is applied. Reported releases by a site are included in a Public Register maintained by the Environment Agency. IPC authorisations are also the means by which international commitments as they apply to refineries are implemented. These commitments and likely future ones are described below.

2.6.2 International /European Commitments

Integrated Pollution Prevention and Control (IPPC) Directive 96/61/EEC

This framework directive was adopted by the EU in September 1996, and will require the application of best available techniques (BAT) as defined in this directive. This should be adapted to local circumstances taking into account contribution to transboundary air pollution. Existing installations should comply with the Directive by the year 2007, and new installations from 1999.

Large Combustion Plant Directive (LCPD) 88/609/EEC

In general terms this existing Directive sets reduction levels for SO_2 , NOx and particulates for new and existing plant licensed prior to 1987. Large combustion plant (LCP) are those with a net rated input greater than 50 MW thermal (th). The directive excludes FCCUs and gas turbines.

Emission reduction targets for existing plant based on 1980 emissions are presented in Table 2.4.

Table 2.4 Emission reduction targets of the LCPD

1980 Base	1993	1998	2003
SO_2	20%	40%	60%
NOx	15%	30%	

A meeting of experts from EU member states to discuss the revision of the LCPD (88/609/EEC) in May 1997 has resulted in a proposal for a new directive, entitled the Large Combustion Installation Directive.

The Proposed Large Combustion Installation Directive (LCID)

The requirements for new National Emission Ceilings of acid gases in this proposed new Directive have been assessed on the basis of 'critical loads'. The critical loads assessment, in the case for acid gases, appraises the environmental receiving capacity of, for example, types of ecosystem, below which no significant harmful effects to sensitive elements of the environment would occur. Article 3 of the draft Directive states that by 1 July 2002, the member states shall draw up programmes for the progressive reduction of total annual emissions of SO_2 and NOx into the air from existing and new combustion installations, to comply with emission ceilings assessed on the basis of critical loads. The Large Combustion Installation Directive will encompass plant within the existing LCPD but will also include gas turbines and, on refineries, combustion plant larger than 3 MW(th).

The 2010 emission ceilings assessed for the UK are presented in Table 2.5, together with both the emissions of large combustion plant in 1996 (excluding gas turbines) and the minimum percentage reduction represented by the 2010 emission ceilings. It is assumed that the refineries will be required to contribute similar percentage reductions of SO_2 and NOx. Since 1994 the Gulf and Llandarcy refineries have closed and the Shell Haven Refinery is planned to close about 2000.

The effect of these closures is to reduce the percentage reductions required of the remaining refineries. This information is also shown on Table 2.5.

Table 2.5 Emission Reduction Requirement of the Proposed Revision to the LCPD

Pollu-tant	EC emission ceiling inc. gas turbines	1996 UK LCP emissions exc. gas turbines	% Reduction required as a minimum by 2010	% Refinery sector reductions following known refinery closures
SO_2	75 kt/y by 2010	1 468	95%	94%
NOx	60 kt/y by 2010	471	87%	85%

Paragraph 5 of Article 3 of the proposed LCID states that Member States shall establish, starting in 2002 and for each subsequent year, a complete emission inventory for existing and new installations covering SO_2 and NOx:

- on a plant-by-plant basis for plant combustions above 300 MW(th) and for refineries;
- on an overall basis for other combustion installations to which the Directive applies.

Postscript

The LCID is now not likely to apply to existing large combustion plant.

The United Nations Economic Commission for Europe (UNECE) Second Sulphur Protocol (1994)

This protocol has also been produced using critical loads assessments. Countries are required to reduce, by the year 2000, their sulphur emissions to meet a UNECE-wide target of 60% of the gap between sulphur emissions and the critical load. Particularly sensitive areas of Scandinavia, Germany and the Netherlands, where natural and unattributable emissions exceed the critical load, have been excluded. The target reductions for individual countries are based on their contribution to acid deposition over the areas included in the calculations. To meet the UNECE- wide target of 60%, the UK has agreed to reduce its own SO_2 emissions on a 1980 basis as presented in Table 2.6.

Table 2.6 Emission reduction requirements of the second sulphur protocol

	2000	2005	2010
SO_2 emission reduction (1980 base)	50%	70%	80%

The new protocol was officially signed in Oslo in June 1994; however, it has yet to be ratified by the 16 signatory countries. Examination of the atmospheric emission Inventory for the UK indicates SO_2 emissions have reduced from 4903 kt in 1980 to 2718 kt in 1994, a reduction of 55% and compliant with the protocols demand for 2000.

EU Communication on Acidification Strategy for Europe

Proposals for an acidification strategy have been presented by the European Commission in the form of a communication: ‘A European Union Strategy to Combat Acidification’ (March 1997). The acidification strategy is intended to be complementary to the proposed LCID. It has been developed in co-operation with the UNECE Convention on Long Range Transboundary Air Pollution (UNECE/CLRTAP) which is also at the early stages of developing a multi-pollutant reduction strategy with a wide geographic spread. The aim of the strategy is to reduce emissions of the three principal pollutants responsible for acidification, i.e. SO_2 and NOx from combustion processes and ammonia from farming and agricultural activities. Implementation of the strategy (together with other efforts) would result in an EU-wide reduction of 66%, 48% and 15% for SO_2, NOx and ammonia (NH_3) respectively in 2010. The Commission acknowledges this as being a significant challenge. Published data show that in 1990 the UK was the second highest contributor of SO_2, NOx and (NH_3) in the EU providing around 23% (SO_2), 20% (NOx) and 9% (NH_3).

The strategy adopts the same ‘critical loads’ approach used by the 1994 Sulphur Protocol and the proposed LCID.

The strategy has considered a wide range of policy initiatives to attain, by 2010, a 50% closure of the gap between present emission levels and the levels that represent critical loads. In developing these policies the EU has considered environmental and economic costs and benefits. The policy of greatest relevance to refineries is the development of national emission ceilings. Although acknowledged as requiring further development, provisional ceilings are annexed to the communication. The proposed ceiling levels for the UK to achieve by 2010 for SO_2, NOx and NH_3 are given below in

Table 2.7. The data are also shown in terms of percentage reduction required with 1994 as the base year (Salway AG et al (1996)). The figures in the current version of the draft document are only indicative and it is likely there will be considerable resistance to these tough demands.

As with the LCID, it is assumed refineries would be required to make corresponding percentage reductions. These are also shown after allowing for known refinery closures.

Table 2.7 UK Emission reduction requirements of the acidification strategy

	SO_2	NOx	NH_3
UK emission limits by 2010	279 kt/y	753 kt/y	224 kt/y
% reduction required (1994 base year)	90%	67%	30%
% refinery reduction required following closures of Gulf, Llandarcy and Shell Haven refineries	89%	63%	

Postscript

The EU is now likely to reflect the aims of the Acidification Strategy in a new National Emission Ceilings Directive design to be met by 2010. The possible UK emission limits, as of early 1999, are increased to 497 kt/y for SO_2 and 1181 kt/y for NOx.

The International Climate Change Convention

This convention was initiated at Rio de Janeiro in 1992 where countries committed themselves to reduce their greenhouse gas emissions to 1990 levels by 2000. These gases are chiefly CO_2, methane (CH_4), and nitrous oxide (N_2O). The parties to the convention met in Kyoto, Japan, in December 1997 and agreed on targets beyond 2000.

Volatile Organic Compounds (VOCs) Protocol

Within a refinery, crude oil receipt, refining and product loading are significant sources of VOCs. The protocol obliges most parties to secure a 30% overall reduction in their VOC emissions by 1999 using 1988 as a baseline.

2.7 Legislation for Releases to Water and Land

2.7.1 Releases to Water

As outlined above releases to water from refineries are regulated in the UK through the system of Integrated Pollution Control (IPC). As a result of the Water Resources Act, 1991 (in Scotland the Control of Pollution Act, 1974) and the Environment Act, 1995, water pollution control in England and Wales is enforced by the Environment Agency. In Scotland this responsibility falls to the Scottish Environment Protection Agency (SEPA). Most countries in the world have a system of fixed discharge limits. In the UK discharge limits for flowrates and concentration are set based on the water quality and usage of the receiving body of water. The limits are generally set on a 95 percentile basis. This means that at least 95% of results obtained by sampling must comply with the limit. An additional limit for the instantaneous maximum is also given.

The EC Directives on water quality are incorporated into the consent levels once they are embodied into UK law. Recent EC Directives have been introduced on Dangerous Substances, Bathing Water, Freshwater Fisheries, Nitrates, and Urban Waste Water Treatment.

In the longer term, discharge to rivers limits will be set based on statutory water quality objectives (SWQOs), which will be used to set quality planning targets, and the general quality assessment classification (GQA), which is used for periodic assessments of river quality. Future limits on discharge levels to certain rivers will also be set using a toxicity-based approach.

2.7.2 Releases to Land and Contaminated Land

Solid wastes

Refineries generate two types of solid waste streams: industrial and non-industrial. It is estimated that approximately 3kg to 5 kg of solid waste is generated per tonne of crude oil processed. About 80% of this has a significant heavy metal content (Pollution Prevention and Abatement Handbook (1997))and could potentially be considered as hazardous.

Waste disposal is subject to legislation and refiners are currently obliged to comply with the following:

- Collection and Disposal of Waste Regulations (1988);
- Control of Pollution Act (1974);
- Duty of Care: Section 34 Environmental Protection Act (1990);
- Definition of Waste: Section 75 of Environmental Protection Act (1990);
- Controlled Waste Regulations (1992);
- Waste Management Licensing Regulations (1994);
- Special Waste Regulations (1996).

Future waste management legislation

Forthcoming EU legislation on the landfilling of wastes is likely to have some affect on UK refineries. The draft Landfill Directive (Com (96) 647) was presented by the Commission in February 1997 and has several aims including a requirement to ensure that all waste going to landfill has been subjected to some form of treatment. Other issues such as the prevention of hazardous and non-hazardous wastes being co-disposed and the pricing of landfill to cover setting-up, operation, closure and aftercare costs of the site, are also addressed by the draft directive. Implementation of the directive is likely to result in higher costs for all generators of industrial/commercial waste. A number of UK refineries have dedicated landfill facilities and these will be subject to the new requirements. These requirements will include the need for engineered containment facilities and will therefore result in increased disposal costs.

Contaminated land

Pollutants released to the ground via accidental spillages or leakage during storage, transfer or utilisation, may be a potential land contamination issue for refiners. If refinery closure and subsequent sale of land is contemplated and there is evidence of land contamination, including pollution of the underlying groundwater system, then some degree of land remediation programme by the operators is likely to be required.

Under Draft Guidance on Contaminated Land (Consultation, September 1996) particular sites that have been identified by the local authority as being contaminated may also acquire a *Special Site* status by virtue of petroleum operations being, or having been, conducted on such sites. In such instances, a *Remediation Notice* may be served on the owner of the land and be enforced by an ‘appropriate authority’ which is likely to be the Environment Agency. Considering the long established histories of refineries in the UK, such regulations are likely to require refiners to set aside significant monies for land remediation if they are contemplating total refinery closure.

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3. UK REFINERIES

3.1 Types of UK Refinery

3.1.1 Description of Refinery Types

Crude oil refineries vary in their complexity and the products manufactured. Complex refineries make use of conversion processes such as catalytic cracking, coking and hydrocracking in order to produce higher-value products at the expense of lower-value ones. This requires substantial extra energy input so that releases from a complex refinery are greater in total than a refinery of similar capacity but lacking the complex conversion processes. To facilitate discussion about oil refineries a broad categorisation is often applied which is based on the process units utilised on the refinery. These categorisations are explained as follows.

(a) Hydroskimming refineries

This simple refinery type has only an atmospheric crude distillation unit (CDU) and processes for the production of gasoline, kerosene and gas oil (used as automotive diesel fuel or heating oil). A simplified hydroskimming configuration is shown in Figure 3.1. Lighter components are either burned on the refinery as fuel or recovered as LPG (propane and butane). The principal motor gasoline component (reformate) is made by hydrotreating naphtha from the CDU and then raising its octane in a catalytic reforming process. The catalytic reformer raises the octane number of the feedstock by changing its chemical composition. This includes the production of more aromatic (ring based) compounds. In this process hydrogen as a by-product is produced. The hydrogen is used in the hydrotreater process to remove sulphur, with any excess normally routed to fuel gas. Residue from the CDU (atmospheric residue) is used as fuel oil. Due to its high fuel oil yield and the low value of this product this type of refinery tends to be less economic when refining margins are weak. Nonetheless, of all the refineries in the world approximately 40% are of the hydroskimming type. In the UK, the Phillips Imperial Petroleum Refinery is an example of a hydroskimming refinery.

(b) Cracking or lube oil refineries

Here the hydroskimming refinery is further developed by the addition of a vacuum distillation unit (VDU) producing vacuum gas oil (VGO) and vacuum residue. VGO, called ‘wax distillate’ by some refiners because of the waxy nature of the material, can be catalytically broken down into lighter products (cracking) or used as base oil for production of lubricants. It can also be used as ethylene cracker feedstock for chemicals manufacture. Two principal catalytic processes are available for VGO cracking, namely fluid catalytic cracking (FCC) and hydrocracking.

Figure 3.2 shows a simplified Flow Scheme for a Cracking Refinery with an Fluidised Catalytic Cracking Unit (FCCU).

Fluid catalytic cracking (FCC) has been continually developed since its introduction to the refining industry in the 1940s. The core of this process consists of two large vessels. One is the reactor where the longer-chain hydrocarbons are broken down with the application of a catalyst under very turbulent conditions. The other vessel is the regenerator where the accumulated carbon on the catalyst is burnt off, again under very turbulent conditions. The catalyst circulates continuously between the reactor and regenerator, but it is the regenerator from where the emissions to air occur on an FCCU. The modern process uses a zeolitic catalyst which is continuously regenerated to remove unwanted coke deposits. The FCCU's major product is normally gasoline, yielding approximately four times more gasoline than middle distillate (kerosene, gas oil). In addition, the process produces light olefinic material (C_5 minus) which can be used to produce more gasoline in processes such as alkylation, etherification and polymerisation.

Hydrocracking is a process in which longer-chain hydrocarbons are broken down catalytically under a high hydrogen pressure (typically 80-150 bar). In contrast to the FCCU, the products of hydrocracking are normally predominantly middle distillates, suitable for diesel production, although gasoline production can be achieved by appropriate selection of catalyst and operating conditions. A major advantage of hydrocracking, compared with FCC, is that products are high quality in relation to contaminants, requiring little, if any, further processing and containing essentially zero sulphur. However, the octane number of hydrocracker naphtha is too low and this is routed to the catalytic reformer for octane improvement. The catalytic reformer, the main source of hydrogen on a refinery, cannot usually meet hydrogen requirements on a hydrocracking refinery and a hydrogen production plant is usually required in which hydrogen is produced, usually by reforming natural gas.

Lube oil: in a lubricating-oil-producing refinery a range of lube base oils are produced from side streams off the VDU for subsequent blending to finished oils. A number of hydroprocessing and/or solvent extraction processes are employed to raise the paraffinity of the base oil. In most lubricating oil refineries valuable wax by-product is produced.

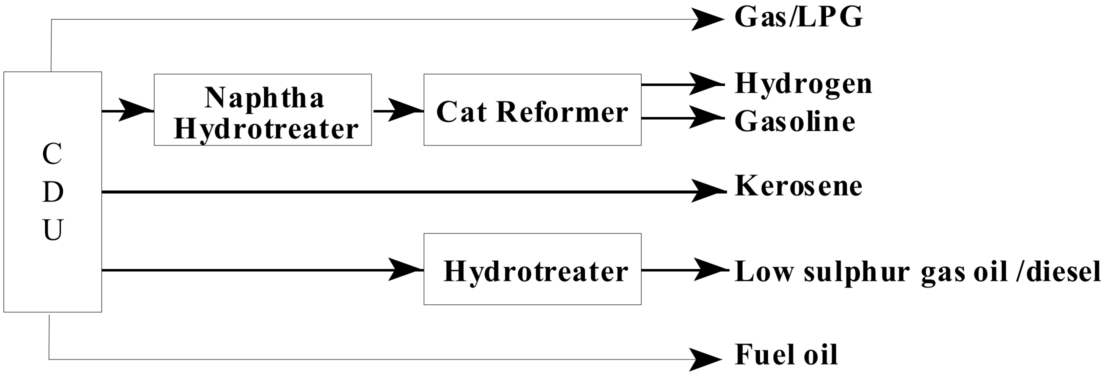


Figure 3.1 Simplified flow scheme of a typical hydroskimming refinery

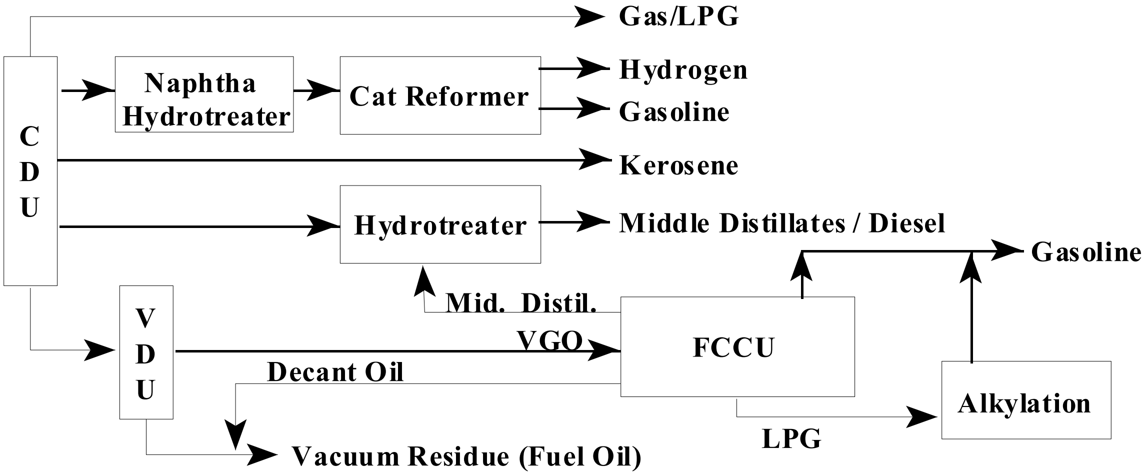


Figure 3.2 Simplified flow scheme of a typical cracking refinery

The vacuum residue, the bottom stream from the vacuum unit, from this type of refinery usually goes to fuel oil, but some refiners also produce bitumen from this stream.

With the exception of Phillips Imperial Petroleum and Shell Haven all UK refineries have an FCCU. BP Oil Grangemouth has both FCC and hydrocracking. Shell Haven has a hydrocracker.

(c) Residue upgrade refineries

In this type of refinery the heavy residual materials (e.g. vacuum residue) are upgraded or destroyed as shown in Figure 3.3. Various technologies exist which allow the refinery to produce zero fuel oil, but these are of high capital cost. In today's economic environment, especially in the UK refining sector, these technologies are unlikely to provide the return on the capital investment involved.

The most common residue upgrading processes world-wide are delayed coking (especially favoured in the USA) and residue hydroprocessing. Delayed coking, as practised at the Conoco Refinery in the UK, produces transportation fuels (approximately 60% by weight of the feed) and a petroleum coke which is of premium anode grade quality. Currently it is the only refinery in the UK with a coking unit.

Residue hydroprocessing can be applied to atmospheric residue, vacuum residue or a blend of both residues. The processing objective is to raise the quality from high sulphur fuel oil to low sulphur fuel oil (not usually economic) or to pretreat the residue ahead of further processing (usually catalytic cracking). Lower-cost processes for residue upgrading are available, such as visbreaking and solvent deasphalting, but the amount of upgrading achievable is limited, especially on poor-quality crude.

Three UK refineries (Conoco, Esso Fawley and Shell Stanlow) have significant residue upgrading plant.

3.1.2 The UK Refineries

In terms of the above the ten UK crude oil refineries analysed in this review can be classified as follows:

Hydroskimming	- Phillips Imperial Petroleum
Cracking and/or Lube	- BP Grangemouth - Elf Milford Haven - Lindsey Oil - BP Coryton - Shell Haven - Texaco Pembroke
Residues Upgraded	- Conoco - Esso Fawley - Shell Stanlow

A brief description of each UK refinery is provided in Appendix 1.

3.2 Sources of Polluting Emissions on Refineries

3.2.1 Refinery Processing with Respect to Releases to Air

The following paragraphs briefly discuss releases and the sources of releases in relation to current UK refinery processing practice.

(a) Refinery process heaters and boilers (combustion processes)

Sulphur dioxide (SO_2), nitrogen oxides (NOx) and particulates are the usual pollutants released to air from refinery process heaters, boilers and other power plant. This plant is often designed for dual firing of gas and oil and therefore the emissions released are dependent upon the type and balance of fuels burned in the process. Refinery fuel gas and fuel oil are the usual fuels. Most refineries use either atmospheric residue or vacuum residue as fuel oil but visbreaker residue is also used in a few cases. Refinery fuel gas is normally the base fuel and used to its fullest availability, with shortfalls in refinery fuel gas supply made up by burning fuel oil or occasionally vaporising propane. Refinery fuel gas is normally much lower in sulphur than fuel oil and typically contains about 50% hydrogen. Typically, refineries in the UK are burning refinery fuel gas with a sulphur content, as H_2S, ranging from 0.05 to 0.6 vol%, and fuel oil with a sulphur content of 0.8 to 4.5% by weight. Hence the amount of SO_2 that is emitted from combustion processes on a refinery is heavily dependent on the fuel gas/oil ratio.

NOx, a mixture of nitrogen oxide (NO) and nitrogen dioxide (NO_2), is produced during combustion from the combination of oxygen and nitrogen in the air and by the combination at high temperature of oxygen in the air and nitrogen in the fuel. Unlike fuel oil, natural gas and refinery gas contain no nitrogen compounds.

There are several methods for the reduction of NOx, the most usual being the installation of low NOx burners. Most refineries in the UK have implemented, or are in the process of implementing, a programme for fitting low NOx burners. The fitment programmes vary in their extent and in some cases are due to take several years to complete.

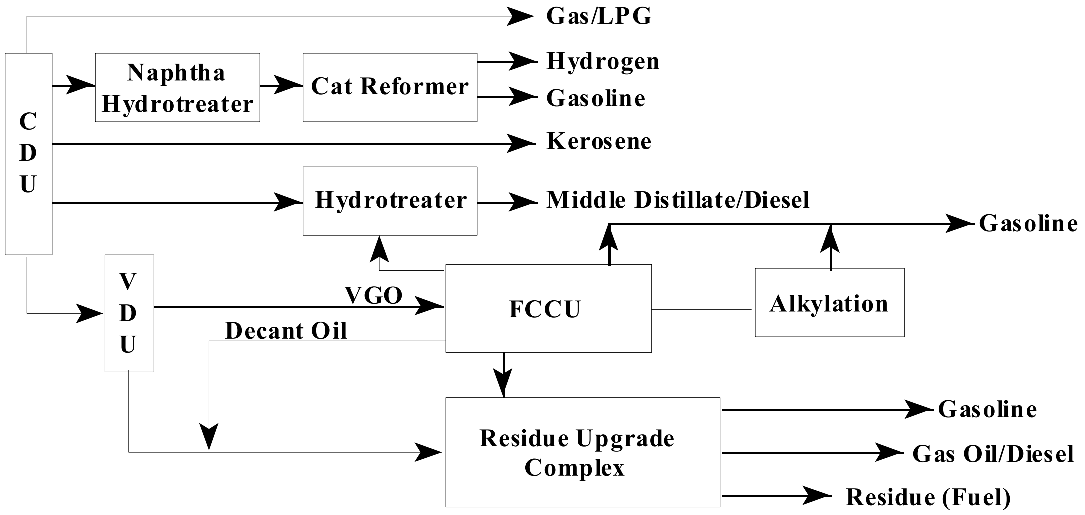


Figure 3.3 Simplified flowscheme for a residue upgrading refinery

All boilers and most of the furnaces are of the forced draft type, i.e. fans force air into the combustion chambers of the burners. However, approximately one third of fired heaters (furnaces) on UK refineries are of natural draft type. Pressure drops are therefore an important consideration on these types of furnace and the low pressure drops on which they operate will limit any flue gas abatement options.

As discussed above, fuel oil firing normally results in higher emissions of SO_2, NOx and particulates compared with fuel gas/natural gas firing. In addition furnace operation is more difficult when firing oil, and more shutdowns for furnace-tube cleaning may be required. Typical SO_2, NOx and particulate emissions from firing oil and gas fuels are presented in Table 3.1. No UK refineries currently apply catalytic reduction of NOx in flue gas. Furthermore no refineries utilise flue gas abatement to reduce emissions of particulate or sulphur dioxide from combustion processes.

Table 3.1 Typical emissions from combustion plant when firing fuel oil and refinery gas

Pollutant mg/Nm^3 at 3% O_2	Fuel oil 1% S	Fuel oil 3.5% S	Refinery gas
SO_2	1650	5750	35
NOx	450	450+	100
Particulates	50	50	Nil

(b) Fluidised catalytic cracking units (FCCU) regenerator flue gas (RFG)

An unabated FCCU on a refinery is a relatively large emitter of pollutants. Emissions from an FCCU can be 20 to 30% of total refinery SO_2 , 15 to 30% NOx, and 30% to 40% particulates. However, these figures can be subject to wider variation.

Generally an FCCU is the biggest single emitter of particulates, although the calciner in a coking unit is also a significant emitter. The particulate released from an FCCU is typically fines of less than 40 μm diameter, attributable to the attrition of process catalyst and coke dust. Currently eight UK refineries operate FCCUs. The current level of abatement is typically two stage internal cyclones, in series, sometimes followed by a third cyclone outside the regenerator. An additional control of particulate release that could be added would be an electrostatic precipitator (ESP). Currently only one UK refinery has installed an ESP. A further refinery has identified that an ESP may be an option for the future. Two refineries have installed a tertiary cyclone. The rest of the UK refineries have only internal cyclones.

The SOx (SO_2 and SO_3) from an FCCU is primarily SO_2 with small fractions converted at higher temperatures in the regenerator to SO_3. The SO_3 condenses at about 140 °C and forms an acid mist sometimes visible at the top of an FCCU stack.

The SO_2 released from an FCCU is directly related to the amount of sulphur in the feedstock. The control of SO_2 releases can be prior to processing, during processing, or post processing. Hydrotreating could be used for reducing the sulphur in the feed to the FCCU; however, only one UK refinery currently hydrotreats a significant proportion of its FCCU feed. None of the refineries in the UK currently has SO_2 flue gas abatement.

The FCCU regenerators can be operated in partial combustion mode where carbon on the catalyst is oxidised to carbon monoxide. Additional heat can then be recovered when the carbon monoxide is incinerated in a dedicated combustion chamber (CO boiler) external to the regenerator. In such cases, as indicated above, NOx emissions will probably be higher than FCCUs not fitted with a CO boiler. A few UK refineries have CO boilers installed.

Except where a CO boiler is installed, NOx concentrations from FCCUs tend to be lower than from combustion plant due to the comparatively lower temperatures in the regenerator.

The regenerator off-gas is a medium pressure, high temperature stream containing a significant amount of energy. It is generally economic to recover this by generating steam in a waste heat boiler, and all operators do this. On larger FCCUs it is often economic to install a power recovery facility by letting down the high temperature flue gas from operating pressure to atmospheric pressure in an expander, and using the power produced to drive the main air blower feeding the regenerator as well as generating additional power. The exact configuration will vary from case to case. A typical 40 000 barrels per day FCCU can raise approximately 8 MWe from a power recovery train. Steam generation from a waste heat boiler and power recovery would not generate extra releases. The majority of UK refineries have power recovery installed.

(c) Sulphur recovery units (SRU)

There are many gaseous streams on the refinery which contain varying concentrations of sulphur in the form of hydrogen sulphide (H_2S). This Sulphur is recovered as elemental sulphur in a two stage process:

1. removal of hydrogen sulphide from gas streams by amine treating
2. regeneration of the amine to release hydrogen sulphide as feed to sulphur recovery units of a licensed design.

An amine solution is used to remove sulphur in the form of H_2S from gaseous streams. Regeneration of the ‘rich’ amine releases H_2S and this, along with other gases such as sour water stripper (SWS) gas, are fed to a Claus SRU. This oxidises the H_2S to elemental sulphur. Depending on the size of the refinery and the level of sulphur in the crude oil being processed, a two or three stage Claus unit will be provided. The tail gas from the SRU is incinerated to destroy H_2S and the resulting flue gas containing SO_2 is released to atmosphere via a stack. If operated well and within the original design parameters, a recovery of between 90% and 96% of the incoming sulphur may be achieved. Due to operating problems, some refineries achieve less.

Further increases in recovery can be achieved by the addition of a tail gas treatment unit (TGTU). A variety of TGTU technology is available. For instance two refineries have installed Shell Claus Offgas Treatment (SCOT) units on their SRUs, and another plans to install one in 1998. One refinery with a lower overall sulphur loading has installed a DOW Sulferox process which is intended for lower amounts of sulphur and will have higher efficiency at the lower loadings.

There is considerable inconsistency in removal and recovery of sulphur in UK refineries. Not all refineries remove sulphur from refinery fuel gas. Some refineries have SWS associated with a specific process unit where the sour water overheads are incinerated directly in the furnaces associated with the process. Where this happens there is inevitably an increase in SO_2 emissions and the loss of the possible conversion to elemental sulphur. Operating efficiency, sparing and back up provision to the main sulphur recovery unit varies. All of these factors affect sulphur recovery efficiency and hence emissions of sulphur dioxide to the atmosphere.

3.2.2 Effluent Water Discharges from Refinery Processes

As far as the level of treatment of wastewater effluent is concerned, a few refineries provide tertiary treatment of effluents by using biological treatment, see section 5.8 for further details. Other refineries typically use only physical methods for oil and water separation.

Pollutants found in wastewater from refineries include hydrocarbons (dissolved and suspended), suspended solids, phenols, sulphides, ammonia and traces of heavy metals. The main process operations contributing to these pollutants comprise the following.

- Desalters - Fresh and/or recycled water is used to wash soluble salts out of the crude oil. The wastewater will contain high levels of salt, sulphides, ammonia and phenol and is directed to the effluent treatment plant.

- Crude distillation unit (CDU) - Aqueous condensate from the CDU is sent for disposal via the sour water stripper (SWS). This will contain sulphides, ammonia, small quantities of chlorides and hydrocarbons.

- Vacuum distillation unit (VDU) - Overhead condensed sour water from the VDU of a similar composition to that from the CDU is similarly routed to the SWS.

- Hydrofining and hydrotreating - Aqueous effluent arising from these types of process operation contain high concentrations of hydrogen sulphide and ammonia. The effluent is therefore fed to the SWS prior to being routed to the effluent treatment plant.

- Fluidised catalytic cracking - Sour water from the scrubber section of the process, containing phenols, ammonia, hydrogen sulphide and hydrogen cyanide, is routed to the SWS.

- Hydrocracking - A low volume, dirty effluent is produced containing ammonia and hydrogen sulphide. This effluent is directed to the SWS.

- Visbreaking - Aqueous condensate from the fractionator condenser containing hydrocarbons and sulphur compounds is sent to the SWS.

- Polymerisation - Water is used to precondition the feed to the process in a wash tower. The purge from the latter is routed to the SWS.

- Etherification - Water is bled to the effluent treatment plant from the methanol recovery part of the process. The stream may contain methanol, formic acid, hydrocarbons, tertiary amyl methy ether (TAME) or methyl tertiary butyl ether (MTBE).

- Coker - Aqueous condensate from the main fractionator is routed to the SWS. This stream contains high concentrations of sulphides and ammonia, as well as cyanides and phenols. Water used in removing the coke from the drum (sometimes termed ‘drilling water’) is filtered and usually recycled.

- Sour water stripper - The sources of sour water are outlined above. The streams contain varying quantities of hydrogen sulphide and/or low molecular weight mercaptans, ammonia, phenols and cyanides. The steam stripped effluent is either reused or sent to the effluent treatment plant.

- In addition to these continuous process flows, effluent arises from site drainage (storm and firewater), ballast water from shipping, cooling water and boiler blowdowns.

3.2.3 VOC Abatement

Many refineries are installing secondary floating roof seals on tanks storing volatile materials to reduce VOC emissions. A number of refineries follow a programme of leak detection and repair (LDAR) to identify and reduce VOC emissions.

3.2.4 Solid Wastes

With regard to solid wastes, one refinery operates a waste incinerator. Refineries actively look for opportunities to minimise waste production. Table 3.2 lists the types of refinery solid waste, their usual origin and their typical disposal method.

3.3 Discussions with Local Inspectors

Copies of recent data from the Public Register were obtained by visiting the appropriate offices of the Environment Agency. In support of this information a discussion was held with each refinery IPC site inspector. A range of questions were asked covering the following issues:

- maintenance practices;
- environmental management practices;
- monitoring practices both by the Environment Agency and the operator;
- site environmental improvements made recently;
- future improvements proposed;
- unauthorised releases;
- environmental performance as a whole;
- compliance with IPC authorisations.

Notes were made of each meeting which were returned to the inspectors. The information provided assistance in understanding the inspectors' view of the main environmental issues at each refinery. No commercially-confidential information held by the inspectors was provided. Discussions relied on the inspectors' own knowledge of the refineries and information which would be available on the Public Register. The individual IPC inspector meeting notes have not been included in this Review although the information provided has been utilised throughout the study where pertinent.

Table 3.2 Refinery waste types and typical disposal routes

Unit	Waste type and composition	Typical disposal method	Comments
Desalting units, lead additive, units, some storage tanks	Desalter sludge and other sludges containing heavy metals such as nickel, vanadium and lead	Require disposal at appropriate licensed site	Classed as special wastes
Desalting units associated with crude oil distillation unit	Sludges	Landfill	
Reformer	Platinum catalysts	Off-site metals recovery	
Hydrotreater	Nickel-molybdenum catalyst	Off-site metals recovery or landfill	Periodic disposal. Option chosen dependent on buoyancy of metals market and economics of recovery process
Isomerisation unit	Platinum catalyst	Off-site metals recovery	Periodic
Fluidised catalytic cracking unit	Catalyst fines comprising silica-alumina catalyst contaminated with vanadium and nickel	Landfill	Drummed and secured before being transported off site.
Polymerisation plant	Catalyst	Landfill	Neutralisation prior to landfill disposal
Tankage	Sludge	Landfill	Centrifugation applied prior to disposal
Effluent treatment plant	Oily sludge	Biological treatment on land farm or incineration or disposal off site	Centrifugation prior to disposal to remove oil (as high as 10%)
Copper sweetening unit	Copper chloride catalyst	Landfill	
Amine regeneration unit	Reclaimed amine sludge	Incineration at hazardous waste facility	
Various units	Coke	Landfill/incineration/ power generation	
Sulphur recovery unit	Activated alumina	Landfill	Infrequent

Unit	Waste type and composition	Typical disposal method	Comments
Sulphur recovery unit	Sulphur	Landfill/ commercial outlet	
Combustion units	Soot/ash	Landfill	
Combustion units	Refractory Materials	Landfill	Periodic. Generated during shutdown and maintenance phases
Boiler feed water units	Alum sludge	Landfill	
Water treatment resins	Resins	Landfill	
Tank storage and handling	Sludges	Landfill or land farm	Leaded sludges transported off site for disposal. Other sludges can either be treated on land farm or sent to landfill
Offices, catering facilities	Domestic waste, offices, sewage etc.	Landfill and to sewage treatment	Most refineries will have their own sewage treatment units

3.4 Inventory of UK Refinery Sector Releases

3.4.1 Introduction

This section provides an inventory of the major refinery releases together with a comparison with National Emissions. Based on this information the major pollutants which have the greatest environmental impact have been identified.

Petroleum refineries submit returns of their releases to the Environment Agency under the system of Integrated Pollution Control (IPC) and these are placed on the Public Register. The returns reflect the information requested by the Environment Agency's site inspectors. They will not include data for authorised but unreported releases such as flares. The monitoring information returns for 1996 form the basis of the data presented in this Review.

Information from the Public Register was available to a greater or lesser extent for the following pollutants :

- SO_2
- NOx
- Particulates
- CO

It should be noted that much of the data are based on calculations and estimates made by the refineries and not on actual measured values. For example, sulphur emissions are typically calculated from the quantity of sulphur in fuels fired, or in hydrocarbons being processed. NOx emissions are estimated based on emission factors derived from periodic stack gas monitoring tests.

In addition to the above, aggregate releases of CO_2 and heavy metals have been estimated based on installed refinery combustion capacities and the total amounts of fuel oil fired, these data generally being available from the Public Register. The VOC release information has been taken from published information provided by the National Environmental Technology Centre (NETCEN) forwarded to them by UKPIA.

With regard to releases of liquid effluents, the data available from the Public Register are very limited, in terms of both the number of refineries reporting mass release data and the determinants reported. Where data are given, the basis on which it has been measured and the assumptions made, make it difficult to analyse and compare. It has not therefore proved possible to assess total effluent releases for refineries.

However, types of effluents typically discharged by the various refinery units and the level of effluent treatment provided by refineries is summarised in Section 3.2.2 above. The possible methods of treatment that can be applied to refinery effluents and the likely improvements needed to treatment plants in the future are discussed in Section 5.8.

3.4.2 Releases of Sulphur Dioxide (SO_2)

General considerations

The major sources of SO_2 emissions are:

- combustion emissions;
- emissions from fluidised catalytic cracker units (FCCUs);
- emissions from sulphur recovery units (SRUs).

The information from the Public Register shows that the percentage contributions of SO_2 from similar refinery processes varies widely between individual UK sites. There are also a number of refinery emission sources including SRU and an FCCU (albeit a small unit) where potentially significant releases of SO_2 emissions are unreported. Further, it is not clear from the public register whether some refineries report SO_2 emissions resulting from the firing in combustion plant of sour gas originating from sour water strippers. None of the refineries except one has reported emissions from flares.

In terms of refinery capacity, the general trend seen is, as expected, one of decreasing SO_2 emissions with decreasing capacity.

In addition, complex refineries in terms of processing are generally expected to have relatively higher emissions although there are some exceptions. However, when related to installed combustion capacity, i.e. emissions divided by installed MW(th) the releases are not particularly high.

As already noted, SO_2 emissions from refineries are affected by the sulphur content of the fuels being processed. Emissions from refineries which process a portion of crudes and/or residues with a higher sulphur content are correspondingly higher.

Combustion emissions

A number of factors influence the total annual SO_2 emissions of a refinery including:

- the installed combustion plant capacity which depends on the refinery size and processing complexity;

- the utilisation of that combustion plant;

- the degree of electrical generation on site, as opposed to imported electricity, which entails off-site emissions;

- the quality of the fuel fired in terms of sulphur content.

All refineries report SO_2 releases from combustion plant. From 1996 data on the Public Register the estimated total release of SO_2 from combustion in eleven UK refineries was 64 731 tonnes per year.

Emissions from FCCUs

The amount of SO_2 released by the FCCU depends to a large extent on the amount of sulphur in the feed to the unit.

The FCCU Regenerator continuously burns sulphur-containing coke off the recirculating catalyst. As a result, SO_2 will be emitted together with other products of combustion, including particulates, NOx, CO_2 and some SO_3. As noted in Section 3.2.1 above, carbon monoxide boilers are fitted to FCCUs at some refineries. The mode of operation can affect the emission to air.

The FCCU in most cases contributes approximately 15% to 30% to total SO_2 refinery emissions. The emissions vary markedly and do not follow the trend of lower emissions for smaller refinery size. Eight refineries operate FCCUs. Six refineries reported SO_2 releases from FCCUs. One other refinery did not report FCCU emissions separately from other non-combustion emissions. Another refinery did not report FCCU emissions at all. Three other refineries do not operate this type of plant. From 1996 data on the Public Register, the estimated total release of SO_2 from reported refinery FCCUs was 20 072 tonnes per year.

Emissions from SRUs

SO_2 emissions are affected by the quantity of sour gas fed to the SRU and the efficiency of the SRU. Only some refineries treat sour gas from the sour water strippers which will tend to raise emissions from their SRU slightly but would greatly reduce site-wide emissions. Other refineries incinerate SWS sour gas or burn it in fired heaters. In these cases SO_2 emissions will be higher on a refinery-wide basis as no sulphur is recovered and all sulphur in the SWS sour gas is released as SO_2. Quantities of sour gas will increase where crudes and residues with higher sulphur contents are being processed.

Review of the Public Register information shows that the SRU can be a significant source of SO_2 emissions from refineries. From the limited information available, some refineries have SRU efficiencies above 98% and also have relatively low SO_2 releases.

Other refineries either have poorer performance or did not report their SRU efficiency.

From the 1996 data on the Public Register, comprising reports from six refineries, the estimated total release of SO_2 from UK refinery SRUs was 22 084 tonnes per year. Three other refineries did not report SRU releases. One site did not report SRU emission separately and one site did not operate an SRU.

Summary of SO_2 releases

Figure 3.4 at the back of this section summarises the above data graphically.

3.4.3 Releases of Oxides of Nitrogen (NOx)

General considerations

The principle sources of NOx emissions are:

(a) combustion emissions;
(b) FCCU emissions;
(c) calciner emissions;
(d) miscellaneous.

None of the refineries reported NOx emissions from flares. Reliable NOx factors are, however, difficult to establish. Only two reported emissions from their SRU, though these are likely to be relatively minor releases, particularly for smaller refineries.

Refinery emissions of NOx are mainly influenced by combustion and, to a lesser extent, FCCU releases with relatively small contributions from SRUs and bitumen units. However, a coke calciner is a significant contributor to NOx emissions. Emissions tend to reflect, besides refinery size and complexity, the proportion of fuel oil to refinery fuel gas fired in combustion units.

Combustion emissions

All refineries reported NOx releases from combustion plant. At most refineries combustion contributes over 75% to total NOx emissions.

Refinery emission factors suggest that typically fuel oil firing produces two to three times as much NOx as refinery fuel gas firing for the same weight of fuel burnt (see Chapter 5). However, at refineries where emission factors have been developed for individual furnaces through stack monitoring, emission factors for NOx production range from two to seven times higher when firing on fuel oil than when firing on fuel gas. Refineries firing a high proportion of fuel oil would therefore be expected to have a relatively high NOx emission. For those refineries where the actual firing mix is known, the relative emissions follow the trend expected by the fuel mix.

The estimated total release of NOx from the eleven refinery combustion sources is 24 222 tonnes per year.

FCCU emissions

Five of the eight refineries with FCCUs reported NOx emissions from these units. The data available show the contribution of FCCU to refinery NOx emissions varies widely between 15% to 45% of total refinery emissions. NOx emissions from the regenerator are attributable to a number of factors including:

- thermal oxidation of nitrogen in combustion air;
- thermal oxidation of nitrogen compounds in the coke;
- design of the unit;
- presence or absence of a fired waste heat boiler/CO boiler.

The data suggest that further review of the way in which the emission data are generated should be made, as well as how plant operation affects emissions.

For the five refineries that report NOx from FCCUs, the estimated total emission is 4576 tonnes per year.

Calciner emissions

Emissions from petroleum coke calciners are not reported but their contribution to the overall NOx emissions has been estimated at about 1038 tonnes per year.

Miscellaneous

Other sources of NOx emissions which have been identified are as follows.

- **SRU**

Data on NOx and particulate releases from SRUs are available for one site only and no emission limits are set. On this basis the SRU as a source of NOx appears to be minor.

- **Bitumen plant**

Five refineries operate bitumen plants. Different grades of bitumen are produced in the refinery by 'blowing' bitumen to increase hardness as measured by the bitumen penetration test. The blowing strips off lighter hydrocarbons from the bitumen and the hydrocarbon-laden air is subsequently incinerated.

The total emission of NOx from SRUs and bitumen plants sources has been estimated as 340 tonnes per year.

Summary of NOx releases

Figure 3.5 at the back of this section summarises the above data graphically.

3.4.4 Releases of Particulates

General considerations

The main sources of particulate emissions are most likely to be from combustion emissions when burning fuel oil, particularly heavy fuel oil, and from FCCUs. A coke calciner can be a major source but this is only installed at one UK refinery. Flares can also be a source of particulates if not operated properly.

It is noteworthy that in the case of particulate emissions at one refinery the SRU is reported to be responsible for 16% of total particulate emissions. If taken at face value, it would suggest that the SRU as a source of particulates may be worthy of consideration at other refineries.

Total emissions of particulates have been reported from nine refineries as 2555 tonnes per year. However, of these five refineries do not specify the source of the particulate, i.e. combustion or FCCU. Therefore it is not possible from the data available on the Public Register to split the particulate emissions reliably into sources from combustion, FCCU or Calciner. This total emission figure may also be under-reported as two refineries do not report their particulate emissions. Assuming their releases are similar to others, the total particulate emission for all eleven refineries is likely to be about 3000 tonnes per year.

3.4.5 Releases of Carbon Monoxide

Very little data are available on the emissions of CO from refineries. The CO emissions from FCCUs are reported for only a limited number of refineries.

3.4.6 Releases of Carbon Dioxide

Some refineries reported actual fuel fired, and from these figures CO_2 emissions were calculated. Other refineries do not report fuel fired and for these CO_2 emissions have been estimated from the installed combustion capacity in MW(th) assuming 90% utilisation. From these calculations and estimates, CO_2 releases from UK refineries are approximately 14 300 kilo tonnes per year.

3.4.7 Releases of Heavy Metals

Traces of heavy metals are found in solid and liquid fossil fuels. An estimate of refinery emissions of heavy metals resulting from the firing of fuel oil has been made using emission factors used by the National Environmental Technology Centre (NETCEN) in their compilation of the National Atmospheric Emissions Inventory (Salway A et al (1997)). Estimates are based on the quantities of fuel oil fired which have been provided by the refineries or estimated as per the CO_2 estimates above.

The release of heavy metals will reflect the installed combustion capacity fired by fuel oil since refinery fuel gas and natural gas do not contain heavy metals. The sum of emissions for ten heavy metals from all UK refinery combustion plant for 1996 is shown in Table 3.3. The table also shows the estimated total UK heavy metal emissions for 1994 taken from the National Atmospheric Emissions Inventory and the percentage contribution from UK refinery combustion for that year. Only nickel and vanadium emissions from refineries would appear to be significant in the context of total UK emissions.

Table 3.3 Refinery heavy metal emissions (1996) and as a proportion of total UK emissions for 1995

Heavy metal	Refinery combustion emission (tonnes)	UK emissions (tonnes)	% of UK emissions
As	0.064	98	0.07
Cd	0.019	24	0.08
Cu	1.15	74	1.6
Cr	0.77	60	1.2
Ni	67.37	402	16.8
Pb	1.56	1 468	0.1
Se	0.96	92	1.0
Zn	1.44	1 291	0.11
Hg	0.031	20	0.16
V	360	1 659	21.7

3.4.8 Releases of VOCs

Emissions of VOCs are estimated by each refinery to a protocol developed by the industry. Each refinery submits its VOC emission estimates to the UKPIA annually. The UKPIA aggregate the data and submit the total industry sector data to NETCEN for inclusion in the UK National Emissions Inventory. Estimates for five categories of refinery sources, for 1993 to 1996 are reproduced in Table 3.4 below.

Table 3.4 Emission of volatile organic compounds from UK refineries (kilotonnes)

Source	1993	1994	1995	1996
Flare	2	1	1	2
Tankage	18	13	12	12
Drainage	38	34	28	28
Process	42	51	47	34
Rail/Road loading	n/a	4	3	2
Total	100	103	91	78

From Table 3.4 it may be seen that refinery emissions have been steadily improving in the period 1993 to1996. The VOC data for individual refineries were submitted to the Public Register by one refinery only.

3.4.9 Total Sector Emissions Relative to National Emissions

Reasonably complete release data are available from the Public Register for the pollutants SO_2, NOx, and to a lesser extent particulates. Releases have been compared with the nationwide releases for these pollutants presented in the National Atmospheric Emissions Inventory. The most recent national estimates are for 1995.

Other comparative data have been included for the emissions of CO_2 and VOCs.

A summary of refinery pollutant emissions as a proportion of national emissions is presented below in Table 3.5.

Data from CONCAWE, the European Oil industries organisation for environment, safety and health protection, show UK refineries constitute about 27% of SO_2 emissions from European refineries.

- **National emissions of sulphur dioxide (SO_2)**

The National Inventory shows that SO_2 emissions have been steadily decreasing. National emissions in 1995 were 2365 kilotonnes. Refinery SO_2 emissions totalled at least 119 kilotonnes in 1996 which indicates refineries contribute approximately 5% to national SO_2 emissions, assuming no major changes have occurred in the National Inventory between 1995 and 1996.

- **National emissions of oxides of nitrogen (NOx)**

The National Inventory indicates total NOx emissions to be 2295 kilotonnes in 1995 with a general trend in reduction in levels of releases. Refinery NOx emissions were at least 30 kilotonnes in 1996 which represents approximately 1.3% of national emissions.

- **National emissions of particulates**

National emissions of black smoke have been estimated at 356 kilotonnes in 1995. Refinery particulate emissions would be largely classified as black smoke. However, as previously stated, the refinery particulate emission data are not complete as a number of refineries do not report combustion particulate emissions. The available data show an emission of 2.6 kilo tonnes per year with an estimated pro rated value of 3.0 kilo tonnes per year which represents at least 0.7% of national emissions.

- **National emissions of carbon dioxide CO_2**

Total emissions in the UK in 1995 were estimated at 148.2 million tonnes of carbon as CO_2 **.** This would indicate that refinery combustion processes, which produce about 14 300 kilo tonnes per year, are responsible for approximately 2.6% of UK emissions.

- **National emissions of heavy metals**

The estimated releases and comparison with National Emissions are given in Table 3.3 in Section 3.4.7.

Table 3.5 Summary of refinery emissions (1996) vs. national emissions (1995)

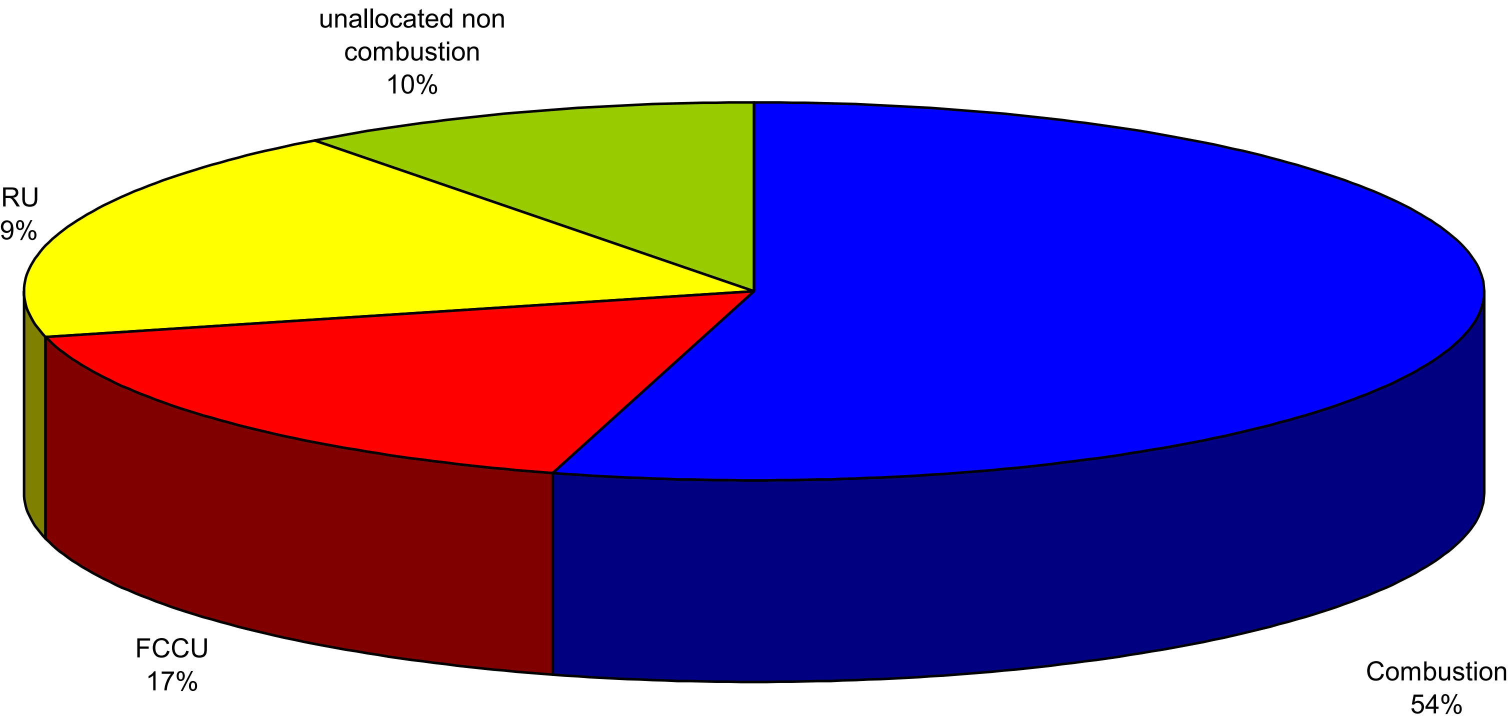
Pollutant	Refinery emission (kt/y)	National emission (kt/y)	Refinery emission %
Sulphur dioxide	119	2 365	5.0
Oxides of nitrogen	30	2 295	1.3
Particulates	3	356	0.8
Carbon dioxide (as carbon)	14 300	148 200	2.6
VOC	78	2 337	3.3
Ni	0.067	0.402	16.7
V	0.36	1.659	21.7

3.4.10 Conclusions

Based on the analysis included in this section, it is clear that refineries contribute a relatively small, but not an insignificant, amount of the total national releases of sulphur dioxide, carbon dioxide, volatile organic compounds, and, to a lesser extent, oxides of nitrogen. The release of particulates is relatively modest. The release of the heavy metals, nickel and vanadium is a significant proportion of the national emissions of these two metals.

As previously stated, the effect of refinery releases on their immediate localities does not form part of this Review.

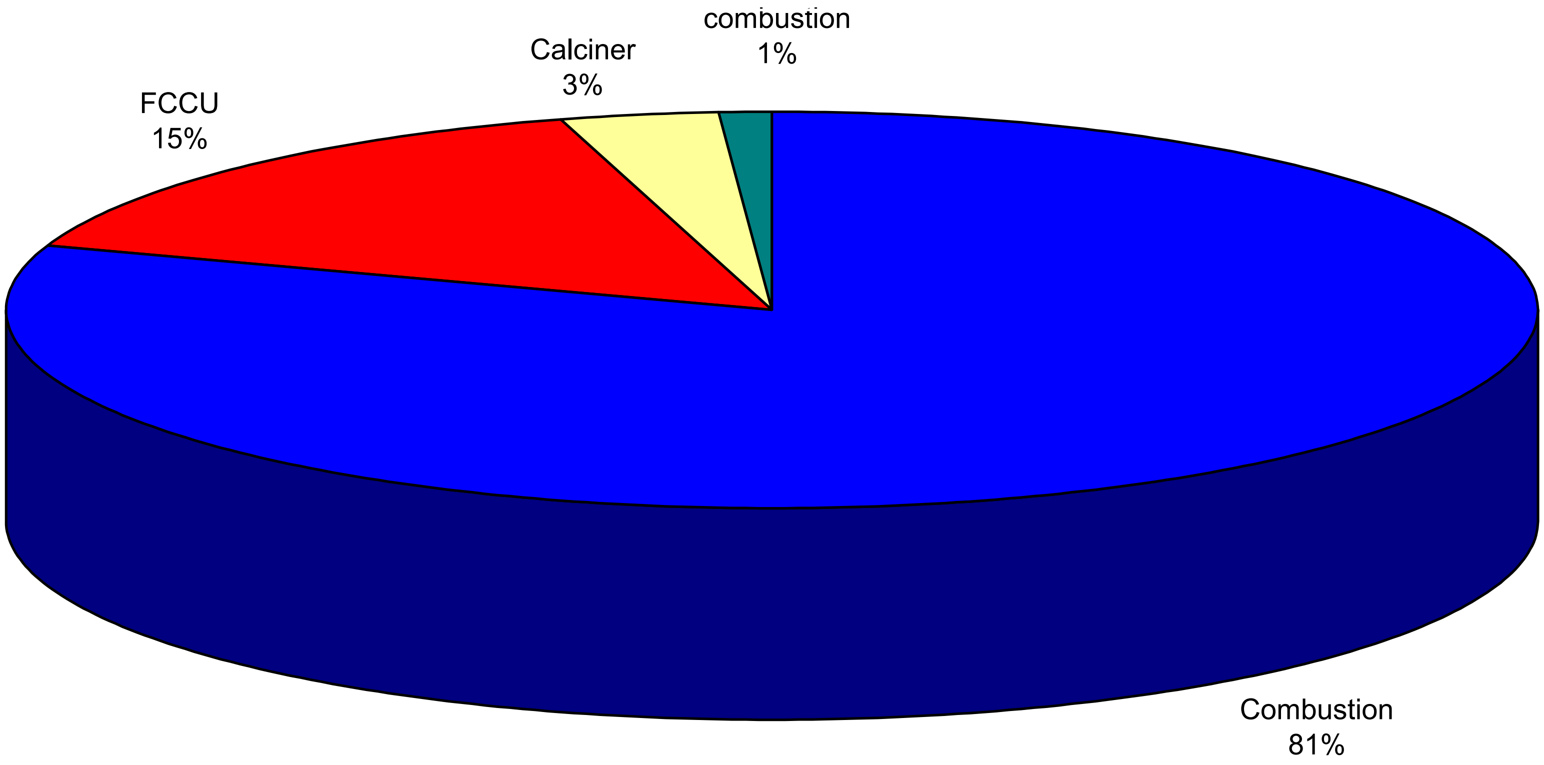
Figure 3.4 **Breakdown of UK refinery SO_2 emissions by source**



	t/y	%	
Combustion emissions	64731	54	data from 11 refineries
FCCU emissions	20072	17	data from 6 refineries
SRU emissions	22084	19	data from 6 refineries
unallocated non-combustion emissions	12262	10	
Total reported emissions	119149	100	data from 11 refineries

There was generally no data for flares.

Figure 3.5 **Breakdown of UK refinery NOx emissions by source**



	t/y	%	
Combustion emissions	24222	80.3	data from 11 refineries
FCCU emissions	4576	15.2	data from 5 refineries
Calciner emissions	1038	3.4	data from 1 refineries
Unallocated non-combustion emissions	340	1.1	
Total reported emissions	30176	100	data from 11 refineries

4. WORLD-WIDE REFINERY BEST PRACTICE

4.1 Introduction

This Chapter reviews the environmental abatement practice in the following countries, which are generally regarded as the leading countries or regions in environmental protection.

- USA
- Scandinavia
- Japan
- The Netherlands

4.2 USA

4.2.1 Regulations

The USA applies the terms LAER (Lowest Achievable Emission Rate) and BACT (Best Available Control Technology). LAER focuses on requiring the most stringent emission limitation achieved in practice for the category of source under consideration. Economics are not considered at all in LAER, whereas BACT is largely concerned with the economic feasibility of a control technology. BACT is a requirement applicable to major sources which emit pollutants and requires consideration of each source on a case-by-case basis. BACT is generally a performance requirement not an equipment requirement, and requires evaluation of alternative production processes and available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques. BACT allows for the investigation of the economic feasibility of technologically-viable measures, methods, controls or limitations.

Consideration of BACT is required for sources or units above the following thresholds:

Pollutant	Threshold release values tonnes/year
Sulphur dioxide	40
Oxides of nitrogen	40
Carbon monoxide	100
Particulate matter less than 10 µm	15
Volatile organic compounds	40

The definition of BACT also states a minimum requirement as “In no event shall application of BACT result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard represented under the New Source Performance Standards (NSPS)”. In addition the control of acid rain is planned to be achieved by imposing NOx emission limits on a pounds per million Btu annual average basis. The United States Environmental Protection Agency (USEPA) foresees that this approach will force industry to explore energy efficiency and enhanced emissions control technology.

Consideration of BACT for a refinery process unit is applied if a permitted emission threshold is exceeded. BACT is applied to new process units, process units that are reconstructed, or process units that undergo a major modification.

State legislation is superimposed on the Federal BACT approach where there is additional concern over pollutant levels. For example, California and Delaware apply the LAER approach to mitigate low-level ozone. As NOx is a precursor to ozone the NOx regulations are, in consequence, stringent. Any plant or unit that is reconstructed or replaced is considered to be new and as such comes under the New Source Performance Standards. Emission credits cannot be carried over and the new limit under LAER must achieve less than 25 tonnes per year of NOx.

4.2.2 'Bubble' Approach

The Bubble emission permit system exists in the USA, where the setting of an overall emission target level for given pollutants emitted from an integrated processing complex is established. The level of pollution varies markedly from one area to another and so a graduated classification scheme has been implemented whereby areas are categorised by their air quality status. The pollution reduction regulations of a certain area are scaled accordingly and deadlines for compliance set.

4.2.3 Emissions Trading

The USA has introduced 'emission trading' where refineries can 'bank' future emissions by shutting down equipment or by using control equipment where it is not regulatory driven. Each state can establish its own emission trading regulations for a specific pollutant; for example, New Jersey has a NOx trading programme. Emissions that are banked are generally not based on licensed limits, but on how the equipment has been operating in the recent past, usually the previous two years. The value of banked emissions have a time limit and decrease in value until they disappear completely, at some time in the future. Generally emissions will be lower using the banking system.

4.2.4 Use of Abatement Technology

Table 4.1 shows examples of abatement technology and their current application by oil companies in the USA.

Abatement Techniques - Air

SO_2

The SO_2 emission limit for New Source Performance Standards is 700 mg/Nm^3. Techniques already in use on USA refineries to achieve this include:

(i) scrubbing of flue gases. This has been in use since the 1970s. Recent trends include forced oxidation to produce gypsum, a commercial product. Scrubbing is applied typically to FCCU flue gases;
(ii) three stage Claus unit on sulphur recovery units;
(iii) additional off-gas treatment such as proprietary Beavon or Shell Claus Off-gas Treatment (SCOT). These are used for larger plants;

NOx

The principal techniques in use to control NOx in refineries are:

(i) use of low NOx and ultra-low NOx burners in combustion equipment;
(ii) selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR), used in California and Delaware as LAER technology).

Particulates

US regulatory authorities have set an NSPS requirement generally for FCCUs of 1lb of particulate matter per 1000 lbs of coke burned off (equates approximately to 75 mg/Nm^3). Abatement technology permitted under the BACT scenario and currently in use includes:

(i) tertiary external cyclones;
(ii) ESPs for fine particulates.
(iii) wet gas scrubbing;

VOCs

BACT used to reduce VOC emissions in refineries includes:

(i) regenerable activated-carbon vapour recovery units;
(ii) temperature controlled vapour combustors;
(iii) vapour recovery during loading/unloading operations at marine terminals;
(iv) secondary seals within storage tanks;
(v) leak Detection and Repair Programme (LDAR) to minimise fugitive emissions;
(vi) use of closed systems for wastewater treatment collectors to restrict losses to atmosphere.

Abatement techniques - water

Standard regulatory requirements to reduce water pollutant levels include use of BACT.

Strict limits apply to toxic and conventional pollutants, BOD, COD, TOC, ammonia, sulphides and phenolics.

BACT includes:

(i) waste water management;
(ii) segregation of process water, storm water and oily storm water;
(iii) oil segregation at source;
(iv) spill prevention and control;
(v) measures to maintain segregation;
(vi) enclosed CPI separator (corrugated plate interceptor) that vents to carbon absorbers;
(vii) filtration and carbon systems to provide final water polishing.

Abatement techniques - land

The USA operates a Toxic Release Inventory programme which includes solid wastes whereby owners and users must report releases of listed substances. Federal law prevents the application of toxic wastes to land.

BACT includes:

(i) incineration;
(ii) recycling;
(iii) stabilisation/solidification;
(iv) use of special purpose off-site disposal;
(v) land farming of residual sludge, provided that concentrations of components meet federal and local regulations.

Table 4.1 Examples of USA abatement applications

Facility	State(1)	Process	Efficiency	Control
NOx abatement measures				
Chevron	MS	Process heaters	63%	Ultra-Low NOx burners
Fletcher Oil	CA	Vacuum heater for gas oil prior to vacuum distillation	85%	Selective catalytic reduction
Koch Refining Company	MN	FCCU	-	Low excess air on catalyst; regenerator with combustion control on the CO boiler
SO_2 abatement measures				
Texaco	CA	SRU	99.9%	Three stage Claus, amine based tail gas treating unit
Transamerican	LA	SRU	99.9%	Three stage Claus, SCOT inc.
Transamerican	LA	FCCU regenerator	90%	Dry lime injection scrubber
Mobil Oil Company	CA	TEOR(2) operation with Sulphur removal	95%	Sulphur scrubbing system for H_2S
Particulate abatement measures				
Murphy Oil	LA	FCCU	90.8%	Electrostatic Precipitators
Particulate and SO_2 abatement measures				
Shell	LA	FCCU regenerator	-	Wet gas scrubber (to adhere to NSPS)
Maricopa	AZ	Process heaters and boilers	-	Wet scrubber
Transamerican	LA	FCCU regenerator	93%	Tertiary cyclone with venturi scrubber
VOC				
BP, Toledo refinery	OH	Stormwater diversion chamber	95%	Carbon canisters
BP, Toledo refinery	OH	Coker	99%	Flare
Mobil Oil Company	AL	Claus sulphur recovery unit	-	Thermal oxidizer, increase operating temperature
Texaco Refining	CA	Surge tank	98%	Vapour recovery system

(1) State codes
MS - Missouri MN - Minnesota AZ - Arizona AL - Alabama
CA - California LA - Louisiana OH - Ohio

(2) TEOR Thermally Enhanced Oil Recovery

4.3 Scandinavia

4.3.1 Regulations

Scandinavian countries generally have more stringent regulatory requirements than the UK, although there are slight variations between the different Scandinavian countries. Financial incentives may be offered by Governments to meet requirements, e.g. removal/reduction of NOx emissions.

Denmark, Sweden and Finland have established wide-ranging energy taxes including special levies for carbon- based fuels. Sweden has also introduced stringent requirements to minimise all types of emissions. Use of high sulphur fuels (>0.5%) is prohibited throughout the country. Sulphur recovery must be in excess of 99% including the flaring of residual tail gas. NOx and particulates must be reduced to the minimum feasible level. Norway has introduced a special tax duty to minimise emissions of CO_2 and NOx during flaring on a per tonne of oil produced basis. Low sulphur fuels are also used in Norway.

Denmark has set SO_2 emission limit values of 1000 mg/Nm^3 for residual product fuels , with a maximum of 1% S in fuel oil. SO_2 limits for gaseous and LPG fuels have been set at much lower levels (35 mg/Nm^3 to 5 mg/Nm^3). NOx levels have been set at 225 mg/Nm^3 for both liquid and gaseous fuels.

In Sweden the total permitted release levels for the Scanraff Refinery are 2000 tonnes per year SO_2 and 1000 tonnes per year NOx. The absolute limit of particulates from the FCCU is 75 mg/Nm^3. The crude capacity for this refinery is 200 000 barrels per day or 9.5 million tonnes per year which is comparable in size to most UK refineries.

Release levels for the whole of the Mongstad Refinery, Norway's main refinery, are 2000 tonnes per year for SO_2 and 2150 tonnes per year for NOx. The crude capacity for this refinery is 130 000 barrels per day or 6.2 million tonnes per year.

4.3.2 The 'Bubble' Approach

The bubble concept is applied to overall emissions from refineries. This requires that new processes are included within the current permitted emission inventory for a site. In consequence emissions from existing plant must be reduced to accommodate new plant operation.

4.3.3 Use of Abatement Technology

Abatement techniques - air

SO_2

Refinery operators use advanced abatement technology to meet the stringent emission limits of Scandinavia. The technology includes:

(i) additional SRU off-gas treatment such as the SCOT process (Sweden);
(ii) SRU recovery efficiency >99.5%;
(iii) refinery fuel gas only allowed to be fired in refineries, except for start-ups when fuel oil can be used.

NOx

NOx abatement technology is essential to meet the strict NOx requirements. Technology used to date includes:

(i) low or ultra-low NOx burners are standard or retrofitted;
(ii) SCR has been retrofitted to the Scanraff refinery FCCU.

Particulates

Abatement technology includes the use of tertiary treatment for FCCUs, e.g. hot ceramic filters retrofitted to the underflow of third stage cyclones.

VOCs

Abatement technology used in Sweden and Denmark to minimise VOC emissions includes vapour recovery equipment on storage tanks.

4.4 Japan

4.4.1 Regulations

Japan is a highly industrialised country with significant limitations on available land for both urban and industrial development. In consequence the pollution regulations are stringent. This is particularly applicable to high-density industry complex ‘hot spots’ such as Tokyo Bay and Osaka Bay. In these areas local government regulations impose further stringent emission limits to the national regulations. In general Japanese national regulations do not specify particular technology requirements such as BAT or BACT. Instead, Japanese regulations specify emission limits in the form of concentrations and quantities. Total pollutant load control is required for the ‘hot spot’ regions.

Local regulations may, however, identify specific process requirements or abatement technology, particularly for VOCs.

Local government has the right of final acceptance of plant operations through its environmental permit system.

4.4.2 Bubble Approach

Due to the density of industrial complexes Japanese legislation is applied on an area basis. A total emission load control is applied for NOx and SO_2. Consequently, when new processes or plants are planned, fuel and emission control strategies are required to make adjustments to existing plant in order to meet the total limits.

4.4.3 Use of Abatement Technology

The need to meet stringent emission requirements dictates the need to apply similar abatement technology/facilities throughout Japanese refineries. Japan also tends to apply 'maximum resource recovery' techniques to make use of all by-products from processes.

Abatement techniques - air

SO_2

Fuel oil sulphur content is restricted to a maximum 1.2%. However, clean refinery fuel gas is regularly used to avoid the need for abatement technology.

Abatement technology includes:

(i) high-efficiency sulphur recovery;
(ii) scrubbing of flue gas using limestone/gypsum systems, $Mg(OH)_2$ or NaOH.

NOx

Abatement technology includes:

(i) low NOx and ultra-low NOx burners;
(ii) clean fuel gas;
(iii) use of SCR (selective catalytic reduction).

Particulates

Electrostatic precipitators have been used to reduce particulate emissions from FCCUs.

VOCs

Control of VOC emissions tends to be based on local government initiatives. Abatement technology used includes vapour recovery at loading facilities as well as other usual VOC abatement methods.

4.5 The Netherlands

4.5.1 Regulations

Refineries negotiate their own release levels with their local authorities.

4.5.2 Use of Abatement Technology

Abatement techniques - air

The Shell Refinery at Pernis, in the Netherlands, has applied heavy oil gasification where some of the syngas is burnt as fuel on the refinery to produce steam from the combined cycle gas turbine. SO_2 emissions are virtually zero from this process, as after gasification, the H_2S and other sulphur components are removed from the gas phase. Shell has an agreement with the Dutch Government that the refinery will not be subject to tightening of emissions regulations for another 20 years.

No flue gas abatement plant (wet scrubbing, SCR etc.) is fitted to Dutch refinery processes, but firing of fuel oil is not permitted. All combustion plant fire fuel gas and are fitted with low NOx and ultra-low NOx burners; therefore SO_2, NOx and particulate releases will be lower than in the UK. (It should be noted that Rotterdam Europort provides a major outlet for fuel oil, supplied as ships' bunker fuel.)

4.6 Summary and Comparison with UK Practice

4.6.1 General

The Scandinavian countries, Japan and California USA have the most rigorous requirements for pollution control and reduction. Such countries tend to apply the lowest-achievable emission rate as a standard with limited, if any, consideration to economics. Japan has achieved the lowest per capita emissions for SO_2, NOx and particulates within the OECD countries. This reflects the close proximity of large populations to heavily-industrialised areas.

The other parts of the USA and the other countries that have been surveyed together with the UK, usually apply cost versus abatement performance to some degree.

4.6.2 Bubble Permit System

Most countries operate the bubble permit system for emissions, whereby the refinery is classed as an integrated unit and individual refinery release levels are established by the Authorities. New plant has to be accommodated within the existing set limits. Therefore new plant, or major modifications, imply increasingly stringent control measures at a refinery. In the UK there is not generally a requirement at present to accommodate new plant within existing limits.

4.6.3 Fuel Constraints

Crude feedstock quality is regulated in Scandinavia and Japan, as is the allowable sulphur content in refinery fuel oil and gas (< 0.5% in Sweden and between 0.5% and 1.2% in Japan). Other countries, like the USA, do not specify a limit, but where higher sulphur content fuels are used, abatement equipment has to be installed. Generally, end-of-pipe technology is avoided if other techniques, such as fuel substitution, fuel cleaning and advanced combustion techniques are effectively employed. At present there is no general requirement to limit sulphur levels in refinery fuels in the UK.

4.6.4 SO_2 Emissions

Flue gas abatement on refineries is mainly used in the USA. In Europe the preference is for the combustion of clean fuels, particularly gas, rather than, for example, the use of wet gas scrubbing.

Increasingly, hydrotreatment, the removal of sulphur in the feedstock or product stream, is being utilised to reduce sulphur emissions from fuels, especially in the USA, Japan and Scandinavia.

4.6.5 NOx Emissions

Scandinavia has established incentives to reduce NOx emissions.

In all the countries the use of low NOx burners is considered the minimum abatement technology to reduce NOx emissions. USA, Scandinavia and Japan tend to use ultra-low NOx burners, and in some cases flue gas recirculation (FGR). It is noteworthy that in the UK the combustion plant on several of the refineries are not fully fitted with low NOx burners. The use of SCR is not considered to be the best available technology in the majority of the USA, due to higher capital and operating costs. In some states, however, like California and Delaware, there are strict NOx limits to minimise low-level ozone formation and use of SCR is recognised as representing LAER. SCR and SNCR (selective non-catalytic reduction) are not generally used downstream of furnaces and boilers on refineries in Europe, but FCCU plants in Sweden, Hamburg and Rotterdam have been retrofitted with SCR technology.

Combined SO_2/NOx removal systems, recently in the development stage, are now becoming available. Potentially they may be equivalent or preferable to other systems currently in use, due to their favourable cost and overall removal efficiency (see Section 5.4.3).

4.6.6 Particulates

Cyclones used for abatement of FCCU particulates are not very efficient at collecting the smaller particles and are supplemented by the addition of ESPs in the USA and Japan. Only one refinery in the UK has an ESP fitted to its FCCU and another is considering it for the future.

Sweden has utilised newer hot ceramic filter technology, with varying success. The technique is continuing to be developed and may become more standard abatement technology in the future.

4.6.7 VOCs

The USEPA requires refineries to prepare and implement LDAR programmes. These programmes are being implemented in many refineries, world-wide, in an effort to reduce fugitive emissions of hydrocarbons, pump seals, valves and flanges. It is considered that these programmes are likely to result in significant reductions of fugitive emissions. In the UK there is no regulatory requirement for VOC control across the refinery sector.

4.6.8 Conclusion

When the above data are compared with the current abatement measures applied to UK refineries, as described above and in Chapter 3, it can be seen that the UK does not compare particularly favourably with the advanced countries surveyed. Overall it could be concluded that the UK is behind the USA in terms of application of abatement techniques, and significantly behind Scandinavia and Japan, which are probably the world’s leading investors in environmental protection.

5. POLLUTION REDUCTION ISSUES, TECHNIQUES AND COSTS

5.1 Introduction

This Chapter reviews the main refinery plant and techniques that are available to reduce polluting releases. Abatement techniques are described for each pollutant, SO_2, NOx , particulates etc. Approximate costs of abatement plant are also discussed and these are summarised in Table 5.3 at the back of this section.

Methods for abatement of polluting releases generally fall into three main areas;

- Upstream abatement, for example, ensuring the fuel combusted is as 'clean' as possible. In this respect Table 3.1 in Chapter 3 highlighted the improvements that can be obtained in SO_2, NOx and particulate releases by burning very low sulphur refinery gas or natural gas.

- Using abatement techniques inside a furnace or reactor where combustion or a chemical reaction is taking place.

- Abating releases downstream of combustion plant or reactors. These techniques are sometimes known as 'end-of-pipe solutions'. One problem with these is that equipment tends to be larger and hence more expensive than it might otherwise be because other large-volume inert substances may also be present in the flow. For example, by volume, there is four times as much nitrogen in air than oxygen and therefore combustion flue gas is very largely composed of nitrogen.

5.2 Sulphur and Sulphur Dioxide Abatement

5.2.1 Upstream Abatement of Sulphur (Fuel Cleaning)

(a) Hydrotreatment and associated processes

Hydrotreatment is a general term for a range of processes for the removal of sulphur from refinery feed and product streams. The process removes sulphur, under pressure and elevated temperature in the presence of hydrogen over a catalyst, by conversion of the sulphur to hydrogen sulphide.

Sulphur is generally more readily removed from the lighter, lower boiling range, hydrocarbon streams than from heavier, higher boiling range streams. In the case of the lighter hydrocarbons less hydrogen is required and less reactor pressure, typically 30-40 bar. On the other hand, hydrotreatment of a heavy high sulphur residue stream, where the sulphur is more difficult to remove, and hydrocracking, where the cracking of the heavy fractions is the prime objective and where sulphur is also removed, require pressures of the order of 50-80 bar and 80-150 bar respectively. These types of processes are therefore energy intensive. They also require more catalyst and more hydrogen than the hydrotreatment of lighter streams and are therefore very expensive both in investment costs and operating costs.

Some examples of costs for typical sizes/capacities of hydrotreaters applicable to UK refineries are given in Table 5.1. All installed costs quoted are indicative as the final cost will be influenced by the site-specific factors and the operators' requirements. The scope of each price typically includes licence and engineering fees, civil/foundations, materials, construction/installation and commissioning, but excludes the cost of catalyst, power, steam and other utility plant. These are included in the indicative operating costs given immediately below Table 5.1.

The investment is further increased by the additional demand for hydrogen and the need to convert the hydrogen sulphide produced to liquid or solid sulphur in an expanded sulphur recovery unit (SRU). It may be possible in some cases to supply the extra hydrogen from the catalytic reformer unit by changing its operating conditions slightly. However, if the hydrogen requirement is met from the existing refinery fuel gas system this could lead to less refinery fuel gas being available for combustion processes on the refinery. If this refinery fuel gas were replaced by fuel oil firing in combustion processes, emissions would again increase. Provision of a new steam methane reforming plant to supply the extra hydrogen would be a third option for refiners, but this would be the most expensive alternative. Further, the addition of a hydrotreatment or hydrocracker unit will itself incur emissions including NOx and CO_2 and perhaps SO_2 .

As catalytic cracking is the predominant conversion process in UK refineries, any investment to meet 2005 fuel specifications, and the other market trends described in Chapter 2, is expected to be centred around this key asset. On this basis, a few refiners may install either hydrocracking, or feed hydrotreatment capacity, upstream of the FCCU. Hydrotreatment of feed to the FCCU operates at similar conditions to those used for gas oil and atmospheric residue. Installation of FCCU feed hydrotreatment (or a feed hydrocracker) will reduce the sulphur content in FCCU products, improve their quality and require less final processing. It will also reduce emissions of SO_2 from the regenerator by about 90% and give a reduced catalyst consumption in the FCCU.

However, because of the investment costs it is unrealistic to expect refiners to invest in FCCU feed hydrotreatment purely for abatement of SO_2 emissions from FCCU regenerators, furnaces and boilers burning fuel oil. However, some refiners may well consider adopting such a scheme in order to meet a number of requirements such as those described above, which would include emission abatement. In this case, refiners should have adequate information made available to them to enable them to consider future emissions abatement requirements at the same time as they are considering upgrading to meet the 2005 specifications.

It can take three to four years to add complex new upgrading plant and therefore such requirements would need to be made clear by as soon as possible as most refiners are now planning their investment to meet the 2005 fuel specifications.

Table 5.1 Hydrotreater costs applicable to UK refineries

Type of hydrotreater/ service	Typical UK size/capacity (thousands of barrels/day)	Typical capital/installed cost 1997 £million[1]
Naphtha hydrotreatment	30 40 50	42 48 56
Cat. feed hydrotreatment (typical feeds being atmospheric residue and vacuum gas oil)	25 50 75	58 94[2] 133
Vacuum residue hydrotreatment	25 50	75[3] 123
Hydrocracking	30 40	102 132

(1) Costs include necessary interconnections to existing plant for integration purposes.
(2) Typical operating cost for this size unit £16 million/yr
(3) Typical operating cost for this size unit £13 million/yr

The costs in Table 5.1 assume that there is adequate plot space and existing SRU and sour water stripping capacity. Most UK refineries, if contemplating investment in FCCU feed hydrotreatment, residue hydrotreatment or hydrocracking would, as noted above, need new hydrogen-producing facilities. A new hydrogen plant for a 50 k barrels/day FCCU feed hydrotreater or hydrocracker would typically cost in the range of £40 - 50 million.

Syngas

An alternative approach to removing sulphur using FCCU feed hydrotreatment is to process residues by gasification to produce sulphur-free syngas. Syngas could be utilised, as refinery fuel gas for hydrogen, fuel, or chemicals production. This approach would probably result in a refiner producing less transportation fuels. The gasification process is described in more detail in Chapter 7. At present it is relatively expensive and therefore unlikely to be adopted by individual refineries in the near future, but they might consider it on a co-operative basis.

5.2.2 In-Furnace Abatement of SO_2

Boilers and furnaces

For conventional refinery boilers and furnaces the injection of lime or limestone into the furnace for sulphur capture cannot be applied. However, if existing types of boilers were to be replaced, for example, by fluidised bed or circulating fluid boilers, to burn petroleum, coke or heavy asphalts resulting from solvent deasphalting, then lime/limestone injected into the furnace as abatement would be practical. Although this would abate the SO_2 release by about 90%, limestone 100% in excess of the stoichiometric quantity would be required.

FCCU regenerators

SO_2 in the regenerator off-gas of an FCCU can be reduced by using a catalyst which transfers a significant portion of the sulphur associated with the coke on the catalyst to the reactor where it is liberated as hydrogen sulphide. This leaves the reactor with the cracked vapour product for capture in the refinery's amine scrubbing system and thence conversion to sulphur in the SRU.

However, the sulphur-reducing catalyst has a number of adverse effects, including the promotion of SO_3 and NOx in regenerators which are operated in total combustion mode, i.e. where there is no CO boiler. Where there is a CO boiler, i.e. with FCCU regenerators operated with a reducing atmosphere, this type of catalyst may help in reducing polluting emissions without promoting others.

Overall, the method may be seen as an interim solution over a few years where the requirement is to marginally reduce SO_2 emissions in order to meet emission limits. In summary:

Advantages

- SO_2 removal range is from 30-50%;
- additional operating cost for the catalyst is low;
- the method is well established commercially, particularly in the US.

Disadvantages

- SO_3 and NOx increases for FCCUs in total combustion mode;
- poorer yield of products from FCCU;
- reduced FCCU operating flexibility;
- high cost per tonne of SO_2 removed. Typical costs are £2 million per annum for the catalyst for a gas flow of 200 000 Nm^3/hr;
- increased load on the SRU.

5.2.3 Downstream Flue Gas Abatement of SO_2

Boilers/furnaces/FCCU regenerators

The capital cost of equipment for downstream SO_2 abatement on boilers, furnaces and FCCU regenerators is largely dependent upon flue gas flow rates. Typical flue gas flow rates and associated SO_2 concentrations are shown below in Table 5.2 for UK refineries.

Table 5.2 Typical flow rates and concentrations from UK refineries

Flow (Nm^3/hr at 3% O_2)	Concentration of SO_2 (mg/m^3)
Boilers and Furnaces:	
650 000	2000
450 000	2300
250 000	1000
100 000	2000
FCCUs:	
200 000	700
150 000	900
70 000	1100

A number of licensed processes for abatement of SO_2 in flue gases on refineries have been installed around the world. Most of these are operational in the USA. The most popular is wet scrubbing of the flue gas from FCCU units. A brief summary of the wet scrubbing process is given below, together with other scrubbing processes less likely to be suitable for flue gas cleaning in refineries.

As already noted, pressure drop is an important consideration in respect of downstream abatement, particularly in the case of natural draft furnaces and FCCUs. In order that key pieces of refinery equipment such as the FCCU do not need to be shut down solely for maintenance of their abatement plant, such plant needs not only to be effective but also highly reliable and compatible with the operating requirements of the main equipment.

- **Wet gas scrubbing processes**

SO_2, CO_2 and particulates are removed from the flue gas by reaction with an alkaline solution, for example caustic soda or sodium carbonate, to produce a soluble sodium sulphate effluent. The alkaline solution is contacted with the flue gas in a scrubber and the outlet passes to a separator drum. The separated gas flows to a stack and the liquid is recycled to the contacting scrubber. There is a constant purge of slurry and corresponding make up of caustic or carbonate solution. Typically a venturi scrubber is used, although a spray tower may be used as an alternative. This has a similar performance to the venturi scrubber but usually achieves a lower pressure drop.

A suitably-designed wet scrubbing process will normally provide an effective removal efficiency of both SO_2/SO_3 and particulates of up to 90%. With the inclusion of an extra treatment tower, to oxidise the NO to NO_2, an NOx removal efficiency of about 70% may be achieved. Nearly all CO_2 from the gas stream could be absorbed if an alkaline solution such as caustic soda is used as the scrubbing agent. Variants on the process exist which allow for regeneration of the scrubbing agent.

Advantages:

- widely used on FCCU plants in the USA;
- considerable operating experience;
- low pressure drop;
- operates at low temperature;
- no solid deposition problems;
- 90% sulphur and particulate removal.

Disadvantages:

- expensive raw material, e.g. caustic soda, if sulphur and other loadings are high;
- may need flue gas reheat to prevent visible plume mist;
- effluent water purge stream usually produced.

Typical installed capital costs for this type of abatement plant are given in Table 5.3, based on the range of flue gas flows and concentrations shown in Table 5.2.

- **Dry and semi-dry processes**

SO_2 is removed from the flue gas by reaction with lime. The key component of the semi-dry process is a spray drier in which the hot flue gas is contacted with a spray of fine droplets of lime slurry. The SO_2 is absorbed into the droplets forming reaction products which are dried to a fine powder by the hot flue gas.

In the dry process, dry lime is injected into the flue gas as finely-dispersed particles. Both dry and semi-dry processes require downstream dust arrestment systems, such as an electrostatic precipitator (ESP) or bag filtration. The disadvantages may include high pressure drops across the bag filters. The dry process is a relatively low cost solution not requiring a spray drier but only achieves about a 50% sulphur capture.

Dry and semi-dry flue gas desulphurisation (FGD) systems have been extensively used in the power industry world-wide but not widely on refineries and in particular, not on FCCU applications, as their reliability and compatibility are questionable in this type of service.

Advantages:

- 85% sulphur removal with semi-dry process and about 50% removal with dry process;
- operates at the lower temperature end of system;
- solid waste for disposal;
- cheaper raw material;
- capital and operating costs typically less than wet scrubbing.

Disadvantages:

- increased dust load in gas stream; need for dust capture;
- operational difficulties in water/heat balance (spray driers only);
- possibly significant pressure drop across bag filter dust arrestment plant, e.g. bag filters;
- not likely to be suitable for natural draft furnaces or FCCUs and compatibility may be doubtful on other refinery combustion plant.

- **Other SO_2 removal processes**

Other SO_2 removal processes which could be considered, but which have not so far been widely applied to refinery abatement, include the following.

- Limestone gypsum (including semi-dry process). Widely applied in the power industry on large electrical generating stations but less likely to be applicable to the refinery industry due to the amount of solids handling required and the smaller flue gas flows.

- Sea-water scrubbing. This uses the natural alkalinity of the sea water to remove SO_2. SO_2 recovery can be as high as 90%. This application has been successfully applied in a Scandinavian refinery, which is situated on a deep fjord. UK refineries are mostly situated on estuaries. Due to the large volumes of water involved in the process, it is likely that there would be adverse environmental effects from the acidic process effluent discharged into estuarine waters.

- Dry catalytic process. Removal of SO_2 is by absorption on, and reaction with, copper oxide held in a matrix in a reactor vessel.

5.3 Sulphur Recovery Units (SRU) and Sulphur Balance

5.3.1 Sulphur Recovery Units

Overall issues

Insufficient data are available from the Public Register to fully assess existing sulphur plant size, adequacy and performance. This could be remedied if refiners were asked to provide the Environment Agency with sulphur balance data that clearly show the performance of the sulphur plant, see below. This could include releases of sulphur when the unit is shut down both for scheduled and unscheduled reasons. Without significant investment in new plant, any improvement in refinery sulphur recovery will probably be limited by the ability of the existing SRU to accept new stream compositions e.g. sour water stripper (SWS) gas and an increase in volume throughput. A brief description of the key factors involved in improving SRU performance and the design of the SRUs is given below.

Minor capacity improvements

Minor capacity increases obtained by overcoming the pressure profile constraint in SRUs can be gained by a combination of strategies. These may include uprating combustion air blowers, improved sulphur seals, and improving catalyst efficiency thereby reducing the bed pressure drop. This latter route will probably require the operation of the amine unit and sour water stripper at slightly higher pressures, or, alternatively, a tail gas blower may be installed. The increase in throughput that can be gained in this way may vary from 5% to 25%, depending on the mechanical and upstream constraints. More extensive modifications would require substantial SRU downtime and entail significant cost.

The largest throughput improvements normally achieved on existing SRUs is by oxygen enrichment of combustion air, or replacement with pure oxygen. If circumstances permit, 100% increase in throughput can be achieved. This is probably the most cost-effective solution to significantly increasing the refineries' sulphur recovery potential. Significant cost is entailed if the existing SRU is not able to be modified in this way due to age or other constraints. Typical capital costs for SRUs and SRU modifications are given in Table 5.3.

New sulphur recovery unit design

If a new SRU is ultimately required then it should be designed to achieve 99.5% sulphur recovery or better. This would entail at least three catalytic stages plus a tail gas treatment unit (TGTU) or two stages plus integral TGTU. A tail gas incinerator, operating at least at 850 °C with a residence time of one second and reasonable turbulence enhancements to prevent tail gas bypassing, should be provided to ensure residual H_2S of 10 ppm or less in the flue gas.

The new SRU should have an individual on-stream factor exceeding 96%. If the refinery does not have a complete annual shut down, then there should be sufficient parallel or spare capacity to allow the scheduled maintenance activity to proceed every two years, as a minimum, without a significant increase in sulphur emissions as a result.

For the unscheduled times when SRU capacity is unavailable, full emergency SRU treatment should ideally be available. Alternatively, there should be the ability to divert the whole acid gas and SWS gas flows to the SRU tail gas incinerator for a period not exceeding an agreed short period of time. A sour flare design should not be used.

Typical costs for a range of SRU size applicable to UK refineries are given in Table 5.3.

5.3.2 Refinery Sulphur Balance

In addition to the suggestion that a sulphur balance is applied to the SRU, analysis of data from the Public Register show that, with the exception of one refinery, there are insufficient data and lack of consistent data to assess a refinery's overall performance in abating sulphur releases. For example an SRU may be operating very well but that is relatively unimportant if most of the sulphur that is being emitted from combustion processes or sulphur-bearing streams are piped directly to furnaces for disposal.

Figure 5.1 shows the typical sulphur-bearing streams into and leaving a refinery. It is suggested that the Environment Agency might consider asking refiners in the future, as part of their returns to their local Environment Agency inspector, to regularly report their overall refinery sulphur balance in the form of the sulphur in the streams entering and leaving the refinery. All recognised sulphur-bearing streams should be accounted for in this exercise.

5.4 Abatement of Oxides of Nitrogen (NOx)

5.4.1 Upstream Abatement of NOx

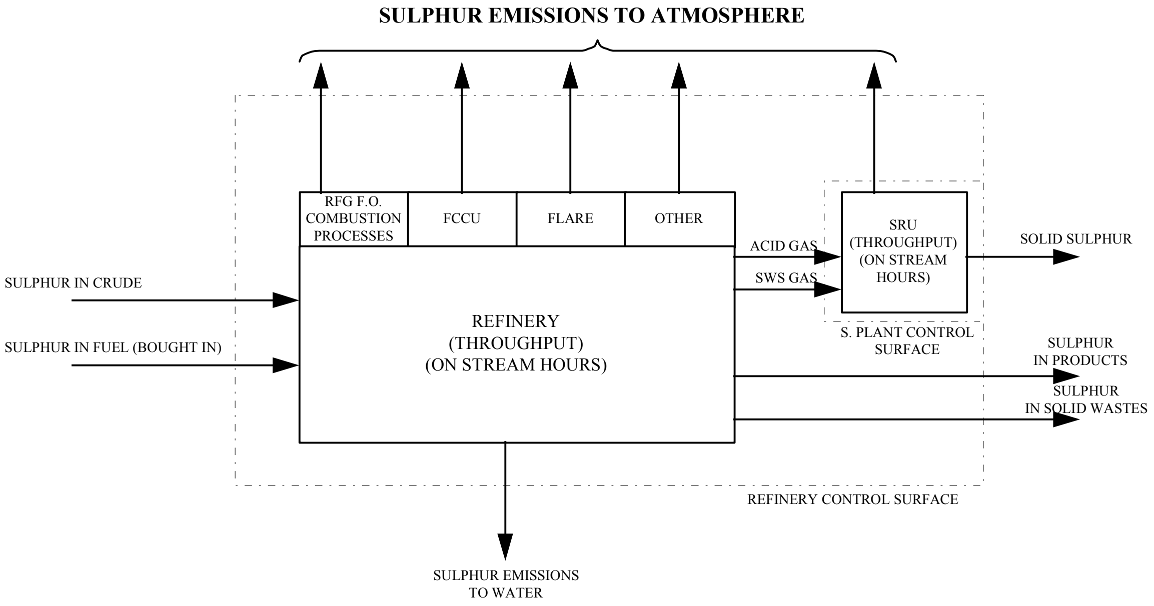
Hydrotreatment, in addition to removing sulphur compounds, will remove nitrogen compounds by about 15% to 40%. (Very severe hydrotreating might achieve higher percentage removals.) The nitrogen compounds, especially in residues used as fuel oil, give rise to increased levels of NOx when the fuel is burnt. However, as was identified above, installation of hydrotreatment purely for the purposes of refinery pollution abatement could be considered as excessive cost. This therefore applies the more so for nitrogen compounds in residues, which in any case would only be reduced to a degree by hydrotreatment.

5.4.2 In furnace Abatement of NOx

Low NOx burners

Typically a 30% to 40% reduction in NOx emissions can be achieved by fitting conventional low NOx burners. These burn the fuel on a staged basis to achieve lean combustion and hence lower flame temperature and lower NOx levels. Low NOx burners designed for firing refinery gas typically achieve 100 mg NOx/Nm^3 at 3% excess oxygen. NOx abatement on older furnaces and boilers may also be less effective due mainly to the need to avoid flame impingement on the furnace tubes.

New ultra-low NOx burners can, depending on combustion conditions outlined below, achieve 80 mg/Nm^3. They are currently available from two suppliers. Performance of ultra-low NOx burners in both natural draft and forced draft heaters are described below.



NOTE : DATA REQUIRED FOR EACH STREAM IS MASS FLOW RATE AND MASS FRACTION OF SULPHUR IN THE STREAM.

FREQUENCY OF REPORTING SHOULD BE MONTHLY AND OVERALL REPORT YEARLY

Figure 5.1 Data for refinery sulphur balance and SRU performance analysis

In the case of natural draft heaters, 80 mg/Nm^3 is achievable with ultra-low NOx burners when air preheat is below 150 °C (air preheat for natural draft heaters is unlikely to be above 150 °C) and when the burner is fired with a typical refinery fuel gas containing about 50% hydrogen. If the hydrogen content were to increase above 80% then NOx would increase. However, this level of hydrogen is not very likely in an oil refinery's fuel gas system. Slightly higher NOx emissions occur when firing natural gas with cold air, typically about 100 mg/Nm^3 . If the burner is fired on natural gas and air is preheated to 150 °C, then NOx levels are likely to rise to 115-120 mg/Nm^3. Fire box temperatures above 900 °C will also have quite an effect on achievable NOx levels; the amount of increase depends on the fuel specification, the heater dimensions and hence the heat liberated per unit volume.

In the case of forced draft heaters, 80 mg/Nm^3 is again achievable with ultra-low NOx burners when firing on refinery fuel gas. Emissions of NOx do increase if air preheat temperatures increase above 150 °C, if the hydrogen content goes above 80%, or if there are elevated fire box temperatures.

For natural gas firing with ultra-low NOx burners in forced draft heaters, NOx emissions will typically be 100 mg/Nm^3 . Again NOx will increase under the conditions described above.

Generally, natural gas firing with ultra-low NOx burners in both forced or natural draft conditions may show signs of instability at some points, particularly at low turndown and low excess air. Care needs to be taken during the installation of these burners. Burner testing to explore the limits of combustion prior to site installation is highly recommended for reliable operation.

To date, no low NOx burners have been developed for burning residual fuel oil which give NOx values as low as those from gas firing, since NOx arises not only from the combination of nitrogen and oxygen at high temperatures but also from the nitrogen compounds in the liquid fuel. Firing low NOx burners with fuel oil containing 0.3% wt nitrogen will typically produce about 450 mg/Nm^3 of NOx, this being from both thermal NOx and from the nitrogen compounds in the fuel. A typical 0.02% ash in the fuel gives rise to 50 mg/Nm^3 particulates, comprising about 20 mg from the ash and 30 mg as carbon produced from combustion. However, at turndown and when firing fuel oil with high ash, nitrogen and asphaltenes present, the NOx can rise to 700-800 mg/Nm^3 and carbon particulates will also increase.

For oil firing there is a direct link between NOx and particulates, i.e. a reduction in NOx as the flame temperature falls will lead to an increase in particulates. For low NOx fuel oil burners, as with conventional fuel oil burners, further reduction of thermal NOx results in an increase in carbon particulates.

Gas v. oil firing

As an example of the relative potential for gas and oil to generate NOx, in one UK refinery in 1996 approximately 42 000 tonnes of fuel oil was combusted producing 360 tonnes of NOx, whereas firing 130 000 tonnes of refinery gas produced about 350 tonnes of NOx, a ratio of about 3:1 in favour of gas. NOx factors (NOx produced per tonnes of fuel combusted) used by some refiners to report NOx emissions indicate NOx from oil firing to be two to three times that from gas firing. However, factors from other refiners, particularly those based on stack monitoring, indicate that NOx from oil can be as much as five or six times that from gas.

The amount of refinery gas combusted by refineries compared with residual fuel oil, in terms of megawatts fired, is typically 60% refinery gas to 40% fuel oil. However, data from the Public Register for 1996 show that, on some refineries, the amount of fuel oil fired can approach 60%.

If there were to be a significant increase in the amount of residual fuel oil burnt on refineries, possibly because of the predicted increase in surplus fuel oil and the likely decrease in refinery gas available, then NOx emissions have the potential to rise significantly. Even if the sulphur in the fuel oil were to be reduced to a very low level in order to reduce emissions of SO_2, the amount of NOx produced would remain high, relative to that achievable by gas firing, even if low NOx burners were fitted. This is due to the present lack of a suitable, similarly effective, low NOx fuel oil burner compared to low NOx gas burners.

Other NOx reduction processes

Using recirculated flue gas as part of the combustion air can further reduce NOx formation but the process is difficult to control especially during turndown, and the necessary plant modifications would be likely to incur excessive cost. Therefore using recirculated flue gas is not considered appropriate for refineries.

Control of NOx in gas turbine combustors is carried out by using low NOx burners and/or steam/water injection. However, steam or water injection and flue gas recirculation have not been applied to boilers and furnaces on UK refineries due to the technical difficulties, cost and the preferred solution of using low NOx burners.

Costs for reburnering a typical crude oil furnace with low NOx burners consisting of 40 forced draught burners would be approximately £2 million. This would include the general upgrading of the furnace air, fuel and control systems likely to be carried out at the same time by a refiner.

5.4.3 Downstream Flue Gas Abatement of NOx

A number of licensed selective catalytic reduction (SCR) processes are available. NOx removal efficiencies are typically between 80% and 90%. The process operates on the principle of reducing NOx to nitrogen and water using ammonia over a catalyst, the ammonia being injected into the flue gas upstream of the catalyst. The catalytic reaction usually requires a temperature range of 260 °C to 600 °C in which to operate effectively. This means that the location of the catalyst in the flue gas system is important and may restrict its application in some cases. However, lower temperature SCR processes are now becoming available which will operate closer to a typical flue gas stack temperatures of about 100 °C. Pressure drop can be an important consideration as to whether SCR can be applied to a flue gas system. For this reason natural draft furnaces could probably not be fitted with it.

SCR is used extensively on power plant in Japan and Germany and on gas turbine plant in California in the USA. However, to date it has not been widely used on refinery plant although it has been successfully applied to an FCCU in Sweden.

Typical installed costs for SCR equipment for the range of flue gas flows listed in Table 5.2 are given in Table 5.3.

Thermal NOx reduction processes, sometimes called selective non-catalytic reduction (SNCR) are also available. These operate by injecting ammonia into combustion gases at temperatures ranging from 870 °C to 1100 °C. This high temperature requirement means this process is less likely to be applicable to refinery plant. However, it has been applied in Japan on an FCCU where a CO boiler provides a sufficient temperature window.

Wet NOx scrubbing has advantages including lower capital cost, if installed in conjunction with SO_2 wet gas scrubbing. A separate spray tower is usually required prior to the main SO_2 absorption spray tower. An additive applied in this extra tower oxidises the NO to NO_2 which is then absorbed with the SO_2.

5.5 Particulate Abatement

Particulate loads from refinery combustion plant are normally fairly low unless heavy residues are burnt. Particulate loads are highest from FCCU regenerators, where they can reach 200-600 mg/Nm^3 as coke fines. Particulates may be abated using a number of methods including electrostatic precipitators (ESP), bag filters and wet scrubbing, as already described above.

It is unlikely that bag filters would be favoured for refinery processes such as FCCUs due to their pressure drop, the potential for 'blinding' of the bags, the large plot space required and their inability to cope with upset conditions. A similar problem of bag blinding can arise from 'sticky' soot particles from boilers when burning fuel oil. Therefore, except where wet scrubbing is employed to remove both SO_2 and particulates, ESPs are likely to be the favoured abatement technique as they are best able to cope with upset conditions. Typically they should achieve about 50 mg/Nm^3 release, but it should be noted that recovery efficiency of dust from FCCU flue gas in ESPs may in certain cases be lower than expected due to the high and varying resistivity of the catalyst dust. Typical installed capital costs for ESPs for the range of flue gas flows set out in Table 5.2 are between £1 million and £3 million. As an alternative, the use of ceramic filters on cyclone underflow systems would also probably achieve about a 50 mg/Nm^3 release. Ceramic filters designed to filter the complete gas stream have not yet been installed on refinery FCCUs.

5.6 CCGT/CHP Facilities

A number of refineries have, or are currently installing, combined cycle gas turbine (CCGT) or combined heat and power (CHP) plant, designed to produce steam and power for the refinery. This is usually done to replace in whole or part old oil-fired boiler plant, to reduce operating costs and to decrease reliance on the National Power generators. Where this occurs the Environment Agency may wish to consider a refinery's emission levels, to the extent that substitution of power from the National Grid is taking place, hence reducing emissions from the power sector.

The fuel for this type of facility is usually natural gas from the National Transmission System (NTS). However, refiners are likely to investigate the possibility of also firing refinery gas as part of the fuel slate, thus potentially reducing the amount of refinery gas available for combustion in boilers and furnaces.

Most turbines require a particularly stable mix of fuel in order to be sure of flame stability and are basically designed to burn natural gas. Refinery fuel gas components can vary considerably, especially when surplus hydrogen is produced, such as when a hydrotreatment unit is temporarily shut down resulting in excess hydrogen being set to the fuel gas system. However, these problems can usually be overcome, up to a limit of about 70% hydrogen in the fuel.

5.7 VOC Abatement

Very little data exist on the Public Register regarding VOC releases, although returns are made to UKPIA by refiners.

Most VOC abatement/improvement is made by refineries on an ongoing basis and therefore it is difficult to cost this specifically. The Environment Agency may wish to consider asking refiners to make returns to them and to set annual targets based on continuous improvement. A number of refineries operate a LDAR system, though some do not. A system for monitoring approximately 3000 refinery components (primarily pump seals, valves in high liquid vapour pressure or gas services, and road/rail loading) is estimated to cost about £70 000 excluding modification of poorly-performing equipment and cost of labour.

5.8 Effluent Water Treatment

5.8.1 Minimisation of Wastewaters

Conventional refinery practice is to bring appropriate wastewater streams together and provide a common treatment plant. The size and complexity of such plant may be reduced by employing waste minimisation techniques and the treatment of certain difficult wastes at their source. In addition, these techniques may serve to remove problems of disposal of solids and/or gaseous emissions which would otherwise be formed during the wastewater treatment process. Waste techniques fall into three categories namely (listed in priority order) source reduction, recycling, and treatment, although recycling may also take place after treatment.

5.8.2 Source Reduction

For refineries, a typical source reduction technique would be the provision of facilities and training of personnel in housekeeping techniques to prevent accidental spillages and leaks or reduce the excessive use of water during cleaning activities. Also included in this category are energy conservation methods, improved effluent flow control, upgrading equipment and optimising operating conditions. This could include optimisation of sour water stripper performance to reduce the number of upsets at a particular refinery. The smoothing out of run-down from tankage to prevent 'peaks' of contaminants, such as phenols and sulphides which could kill the biomass in a wastewater treatment plant, and the segregation of clean and contaminated process streams, are further examples of source reduction techniques.

5.8.3 Recycling

Recycling and reuse of materials is exemplified on a refinery by the recycling of sour water stripper bottoms to the desalters. There is a tendency for pollutants, particularly phenol, to be reabsorbed by the crude oil depending on the operating pH.

5.8.4 Treatment

Wastewater treatment processes fall into three main categories as follows:

- Primary treatment

This consists of the simple separation of gross oil and solids content using techniques such as API separators and plate interceptors (tilted or corrugated).

- Secondary treatment

More advanced separation of oil and solids content using techniques such as flocculation, air flotation (dissolved or induced), sedimentation and filtration (gravity or pressure).

- Tertiary treatment

Treatment of residual and dissolved pollutants using techniques such as biological processes, aeration and final polishing.

A key aspect in the operation of treatment plant is the need for refineries to balance the effluent waters before they enter the wastewater treatment plant itself, and particularly upstream of the biological treatment stage. This could help to eliminate excursions from discharge consents caused by process upsets which, at worst, could kill off the ‘bug’ population in the bioplant.

There may be need for pretreatment of a very strong waste stream upstream of the effluent treatment plant, such as a sour water stripper waste stream, or spent caustic from sweetening operations.

Four types of spent caustic arise from these types of operations.

- Sulphidic spent caustic from sulphide and mercaptan removal operations such as LPG prewash.

- Phenolic spent caustic from treatment of FCCU product hydrocarbons such as FCCU gasoline. This includes the removal of acid oils (cresols and xylenols), organic acids and phenols.

- Naphthenic spent caustic from the treatment of kerosene and diesel cuts.

- Chloride spent caustics from the removal of chlorides and pH control techniques.

Release of these types of streams directly into the effluent treatment plant may cause a number of problems including the release of mercaptans and hydrogen sulphide gases and associated odours at the wastewater treatment plant. These problems can be resolved by pretreatment of these streams.

All refineries in England and Wales use primary treatment processes. Most are now employing secondary and/or tertiary treatment to improve the final effluent quality.

5.8.5 Future Situation

Toxicity testing

From information obtained from the Public Register and from conversations held with IPC Inspectors, the underlying trend is for the tightening of discharge standards for oils and oxygen demand (COD, TOC, BOD) in the UK. It is therefore anticipated that refineries without biotreatment will need to install it in the near future. Wastewater treatment requirements will also be influenced by the introduction of direct toxicity assessment (DTA) techniques in the UK. A large pilot study is currently under way to assess a revised protocol for using DTA as a technique for water quality management. The intention is to use DTA on a prioritised basis to help improve receiving waters where toxicity is perceived to be a significant contributory cause of poor water quality. The current proposals address acute (short exposure) toxicity only. Tests for chronic (long exposure) toxicity may be developed in the long term. A number of the refineries have carried out ecotoxicological testing themselves, on current effluent discharges by methods such as Microtox. The new toxicity testing may only impact discharges to certain selected rivers/estuaries. Refineries that are affected may, depending upon the nature of their effluent, need to add final polishing, such as carbon filters, to their treatment schemes to achieve the required quality of discharges. These could consist of traditional GAC (granular activated carbon) or more unusual systems such as walnut or coconut shells.

Ammonia

A number of improvement notices have called for a reduction in ammonia discharge levels. Biological treatment will achieve the required reduction, but usually with an increase in nitrate levels. It is anticipated that future legislation may require the reduction of levels of nitrogen in discharges to certain receiving waters including the North Sea. This will probably mean that there will be a shift from legislating for nitrogen as ammonia to legislating for total (Kjeldahl) nitrogen. This may mean that the existing biotreatment systems currently used by some refineries may need to be upgraded or additional chemical treatment employed to convert the nitrogen further.

VOCs and odours

It is anticipated that future reductions in VOCs from refineries will encompass areas such as the wastewater treatment plant where long residence times in open ponds or API separators (separators designed to guidelines set out by the American Petroleum Institute) lead to potentially high levels of hydrocarbons and odorous gases being released. These are often a cause of complaint. A number of refineries in the USA and Europe use either floating or fixed covers on their API separators to minimise these emissions. The replacement of open ponds with storage tanks is recommended by the USEPA in their EPA Sector Notebook Project. The drive to reduce VOCs may also encompass the use of covers on flotation units. This may influence the selection of IAF (Induced Air Flotation) units above DAF (Dissolved Air Flotation) since the former are enclosed units. It should be noted that these units differ in their mechanism for removing impurities from the effluent. DAF units are generally held to be more efficient than IAF units. However, with a correctly-designed treatment scheme using biological treatment as the next step, little change in final effluent quality will be observed.

Oil in water testing

A number of different techniques exist for analysing oil in water, including the use of two or three peak infra-red analysis with or without filtration through Florisil. Results obtained using Florisil should not be compared with those that do not use this chemical during testing. Each technique will produce different measures of oil in water, particularly where there is a significant quantity of aromatics present in the effluent sample. Aromatic components would require treatment by biological techniques. It is recommended that data placed on the Public Register should include the test method and the determinants to enable meaningful comparisons to be made.

Estimated order of magnitude costs for abatement of wastewater releases are given in Table 5.3.

5.9 Summary of Costs of Abatement Plant

Table 5.3 summarises the estimated installed and operating costs for some of the abatement plant and techniques discussed above. They are battery limit costs based on 1998 prices and include such items as equipment, licence fees, foundations, erection, tie-ins to existing plant, and commissioning. They are an order of magnitude only. Site-specific factors such as layout, available space, and necessary modifications to existing plant could have a significant impact. In some cases these factors might be expected to increase the costs by some 50%.

Table 5.3 Summary of possible abatement plant capital and operating costs for refineries

	Abatement	Plant size range	Approximate capital cost (£million installed)	Approximate operating cost per annum (£million)
(a)	Upgrade of refinery amine treatment system to meet 0.01% to 0.02% v/v of H_2S in fuel gas	UK refineries	3-6 per refinery	(negligible increase in existing operating costs)
(b)	Wet flue gas scrubbing (SO_2 and particulate removal)	Flue gas flows 200 000 Nm^3/hr to 650 000 Nm^3/hr	6 12	1 2.5 (costs are mainly for caustic soda)
(c)	Reburnering of furnaces and boilers with low NOx burners plus upgrade	Crude oil furnace with 40 burners	2	N/A
(d)	SCR	Flue gas flows 150 000 Nm^3/hr 650 000 Nm^3/hr	3/5 8/14	0.5 2 (costs are mainly for ammonia)
(e)	Electrostatic precipitator	Flue gas flow 150 000 Nm^3/hr 650 000 Nm^3/hr	1.5 3.5	0.1
(f)	SRU including tailgas treatment unit (TGTU) to give >99% S recovery	50 t/d 100 t/d 250 t/d	10 15 28	New SRU operating cost approximately equal to existing costs
(g)	Tailgas treatment unit to improve SRU recovery to 99%	50 t/d 100 t/d 250 t/d	1.3 1.7 2.3	Operating cost relatively low
	99.8%	50 t/d 100 t/d 250 t/d	2.8 3.5 5.0	
(h)	Upgrade SRU with O_2 enrichment to increase throughput from 100 t/d to 170 t/d	100 t/d	1.7-4.5(2)	1.3 (costs are for oxygen)(2)
(i)	Use of LPG in lieu of fuel oil	As appropriate to each refinery	Small, some reburnering	Cost differential between LPG and fuel oil of £81 per tonne
(j)	Use of natural gas in lieu of fuel oil	As appropriate to each refinery	4 (for 10 km of 305 mm pipeline plus some reburnering)	Cost differential between natural gas and fuel oil of £32 per tonne
(k)	Use of 1% S fuel oil using typically atmospheric residue of North Sea crude in lieu of vacuum residue	As appropriate to each refinery	(Minimal)	Cost differential between atmospheric and vacuum residue approximately £63 per tonne
(l)	Installation of secondary and tertiary (biological treatment plant assuming API separators are installed(3)		8-10	
(m)	Installation of sand filters and carbon filters (for final effluent polishing)(3)		5	
(n)	Installation of covers on an API separator designed to handle 1135 m^3/hr effluent with 10 000 ppm oil and grease(3)		0.42	

Notes:

(1) Typical costs for hydrotreatment are provided in Table 5.1.

(2) Capital cost variation depends on complexity of installation and existing plant condition. Operating cost will vary depending on source of oxygen; cost given is for liquid oxygen purchased. Costs will reduce for leased oxygen plant and further still if a pipeline supply available.

(3) Reference used is the Guidance for Operators and Inspectors of IPC Processes, Effluent Treatment Techniques. Environment Agency, 1997.

6. POLLUTION REDUCTION STRATEGIES

6.1 General Considerations

This Chapter analyses a number of possible abatement options (strategies) that could be adopted by refineries for reduction of polluting releases. The options selected are based on the discussions in the preceding sections of this Review. The effective reduction resulting from application of each option is presented together with the economic cost of the option in terms of cost per barrel of oil processed per year by the industry. Capital and operating costs for abatement plant used in the analyses are those provided in Section 5.9.

There are also a number of abatement possibilities which deserve consideration but which do not form part of the abatement options considered. These are discussed in 6.1.1 to 6.1.5 below.

6.1.1 Hydrotreatment

The type of hydrotreatment an operator may select will be very specific to the refinery. As identified in 5.2.1 FCCU feed hydrotreatment would be a major and expensive part of any upgrade and therefore it is not seen as a strategy which can be reasonably applied solely for abatement purposes. Nevertheless, where refiners choose to invest in it to meet 2005 product specifications it would reduce releases of SO_2 from the regenerator by about 90%. Further, if the refiner chooses to combust the fuel oil from an FCCU complex which included a feed hydrotreater, it would also assist in reducing the sulphur content of the total fuel oil fired on the refinery.

Whatever type of hydrotreatment the refiner selects to meet the 2005 fuel specifications some increase in emissions will occur as the process requires significant energy inputs. The amount of increase in CO_2 from all UK refineries that will occur due to extra hydrotreatment has been estimated at between 2% and 4% of current levels depending on fuel fired.

6.1.2 Sulphur Balance and Sulphur Recovery

In Sections 3.3 and 5.3 it was noted that:

- A number of refineries are firing fuel gas which is in excess of 0.05% v/v sulphur. Amine treatment of refinery fuel gas will reduce the sulphur content. Hence low sulphur content refinery fuel gas ought to be achievable by all refineries at relatively low cost with the resultant lower SO_2 emissions, see Table 5.3.

- Gaseous overheads from SWSs are in some cases not being piped for processing to a sulphur recovery plant. In a few cases this stream may be very low in sulphur but in most cases it is expected to be significant and therefore sulphur recovery should be applied to these streams.

- Existing sulphur recovery plants in some cases exhibit operational problems such as lack of spare capacity, poor performance during turndown and poor reliability.

Best practice elsewhere in the world includes; firing of clean, very-low-sulphur fuel gas in furnaces and boilers; recovery of all sulphur-bearing gaseous streams; and highly efficient sulphur recovery units. Some UK refineries are already close to meeting these standards and in others improvements in this area are currently taking place. Others appear to be some way off meeting these best practice standards The lack of definitive data from the Public Register on sulphur balance information has meant that it has only been possible to make broad assumptions regarding existing sulphur abatement measures, especially related to sulphur plant performance. It has therefore not been possible to fully develop abatement options in this area. Advice has been given in Section 5.3, as to the data that refiners would need to supply to fully assess refinery and sulphur recovery plant performance. If this sulphur balance data were to be provided by refiners, the full effects on releases of carrying out improvement measures could be better assessed. Typical costs for potential abatement measures are given in Table 5.3.

6.1.3 Replacement with Low NOx Burners

This is ongoing and well advanced at most refineries although, as noted in Chapter 4 not all refineries have low NOx burners installed in all their combustion plants or have plans to retrofit them. Because of this wide variation in application, low NOx burner installation has not been analysed as part of the abatement options although typical costs for furnace reburnering are given in Table 5.3.

6.1.4 Liquid Effluent Pollutants

As already noted, the data available from the Public Register are limited in terms of both the number of sites reporting mass release data and the determinants reported. Where data are given, there is no explanation of assumptions that have been made, making it difficult to analyse and compare data. It has therefore not been possible to develop meaningful liquid effluent abatement options/strategies for refineries as a whole. Section 5.8 includes information of current practices, trends, costs and likely abatement requirements regarding effluent discharges.

6.1.5 Current Emission Limits

Data from the Public Register indicate that 1996 release limits are in some cases considerably higher than actual releases, particularly in the case of emissions of SO_2. While there may be good reasons for this, it is calculated that if refineries were to operate closer to these limits, a potential increase of 103 082 tonnes per year of SO_2 and 16 549 tonnes per year of NOx could occur. However, any revised limit levels would need to take account of a number of factors including a refinery's complexity, particular processing scheme, and current crude and product slates.

In this connection, all UK refineries in 1996 were processing North Sea crude oil to a greater or lesser degree and are expected to be processing it for the foreseeable future. If refiners subsequently wished to process sourer crudes, for example because they become cheaper, a view could be taken that they should install the extra abatement necessary, rather than have a limit level that automatically permits this.

However, in this type of situation the Environment Agency should be aware of unfair advantages which might result from any across-the-board reductions in limit values closer to the level of current emissions. For example, in the case where heavy high sulphur crude becomes cheaper those refineries which do not already process heavy crudes would have to install abatement plant to remain within the tightened emissions limits. Refineries which already processed in part heavy, high sulphur crude would have no incentive from their revised limits to improve abatement and they could more readily take advantage of the reduced price for heavy, higher sulphur crudes.

6.2 Options for Reductions of Releases to Air

Initially four possible pollution reduction strategies, or options, were evaluated for the effect they would have on emission of pollutants and their cost to the refineries. Although each one provided significant abatement none, of them met the requirements of forthcoming legislation from the EU, covering new National Emission Ceilings which are based on the COA. The requirements of this EU legislation are markedly more demanding when compared with EU Directives currently in force. A fifth option was therefore developed with the aim of meeting the requirements of this future legislation. Consequently this fifth option represents a step change from the four options initially developed.

Typical costs for installation and operation of plant and equipment needed to implement each of the options across the UK refinery sector have been estimated based on the cost data given in Table 5.3. Capital costs for each abatement option have been amortised over a five- year period. Annual operating costs for the corresponding option have then been added to give the total abatement cost per annum for each refinery. This figure has been divided by the annual nominal crude oil throughput of the refinery sector to give an abatement cost for the UK industry per barrel of oil processed by it as a whole. The total effectiveness of each abatement option across all refineries has been evaluated.

Note that in order to assess the costs and effectiveness of each abatement option for the UK refinery sector as a whole it has been necessary to make similar individual assessments for each refinery and then to aggregate each one. The data for individual refineries are not included in this Review document.

It should not be assumed that each option can necessarily be applied to every refinery. There may be good practical reasons, known only to the refiner, why certain options cannot be undertaken. However, it is considered that on the whole each option would be practical on most UK refineries and overall would generally cost the sums of money indicated.

Each of the five options is described below.

Option 1 Reduction of sulphur in fuel oil

This option entails the reduction of the sulphur content of fuel oil fired in combustion processes to 1% sulphur or less. This level is in line with an EU draft Directive 97/0105 (SYN) (although, as currently drafted, the Directive will not restrict sulphur content in fuel oil fired in refineries or large combustion plant on the basis that flue gas abatement is assumed by the EU to be applied in lieu and to be more cost effective (see Section 2.2.5)).

This reduction of the sulphur content of fuel oil would reduce emissions of SO_2. The degree of reduction would mainly depend upon the amount of fuel oil currently fired and also the actual fuel oil sulphur content. In this respect the sulphur content of fuel oil for UK refineries ranges from 0.4% to 2.9%. The proportion of fuel oil being fired varies from 20% to 75%, with one refinery not firing fuel oil at all. Similarly, fuel gas sulphur content ranges from 0.05% to 0.56%, with the percentage of fuel gas fired varying from 25% to 100%. One UK refinery fires almost all fuel gas and therefore this has not been included in the analysis of Option 1. Another refinery fires fuel gas with an elevated sulphur content but already meets the 1% sulphur in fuel oil; in this case the sulphur reduction in the refinery fuel gas has been considered in lieu of the fuel oil sulphur reduction. Two other refineries are already meeting the 1% sulphur in fuel oil and therefore are also not included in the analysis.

In order to evaluate a cost per barrel for implementing this option it has been assumed that 1% S fuel oil can be attained by firing North Sea atmospheric residue in lieu of vacuum residue. However, each refinery may have different means of attaining 1% sulphur or less in fuel oil. The approximate cost differential between these two types of oil is shown in Table 5.3 and this cost has been used in the calculation.

Option 2 - Substituting fuel oil firing with LPG or natural gas (NG)

Maintaining fuel gas firing and substituting fuel oil firing with either liquefied petroleum gas or natural gas would result in reductions of SO_2 and heavy metals, as both sulphur and metals are essentially zero in these fuels. Reductions in CO_2, NOx and particulates would also result for the reasons described in Paragraph 3.2.1.

As already noted, the difference in NOx production between fuel oil burners and gas burners varies and there are a wide variety of NOx factors currently in use for these fuels. This option has therefore used two estimates of the reduction which might be achieved by changing from oil to gas firing, namely a 2.5 times reduction and a 3.5 times reduction. These numbers therefore represent minimum and average reductions respectively. Any larger difference in NOx production potential would see greater benefits in NOx reduction from switching to gas firing. The evaluation also used the proportions of fuel oil fired on each refinery.

Costs accounted in this option are those resulting from diverting saleable LPG to combustion on the refinery (£131/t) and, alternatively, the cost of purchase of natural gas (£82/t) from the National Transmission System (NTS), less the cost of the fuel oil saved at typically £50/t. An interconnecting gas pipeline capital cost as shown in Table 5.3 has also been included for each refinery. Some of the refineries already have a connection to the National Transmission Grid; however, it has been assumed that the facility will need upgrading. Two refineries in South West Wales are a considerable distance from the NTS. As mentioned in Option 1, one refinery already fires almost entirely fuel gas and has not therefore been included in the evaluation of this option.

Option 3 - Abating key stacks on a refinery using wet gas scrubbing (WGS)

This option was applied to all UK refineries. Flue gas abatement has been assessed for key stacks on each refinery, typically combustion stacks and FCCU stacks. The stacks chosen were those with higher pollutant concentrations, flows and/or large fuel oil usage. Typically two stacks were selected for each refinery. It was not possible to check whether these selected stacks have the physical space around them to be able to install the clean up equipment, and this uncertainty should be regarded as a limitation to this option.

Wet gas scrubbing in twin absorption towers using caustic soda has been assessed, although other alkalis, e.g. $Mg(OH)_2$, could be used. It should be noted that although caustic soda is relatively expensive as a chemical, this system is flexible in terms of the wide range of applications with which it can be used and the multiple emissions that it can scrub. The system, suitably designed, will typically abate NOx by about 70%, SO_2 by about 90%, particulates by about 90%, and virtually all CO_2. It will also abate heavy metals to some degree through removal of particulates. Selenium, cadmium and mercury with higher vapour pressures would probably be less effectively abated than other heavy metals.

Wet gas scrubbing produces a water effluent which should be treatable in most existing refinery effluent treatment systems without the need for major expenditure to cope with the added load. Capital and operating costs used are shown in Table 5.3. The cost of the different sizes of plant necessary to handle the flow from various selected stacks was calculated using the cost estimating 6/10 rule Cost of new = Cost of known [throughput of new/throughput of known]$^{0.6}$

Option 4 - A combination of Options 2 and 3

The fourth option considered was a combination of Options 2 and 3, above. Fuel oil, higher than 1% S, would continue to be fired in the furnaces or boilers whose stacks were abated with wet scrubbing, but refinery gas supplemented with LPG or natural gas would be burnt in all other combustion units where abatement was not applied. Costs for this option are those used in Options 2 and 3.

At one refinery virtually no fuel oil is fired so that in this case, effectively, only Option 3 applies. For another refinery only the FCCU regenerator stack was selected for scrubbing. For this refinery Option 4 included the scrubbed FCCU stack only with all combustion plant being fired on gas.

Emission reduction effects under this option will be similar to those in Option 2 although SO_2 and particulate emissions will be marginally higher than in Option 2, and CO_2 and NOx emissions will be marginally lower.

Option 5

Option 5 has been developed with the aim of meeting the requirements currently set out in the EU's proposed Communication on Acidification (COA) and the Large Combustion Installations Directive (LCID).

Postscript

This proposed EU legislation has recently been modified as noted in Chapter 3.

In the development of this fifth option a number of points should be noted.

- It is assumed that if the COA and LCID were implemented as they currently stand that the refinery sector would be required to provide corresponding reductions from its operations. The extent of these reductions has been identified in Tables 2.5 and 2.7 of Section 2.6 after making the allowance for recent and prospective refinery closures.

- The emission sources covered by the proposed LCID constitute most, but not all, refinery releases to air. The COA would be applicable to all refinery releases. Therefore in developing a pollution reduction strategy that will broadly meet both these pieces of prospective legislation, the LCID was considered initially followed by the COA.

- In developing this option an assumption has been made that a small number of refiners may install FCCU feed hydrotreatment as part of their plans to meet the 2005 fuel specifications. As noted above, installation of FCCU feed hydrotreatment would significantly reduce SO_2 releases from this type of refinery unit.

- Costs of FCCU hydrotreatment have not been included as this investment would be primarily adopted to meet 2005 product specifications rather than for abatement reasons. At three refineries, modifications to the sulphur recovery system have been implemented since 1996. These costs have been included.

- On the basis of 1996 emissions data, closure of the Gulf, Llandarcy and Shell Haven refineries will reduce total sector NOx and SO_2 emissions by 11% and 13% respectively. Reductions for large combustion installations (taken as boilers, furnaces and gas turbines) for NOx and SO_2 emissions due to the closures will be 15% and 21% respectively. These closures mean that in order to meet the sector reduction requirements of the legislation total refinery emissions will need to be reduced by 89% for SO_2 and 63% for NOx, and that large combustion installations need to reduce 1996 emissions of SO_2 by 94% and NOx by 85%**.**

- As with Options 1 to 4, annual costs have been calculated on the basis of the combination of capital costs amortised over five years plus annual operating costs.

In order to achieve the high levels of emission abatement required for 2010 it has been estimated that the following is generally typical of the measures refiners would need to adopt to achieve the required SO_2 and NOx reductions.

(a) All combustion plant to be fired on clean (zero sulphur) gas with ultra-low NOx burners.

(b) SCR to be fitted to all major furnaces and boilers, subject to space and pressure drop limitations, as already discussed.

(c) Recovery of all waste gas streams containing sulphur for processing in the sulphur recovery unit.

(d) Sulphur recovery units operating at 99.9% recovery efficiency with spare capacity available during SRU shutdown.

(e) FCC feed hydrotreatment fitted to major FCCUs on two refineries, as part of plans to achieve 2005 fuel specifications, and wet gas scrubbing fitted to remaining FCCUs.

(f) Use of high integrity trip systems, in refinery process control operations and the recovery of waste gas streams, to minimise the frequency and quantity of releases from flares.

Based on the current level of abatement applied at UK refineries, together with data from the Public Register, it has been estimated that the abatement measures set out in Table 6.1 would provide the necessary reductions.

Table 6.1 Summary of typical abatement measures needed to be adopted by refineries to meet COA and LCID requirements

Abatement measure to be employed	Number of refineries needing to adopt measure
Natural gas firing and fitting SCR to combustion	7
LPG firing and fitting SCR to combustion	2
Hydrotreating FCCU feed	2
Scrubbing FCCU Regenerator emissions	6
Scrubbing Coke Calciner emissions	1
New SRU with TGTU	1
New TGTU	5
SRU modification to enable processing of streams from sour water stripper	1
Amine treatment of fuel gas	1

6.3 Results of Evaluation of Options

At each refinery, each option was evaluated for the percentage reductions in emissions it could provide and its cost of application. The range of reductions and costs shown reflect the spread of results for each refinery. These are shown in Table 6.2. It should be noted that in evaluation of the options, the accuracy of estimated % reductions reflects the reported data in the Public Register. Where data are neither reported nor estimated for a particular refinery release, the total emissions for that refinery will be smaller than the actual. The effectiveness of the abatement option in this case will therefore appear greater. Nevertheless, the major releases at each site are thought to be either reported or estimated as part of the Review and therefore the reductions shown in Table 6.2 are likely to be a fair representation of what could be achieved by each option.

Option 1

The application of Option 1, limiting the sulphur content of the fuel oil used to 1%, would result in a reduction in SO_2 emissions ranging from 19% to 64% depending on the refinery. Corresponding mass emission reductions of SO_2 vary from 2095 tonnes per year to 8283 tonnes per year. The costs for implementing this option to the refineries would typically range from £1.2 to £29 million per annum. This large range reflects the existing sulphur levels in fuel oil and the amount of fuel oil fired at each refinery. There would be little or no effect on releases of NOx, particulates or CO_2.

Option 2

Replacing fuel oil with natural gas or LPG in the combustion processes with refinery fuel gas continuing to be fired, would result in the following reductions:

- SO_2 - 16% to 92% - This large range between refineries reflects the variation in the amount of sulphur in the fuel oil and the amount of fuel oil fired in each refinery;
- CO2 - 12% to 38%;
- NOx - 16% to 52% using a NOx factor between oil and gas firing of 2.5.22% to 64% using a NOx factor between oil and gas firing of 3.5.

The NOx reductions achievable by switching from fuel oil to gas firing will depend very much on burner performance. They are calculated based on 1996, NOx emissions from the Public Register. Although combustion processes were fully reported in 1996 not all of the refineries have reported NOx emissions for petroleum processes, e.g. FCCUs. Reductions are therefore based on emissions from large combustion plant, and include some NOx emissions from FCCUs (approximately five out of eight refineries) and other non-combustion process plant where data were available. If all NOx emissions were provided in the Public Register the figures quoted for percentage reduction here would be slightly smaller. Particulate emissions also would be reduced with this Option 2 but insufficient information is reported for combustion processes to calculate the extent of the reduction.

Table 6.2 Ranges in % reduction of emissions and costs for each option

	Option 1	Option 2	Option 3	Option 4	Option 5
% SO_2 reduction	19-64	16-92	15-67	21-91	(2)
% NOx reduction (2.5)	n/a	16-52	3-47	29-57	(2)
% NOx reduction (3.5)	n/a	22-64	n/a	37-60	(3)
% CO_2 reduction	n/a	12-38	2-71	14-75	(3)
Cost £ million/yr(1)	1.2-29	0.8-18.6	1.1-6.95	1.1-15.4	6-31

(1) Annual costs are capital costs amortised over five years plus operating costs.
(2) In line with the requirements of the proposed Communication on Acidification and Large Combustion Installation Directive (see Section 2.6).
(3) Not developed.

Costs have been calculated for the use of natural gas or LPG as follows:

- substituting with LPG, additional costs range from £0.8 to £18.6 million per annum;
- if natural gas is used, total additional costs range from £0.9 to £4 million per annum.

The additional costs include for capital and operating costs as well as credit for the fuel oil not fired. The large range of costs reflects various amounts of fuel oil combusted on different refineries.

Option 3

For Option 3 wet gas scrubbing was applied to selected stacks serving, large fired heaters, steam raising plant, or FCCU units. In general, two stacks were selected for each refinery, except where there was not enough information available. Resulting refinery reductions ranged as follows, the actual reduction again depending on the refinery:

- SO_2 ranging from 15% to 67%;
- NOx ranging from 3% to 47%;
- CO_2 from 2% to 71%;
- particulates would be abated to some extent;
- the total costs for this option would typically range from £1.1 to £6.95 million per annum.

Option 4

The combination of Options 2 and 3 involves adding wet gas scrubbing to the same stacks as Option 3 and firing only gas in the remaining unabated stacks. Reductions range as follows:

- SO_2 reductions would be from 21% to 92%;

- NOx reductions as a minimum, would range from 29% to 57% using a NOx factor between oil and gas firing of 2.5 as an average. Using a NOx factor of 3.5 they would range from 37% to 60%;

- particulates would be reduced, less than Option 2 but more than Option 3;

- CO_2 reductions would be greater than Options 2 and 3 and would result in reductions from 14% to 75%;

- the total cost of this option with LPG would range from £1.1 to £15.4 million, and if natural gas was used from £1.1 to £9.9 million.

Aggregation of Options and likely best options 1 - 4 at each refinery

Table 6.3 shows aggregated costs and effectiveness across the refinery sector of applying each option at every refinery. It also shows, for the refinery sector as a whole, aggregated costs and effectiveness of selecting the most cost Effective of Options 1 to 4 (i.e. likely best option) at each refinery. In selection of the best option at each refinery, SO_2 emissions were the initial consideration. In cases where the costs were similar the lower cost option was selected.

Costs and effectiveness of the likely best option at each refinery were also aggregated to give optimal refinery sector abatement and corresponding cost per barrel of oil process by the refinery sector as a whole.

Aggregating the likely best option at each refinery gave a refinery sector SO_2 emission reduction of 64 040 tonnes per year, which represents a 52% reduction. The corresponding aggregated sector annual cost is estimated to be £26.4 million per year, equivalent to £0.04 per barrel of crude oil processed annually by the sector.

Table 6.3 Summary of aggregate refinery sector industry costs and emission reductions for each option

Footnotes for this table are on the following page		Option 1	Option 2(2)		Option 3	Option 4(2)		Aggregate of likely best options		Option 5
			LPG	NG		LPG	NG			
Cost of abatement	Capital cost (£ million)	1.2		40	95.7	104	120.8	47.9		450
	Operating cost (£million)	105.54	77.7	13.4	13.6	35	19	16.8		100
	Total cost per year(1) (£ million)	106.74	77.7	21.1	32.7	56	43	26.4		190
	Cost per barrel (£)	0.19	0.12	0.03	0.05	0.09	0.07	0.04		0.29
Reduction in emissions(3)	SO_2 (%)	31	48		37	49		52		}
	SO_2 (t/y)	37 549	58 915		44 876	60 172		64 040		}
	NOx factor used(4)		2.5	3.5		2.5	3.5	2.5	3.5	}
	NOx (%)	N/A	27	36	24	35	39	31	39	} (5)
	NOx (t/y)		8296	10 961	7097	10 606	11 786	9305	11 831	}
	Particulates (%)	N/A	33		36	42		48		}
	Particulates (t/y)		830		917	1082		1231		}
	CO_2 (%)	N/A	19		30	37		21		}
	CO_2 (t/y)		2 857 874		4 541 341	5 562 595		3 176 315		

Option 5

The total cost to the refinery sector of meeting the requirements of the COA and LCID, is £190 million, which is equivalent to a cost of £0.29 per barrel of oil processed by the sector.

Table 6.3 Basis of calculations

The following notes apply to the above table:

(1) Capital cost has been amortised over five years, hence total cost per year is annual operating cost plus one fifth of capital cost.

(2) Cost of LPG and NG has been discounted against the sale of the corresponding calorific value of fuel oil.

(3) Percentage reductions for each abatement option/strategy are based on 1996 releases.

(4) Different NOx reductions result from Options 2 and 4 depending on whether the factor for NOx emissions for fuel oil and gas firing is 2.5 or 3.5.

(5) Reduction in emissions provided by Option 5 are in line with the requirements of the proposed EU Communication on Acidification and Large Combustion

(6) Total crude oil processing capacity of UK refinery industry in 1996 was 90.3 million tonnes.

(7) Options 1 to 4 have been applied uniformly where data were available except as noted below:

- Option 1 applicable to eight of eleven refineries. Three refineries fire less than 1% sulphur content in their fuel oil currently;
- Option 2 applicable to 10 of 11 refineries. Currently one refinery fires almost entirely refinery gas;
- Option 3. wet gas scrubbing applied on all refineries;
- Option 4 applied at all refineries. One refinery fires no fuel oil, therefore Option 3 adopted as Option 4.

(8) At one refinery the FCCU stack is the stack selected for scrubbing, therefore in this case, Option 2 and 3 have been combined.

6.4 Implications for the Refinery Sector

The financial effects of implementing any of the above options/strategies can be measured against recent levels of profitability reported by the UK refinery industry. Figure 2.8 in Section 2.4.3 presents data prepared by UKPIA which illustrate the decline in overall refinery operating profitability among UKPIA member companies. The numbers are necessarily very general and include some impact from the retail sector. Nonetheless they do indicate the financial background against which the downstream industry is operating.

Table 6.3 shows the cost of implementing various emission reduction strategies on a basis of cost per barrel of oil processed for the refinery industry as a whole. It can be seen that Options 1 to 4 fall into the range between £0.03 to £0.19 per barrel of oil processed. Option 5 would have a much greater impact, costing £0.29 per barrel of oil.

The costs per barrel can be compared with profitability per barrel for the UK industry as a whole. Figure 2.8 in Chapter 2 represents data provided by UKPIA on the profitability of the UK refinery sector and its associated downstream and retail operations. It represents the most up-to-date information on the subject in the public domain. However, there are no separate data for the refinery sector without the downstream and retail operations included. The distorting effects of the Gulf War on UK refinery operations ceased in 1991 to 1992. Since then profitability of the sector as a whole fluctuated between a high value of about £500 million in about 1994 and a low value, essentially zero, in 1996. The amount of crude oil processed by UK refiners in 1994 was 93 million tonnes (approximately 1.9 million barrels per stream day). A very simple calculation is to divide the annual operating profit by the annual throughput, which in this case shows that the sector operating profit per ton in 1994 equalled £5.38. This is equivalent to about 72p per barrel hence, the implementation of these options 1 to 4 would result in a percentage impact of 4% to 26%. The implementation of Option 5 would result in an impact of 40%.

Clearly, the impact of zero profit in 1996 is that the industry in that year generated no surplus funds against which abatement costs can be compared.

It should be recognised that this economic analysis has been restricted to assessment of effects on the refinery industry. It has not considered the broader economic base, especially the upstream exploration and production sector of the operating companies which own the refineries.

6.5 Comparison with Legislation

In Chapter 3 it was noted that in 1996 UK refinery releases to air constituted approximately the following percentages of total UK releases:

SO_2	5.0%
NOx	1.3%
Particulates	0.8%
CO_2	2.6%

Table 6.3 shows Options 1 to 4 and the aggregate of likely best options of these options offering a range of percentage reductions in pollutant releases for the UK refinery industry based on 1996 emission levels, as follows:

Table 6.4 Aggregate of Best Options

	Options 1-4
SO_2	31% to 52%
NOx	24% to 39%
Particulates	33% to 48%
CO_2	19% to 37%

Note: the actual reduction % being dependent on the option selected.

These reductions can be compared with the requirements for reduction of releases in existing and prospective EU legislation (Note: the recent modifications to the proposed Large Combustion Installation Directive and Acidification Strategy is described in the Postscript in Chapter 3).

- The Large Combustion Plant Directive 88/609/EEC currently in force requires emissions for SO_2 to be reduced by 20% from 1998 to 2003. This would be achievable by the implementation of any of the options refinery-wide assuming no major increases in releases due to new plant.
- The emission ceilings proposed by the new Large Combustion Installation Directive for 2010 are likely to require a corresponding 94% reduction in SO_2 and 85% reduction in NOx of the refinery sector after making due allowance for known refinery closures. None of Options 1 to 4, nor the selection of the likely best options, would meet these requirements and further measures would be necessary such as those set out in Option 5.
- The Second Sulphur Protocol requires SO_2 emissions to be reduced by 80% by 2010 using 1980 as a baseline year. UK emissions of SO_2 reduced by 55% between 1980 and 1994, a trend compliant with the expectations of the protocol. It is not possible from the information available to ascertain what the UK refinery sector contribution to this trend has been. However, assuming they are generally in line with the trend, Options 1 to 4 could all deliver the refinery sector contribution to the further 25% reduction required by 2010.
- The Acidification Strategy for Europe requires a reduction in emissions for SO_2 of 89% and for NOx of 63% by 2010 when due allowance for refinery closure is taken into account. Assuming the 1996 refinery emissions are very similar to those of 1994, Options 1 to 4 would not achieve these reductions, and, as in the case of the Large Combustion Installation Directive, abatement measures such as those set out in Option 5 would be required.

6.6 Timetable for Implementation of the Options/Strategies

Typical timetables required by refiners to implement the various options would vary depending on the option as follows:

Option 1

Switch to 1% fuel oil. This ought to be achievable relatively quickly, typically six months to one year.

Option 2

(a) Fuel gas firing supplemented with LPG. As PG is present on almost all refineries this change should be achievable in one to two years. Time will be required for some burner changes and new piping.

(b) Fuel gas firing supplemented with natural gas. Some UK refineries already have a pipeline connection to the gas national grid system or are located close to it. Exceptions are the two refineries in South West Wales. Some upgrades of existing connections would probably be necessary for this option or also new natural gas pipelines installed. In this case implementation time would typically be two to three years.

Options 3 and 4

These include flue gas abatement and major new plant would be involved. Hence, implementation time for these options would be typically three years, due in some part to the need to engineer and construct the new abatement plant into an existing, and usually congested, refinery layout under operational conditions.

Option 5

The very significant investment that would be required to implement this option, such as the installation of SCR and FCCU flue gas scrubbing as well as the other measures described, will mean major forward planning would be needed by refiners. Overall they would probably need at least five years to implement the necessary measures.

7. LONGER-TERM STRATEGIES AND INFLUENCES

7.1 Introduction

The most likely long-term scenario for the oil refining companies is one of continuing struggle for market share against a crude oil price which is unlikely to rise significantly. The peak of oil and gas production world-wide will possibly occur around 2015 to 2020 and thereafter decline slowly. In Western Europe, although transport requirements are scheduled to increase, this is not likely to be reflected in a significant increased demand for fuels as the forecast increase in transport will probably be offset by increased fuel efficiency with the use of lean burn and fuel injection engines and other new types of technology. Therefore, overall product demand in Western Europe is likely to remain relatively flat for the foreseeable future.

Against this background there are a number of long-term issues that will directly or indirectly affect refinery operations in the foreseeable future. Some of these, such as sources and quality of crude supply, reductions in pollutant releases, increasingly stringent product specifications and declining fuel oil sales, have already been discussed for the short to medium term. This section discusses the longer-term effects of these issues as well as the implications for refiners of possible technological developments both inside and outside the refinery, which they will increasingly need to take into account in order to maintain their competitive position.

7.2 Sulphur Removal

If not removed in the refinery as elemental sulphur, sulphur in crude oil is released to the environment as SO_2 either in refinery emissions or in the case of fuel products through combustion at the point of use. Possible process technologies for the removal of sulphur, not already discussed in some detail, are described below along with their wider implications for refiners in the longer term.

7.2.1 Heavy Oil Gasification

During the crude oil refining process sulphur tends to be concentrated in the heavier, lower value fractions and products.

Heavy oil gasification can be applied to a wide range of low value oil products including:

- residual oils including vacuum residue, asphalt/pitch;
- petroleum/water emulsion including orimulsion and;
- petroleum coke.

The resulting products are virtually sulphur free and of increased value.

The process route typically comprises the following main steps.

- Gasification with oxygen and steam at 50 to 80 bar pressure to produce hydrogen, carbon monoxide, a smaller amount of CO_2 and hydrogen sulphide. This gas is usually called a ‘synthesis gas’ or syngas. The major processes available are licensed by Texaco and Shell. With minor exceptions, both these licensed processes can gasify all the heavy oils listed above. Oil gasification can be used as a very flexible ‘refinery dustbin’ to dispose of any residual heavy oil, refinery slops, etc. without limitation due to its metals or sulphur content.

- The ash and heavy metals in heavy oil are removed as solids and can be landfilled or perhaps sold for recovery of their high vanadium and nickel content.

- Hydrogen sulphide is removed by conventional amine scrubbing and the hydrogen- sulphide-rich amine sent to a sulphur plant for sulphur recovery. Typically 99% of sulphur in the feed is removed. New hot gas desulphurisation processes using absorbent solids are being developed which should be less expensive than amine systems.

The resulting gas, synthesis gas, comprising hydrogen and CO, is a very clean fuel that can be fired in furnaces or gas turbines, used for production of hydrogen, or for synthesis of a range of liquid fuels and chemicals. These may include liquid fuels with low sulphur through the Fischer Tropsch reaction, acetic acid, ammonia, methanol, and OXO alcohols. The gasification unit also produces export steam.

Experience from the USA indicates that a refinery previously combusting a high proportion of fuel oil in its furnaces and boilers improved its releases of SO_2, NOx and particulates by about 80% in each case after the installation of a gasification unit. At the same time the problem of disposal of surplus fuel oil has been solved.

If required, the CO can be converted to CO_2 via the CO shift reaction and the CO_2 removed, as described below in Section 7.6, leaving hydrogen as a fuel or as a processing component, e.g. for hydrotreatment or hydrocracking. Typical heavy oil consumption is 0.45 tonnes per 1000 Nm^3 of hydrogen produced.

Shell at its very large Pernis Refinery at Rotterdam in the Netherlands has recently undertaken a programme of major plant modernisation and investment which includes a residue gasification plant. The three gasifiers deliver hydrogen for a new large hydrocracker unit. As a result of this new unit part of the fluid catalytic cracking plant has been shut down as a proportion of transport fuels are now produced from the new hydrocracker. From the shift reactors the CO_2 is currently emitted to atmosphere. However, a project is in hand, funded by the Dutch Government, aimed at injecting the CO_2 into underground strata.

The main problem with investment in gasification plant is its capital and operating cost. To be attractive commercially it usually needs to be undertaken on a large scale. Typically, production of more than 200 MWe of electrical power is required through an integrated gasification combined cycle (IGCC) or else use of the products hydrogen, carbon monoxide and steam on a large scale to produce chemicals.

Generally accepted investment costs for an oil-gasification- based combined cycle plant in the 200+ MWe range are US$1200 to 1500 per kw installed, with a thermal efficiency of around 40% and about 99% sulphur emission abatement. As average electrical demand on a refinery is usually less than 80 MWe, investment in IGCC often depends on there being a market for the exported electrical power. However, high pressure steam can also be a valuable gasification product and there are examples of much smaller gasification units which make a good refinery fit.

In the current climate of very low UK refinery margins and low-cost natural gas, investment by a single refinery in IGCC for economic reasons seems unlikely in the immediate future, although co-operative ventures among refiners might be viable over the next few years. In the longer term, environmental pressures will help to encourage consideration of gasification as a way of disposing of residual fuel oil with a high sulphur content, as well as providing clean fuels for combustion in furnaces and boilers resulting in lower refinery releases. Gasification as a process is also more likely to be considered by refiners if the differential price between light North Sea crudes and heavier sourer crudes starts to widen so that processing a sour crude with gasification of residue becomes more economic. Other scenarios which would encourage residue gasification are: decline in North Sea oil production starts earlier than expected, or if legislation has the effect of reducing sales of fuel oil quicker than expected.

In the long term, 2010 and beyond, as sweet crudes start to decline, it seems likely that heavy oil gasification will be installed in a number of the larger refineries.

7.2.2 Solvent Deasphalting (SDA) and Combustion in a Fluidised-Bed Boiler

An alternative method for disposal of heavy residual oils or petroleum coke is combustion in a fluidised-bed boiler with limestone injection for sulphur capture. About 90% of the sulphur content of the fuel is captured and about 50% of the calcium in the limestone is used in sulphur absorption. The resulting calcium sulphate and unconverted calcium oxide, together with the nickel and vanadium, in the fuel are discharged from the boiler as a solid residue which can be used as road aggregate or disposed of to landfill. A combination of fluidised- bed boilers with upstream solvent de-asphalting or delayed coking can be a cost-effective solution for refineries with existing FCCU capacity and steam/power deficiencies. However, such schemes have a lower sulphur capture performance than gasification and they do not provide the option of producing hydrogen. There could also be environmental objections to the mining and transport of limestone and disposal of the residue. For these reasons gasification may be generally more attractive in the long term.

7.3 Oxides of Nitrogen

As already identified, NOx levels in flue gases from combustion will be lower generally when burning a clean gas than when burning a fuel oil because it is more difficult to achieve staged mixtures of air and oil close to stoichiometric proportions, and due to the nitrogen compounds present in the fuel oil. The only exception to this is when burning hydrogen gas which gives a considerably higher flame temperature than, for example, natural gas, leading to slightly higher NOx levels than those from natural gas. In the absence of downstream abatement, lower NOx levels will only be achieved by either burning clean gas on a more or less exclusive basis without downstream abatement, or by burning liquid or solid fuels with downstream abatement, typically SCR.

Even with the use of clean gas, SCR downstream abatement, as is currently practised in California may eventually be required in order to achieve ultra-low NOx release levels on a refinery.

7.4 Particulates

The technology and processes are well established to abate particulates to relatively low levels at costs which are not normally excessive. However, submicron particles are more difficult to abate. The firing of clean fuel gas will eliminate particulate releases from combustion plant. With the application of continuous improvement to the levels of particulate releases, as well as the application of the best abatement technology, it should be possible to eliminate particulates as a problem in the foreseeable future.

7.5 Volatile Organic Compounds (VOCs)

VOC reduction programmes such as leakage detection and repair (LDAR), waste minimisation and recycling are available to refiners. In addition the following abatement plant and techniques can be applied:

- vapour recovery systems, for example, during the loading and unloading of higher vapour pressure hydrocarbons;
- minimisation of flare releases through, for example, the use of high integrity trip systems for the control of process operations;
- closed loop product quality sampling and testing;
- application of latest seal technology for pumps, compressors and tankage;
- disposal of occasional vents and safety valve releases by flare or incineration; and
- vapour recovery from effluent treatment plants (not yet implemented on UK refineries).

With the application of such measures VOC releases from refineries should be reduced to levels which have only a minor environmental effect. It is unlikely, however, that VOC emissions can be eliminated altogether, even in the longer term.

7.6 Carbon Dioxide Releases

Assuming refinery utilisation gradually increases (as discussed elsewhere in this Review) and that product specification and abatement requirements continue to be more stringent, then CO_2 releases, if unabated, are likely to continue to rise since these measures will require energy. Within 2.2.1 the implications for refinery CO_2 emissions of increased processing to meet the 2005 product specifications are discussed. It has been estimated, as part of this Review, that to meet these specifications CO_2 emissions would increase between 2% and 4%, depending on the fuel type, due to the additional energy required.

A number of options exist for the reduction of releases of CO_2, including the following.

7.6.1 Combustion of Fuels with a High Hydrogen Component

The combustion of hydrogen produces water with no production of CO_2. As the proportion of carbon in the fuel increases so the amount of CO_2 increases. This is demonstrated in Table 7.1 below.

It may be seen from Table 7.1 that for equivalent heat releases, natural gas produces about 40% less CO_2 than coal and about 20% less than fuel oil.

7.6.2 Capture of CO from Synthesis Gas

As noted above synthesis gas may be produced by gasification of heavy residues or by steam reforming of natural gas. The CO content of synthesis gas may be used in the production of chemicals such as methanol and other alcohols and acetic acid, or alternatively the CO gas can be reacted with more steam under pressure to produce O_2 and more hydrogen. The CO_2 is then removed by absorption techniques. The resulting hydrogen-rich gas may then be combusted. Investment costs with CO_2 removal would be much greater than for gasification without CO_2 removal, typically increasing in the range of US$300 per 600/kW installed for CO_2 removal from reforming of natural gas. Thermal efficiency would fall from around 60% for a conventional natural-gas-fired combined cycle plant, to around 50%

7.6.3 Removal of CO_2 from Flue Gas Streams

Wet scrubbing using caustic soda for the removal of SO_2/NOx will effectively remove CO_2 as a carbonate. It should be noted, however, that to apply wet gas scrubbing for the sole purpose of removal of CO_2 would be largely self-defeating as the scrubbing process itself requires energy as does the production of the scrubbing agents. A number of other licensed processes are available which will remove CO_2 from flue gases using a solvent that can be recycled, typically methylethylamine (MEA). After absorbing the CO_2 in a scrubbing system, the solvent is thermally regenerated, releasing the CO_2. This could then be compressed, liquefied and sent to underground disposal. Present indications are that the high energy requirements of this type of scheme will discourage its general use.

Table 7.1 Effect of carbon content of fuel on CO_2 releases

Fuel[(1)(2)]	Natural gas[(1)]	Light fuel oil[(2)]	Heavy fuel oil[(2)]	Coal[(2)]
kg C/kg fuel	0.75	0.85	0.856	0.76
kg CO_2/kg fuel	2.77	3.11	3.14	2.78
Low Heating Value (LHV) (MJ/kg)	50	41	40	30
kg CO_2/GJ (LHV) of Fuel	56	76	78	93

(1) Natural gas is assumed to be 95% methane, 3% ethane and 2% propane by volume.
(2) Data from Spiers: Light and heavy fuel oil compositions plus NCB Coal Rank Grade No. 301 as national washed smalls as fired.

For the permanent disposal of CO_2 it would be necessary to find a suitable geological reservoir to avoid its rejoining the atmosphere. This option is currently being investigated by Shell at their Pernis Refinery in Rotterdam, by certain other major operators such as Statoil, in respect of offshore oil production and the International Energy Agency (IEA).

7.6.4 Coking

Carbon can be removed from residue oils using a coking plant. This is a well-established refinery process in the USA. Carbon (coke) is produced as an end product while lighter gas oils are also produced. It is worth noting that currently around 70% of high sulphur US fuel grade coke is exported to Europe for combustion, usually in power plant fitted with flue gas desulphurisation facilities.

7.6.5 Hydrogen from the Electrolysis of Water

Electrolysis of water produces hydrogen which can be used as a combustion fuel without CO_2 production. However, since significant power is required to electrolyse water, this is only likely to be an option where there is access to a cheap local source of electricity such as from a hydropower plant. Further, hydrogen itself is a difficult fuel to handle and combust safely as it has a very wide explosion range, poor flame stability under ranges of turndown, and high flame temperature. For these reasons hydrogen is usually burnt with other gases, such as methane and ethane to improve the combustion properties. The storage and transport of hydrogen also requires special measures such as specially-designed flanges and fittings to prevent leakage which easily occurs due to the very small size of the molecule.

7.7 The Emergence of Fuel-Cell Technology and Effects on Refineries

The latest reported advances in fuel-cell technology are such that it may be practical for motor cars and buses to be powered by fuel cells. A few buses in Canada are currently under trial powered by fuel cells using a methanol feedstock/fuel. The fuel cell is potentially much more thermally efficient (about 80%) than the internal combustion engine, as it eliminates the Carnot Cycle which severely limits the thermal efficiency (about 40%) of current conventional engines. Due to this increased thermal efficiency and the clean fuels it requires, the fuel cell produces much lower emissions.

The cost of producing fuel cells has also been reduced significantly over recent years and certain motor car companies, as a result, are now planning to produce prototype cars powered by them. However, their likely market price and performance is still very unclear.

The typical fuel cell operates on the basis of a proton-exchange membrane whereby hydrogen atoms react directly with oxygen producing an electric current. Fuel cells, however, are easily poisoned by the presence of carbon monoxide and sulphur compounds. One of the main technological issues in relation to fuel-cell-driven transportation now lies with the provision of the hydrogen. Hydrogen itself is the ideal fuel but as noted above it is difficult and expensive to store and transport safely in sufficient volume, although techniques currently being developed such as adsorption onto carbon, are showing some promise.

The favoured solutions at present involve transporting the hydrogen as a component of either gasoline, methane or methanol. These fuels can then be partially oxidised and reformed on board the vehicle. First, carbon-monoxide and hydrogen are produced, then carbon monoxide is converted to carbon dioxide using a catalyst and finally hydrogen and carbon dioxide are fed to the fuel cell. The carbon dioxide takes no part in the production of the electricity in the cell. One of the main debates currently concerning fuel cell technology for transportation therefore centres on which fuel is to be used. The advantages and disadvantages of the three mentioned above are as follows.

- Gasoline has the advantage that the refineries and infrastructure are already established for its production and distribution. It has the disadvantage that it still contains sulphur which would need to be removed to levels much lower than even the new 2005 gasoline specifications in order not to 'poison' the fuel cell. This would be very expensive to achieve and involve much higher energy inputs, and hence carbon dioxide releases by the refineries, in order to achieve the very low sulphur levels required.

- Methane could be supplied as natural gas but there are probably not sufficient supplies of natural gas in the medium to long term to meet all the demands for it.

- Methanol can be produced by refineries from naphtha, natural gas or gasification of heavy oil components. The principal unit operations are gasification, removal of sulphur in the form of hydrogen sulphide, methanol synthesis over a catalyst and finally distillation to produce pure methanol. Both methane and methanol would contain almost zero sulphur but methanol has the disadvantage of being toxic at high exposure levels.

If methanol (or hydrogen, if the storage and transportation issue can be solved) were to be produced from heavy oil gasification this could potentially have several major advantages. For example a valuable product would be produced from an increasingly unwanted and low value heavy oil feedstock. With a suitable increase in capacity of the installed gasification complex sufficient synthesis gas could be produced to provide clean fuel for the whole of the refinery and any associated power plant, and hence also provide a significant reduction in SO_2 and particulate emissions.

At present, it seems unlikely that the fuel cell will have a significant impact on refinery operations before about 2005. However, if the technology does prove to be a technical and commercial proposition in the next few years, then the potential for all round improvement in releases to the environment from refineries and vehicle transport might be very significant. It is to be expected that a long changeover period, ten years or more, would occur whilst conventional internal combustion engines were being phased out and fuel-cell-powered vehicles were being introduced. However, the effect on refineries of producing the new fuel whether it be virtually zero sulphur gasoline, hydrogen, methanol or methane (natural gas supplies in the long term are not likely to meet the demand as noted above) would be major and require significant investment.

Once the changeover period was completed, it is conceivable that, if the established fuel was hydrogen or methanol, a refinery could be reduced to largely gasifying crude oil directly without many of the downstream units it currently needs and utilises.

7.8 Summary

As identified previously in this Report, the burning of clean gaseous fuels, especially fuels with a high hydrogen content, has many advantages including:

- virtually zero sulphur emissions;

- considerably lower NOx emissions compared with fuel oil combustion (excluding pure hydrogen);

- zero heavy metal releases;

- lower CO_2 releases;

- zero particulate releases; and

- little need for downstream flue gas abatement except possibly in respect of NOx if very low levels of release are required.

As an alternative to the combustion of natural gas or LPG, refiners could gasify residues and fire the clean synthesis gas. However, this is expensive and to be economically viable usually needs to be carried out on a large scale. In the current economic climate and taking into account the relatively low cost of natural gas in the UK, gasification of residues is not considered a strategy that a single refinery is likely to adopt on its own in the very near future. However, in view of the declining fuel oil market, particular refinery circumstances or joint co-operative ventures by refiners might make this option viable in some cases in the longer term.

To remove CO and hence CO_2 from the products of gasification prior to their combustion would increase the cost of the resulting fuel (mainly hydrogen), and under prevailing economics would not be viable.

In the next few years at least, the best option for reduction of CO_2 release on a large scale seems likely to be the combustion of fuels with a relatively high hydrogen to carbon ratio such as hydrogen itself, natural gas or LPG. In addition the adoption, where practical, of heat integration, and combined heat and power (CHP) schemes to increase thermal efficiency will help to reduce CO_2 releases as will increased use of certain non-fossil-fuel alternatives, for example, solar power.

The introduction of the fuel cell, should it prove economically and technically feasible in the next few years, would have a major effect on refineries and considerably assist in reducing CO_2 and other polluting releases from transport vehicles.

8. CONCLUSIONS

The main conclusions of this Review are as follows.

- UK refineries are currently experiencing very low or negative profit margins and, until very recently, significant overcapacity. As a result, capital expenditure and operating costs have been and are being minimised by refiners. Further refinery closures or mergers are quite possible, although closing a refinery involves the spending of substantial sums of money in itself.

- The availability of light/sweet North Sea crude oil is helping to minimise expenditure that might otherwise be required to abate emissions and to achieve product quality. Most UK refiners now depend on light/sweet crude to meet current release levels and product specifications (for example, sulphur in gasoline and diesel). North Sea crude is also relatively easy to process and produces relatively large proportions of high value product. Refiners will continue to be dependent on it beyond the year 2000 when lower sulphur levels in gasoline and diesel will come into force.

- Light/sweet North Sea crude is likely to be available to UK refiners in good supply at least up to the year 2005 and probably beyond.

- By the year 2005 there will be a further sharp reduction in the permitted levels of benzene, aromatics and sulphur in gasoline and sulphur in diesel. To meet these new EU (2005) transport fuel specifications refiners are likely to need to undertake major new investment. Any significant abatement required should therefore be made known to the refiners as soon as possible as they are already considering plans and investment for 2005 fuel specifications.

- The combusting in refineries of ‘clean’ gaseous fuels has a number of advantages over liquid fuels, particularly heavy fuel oils. These include significantly lower SO_2, NOx, particulate, heavy metals and CO_2 emissions.

- Most refiners are likely to need to invest in some type of extra hydrotreatment to meet the EU 2005 fuel specifications. This extra hydrotreatment will require a corresponding amount of extra hydrogen which could be supplied from the refinery fuel gas system. This in turn may mean less refinery fuel gas is available to burn in furnaces and boilers. (The reduction in benzene levels in gasoline may also have the effect of slightly reducing the amounts of hydrogen produced by the reformer unit.) As a replacement for this loss of fuel gas, refiners may wish to burn more fuel oil which would, if unabated, lead to increased releases to air. The supply of hydrogen within their refinery is a subject operators will need to address as a result of the extra hydrotreatment.

- It has been estimated that the increased refinery processing required to meet the 2005 fuel specifications would result in UK refinery sector CO_2 emissions increasing by between 2% and 4%. UK Refineries currently contribute 2.6% to national emissions of CO_2.

- Discussions held with operators indicate that they generally have no plans for major investment prior to having to respond to the new EU (2005) fuel specifications. Operators were concerned to have clear targets/limits in respect of environmental releases which do not involve excessive cost to achieve and which are based on sound science, not on arbitrary reductions.

- Most refiners agree that disposal of higher sulphur fuel oil will become increasingly difficult, particularly as new limits on sulphur in fuel oil (1% max) are expected to be introduced by the EU. (However the draft EU Directive on this subject currently exempts refineries themselves and large combustion plant from this 1% fuel oil sulphur limit, on the assumption that equivalent abatement is carried out.)

- Compilation of an inventory of UK releases has shown total reported SO_2 releases from UK refineries to be about 120 000 tonnes per year with individual refineries typically emitting 7000 to 21 000 tonnes per year. This compares with some Scandinavian refineries, the most abated in the world, which typically have limits of about 2000 tonnes per year. The UK refineries range in capacity from 4.4 to 15.6 million tonnes per year of crude processed and the Scandinavian from 6.2 to 9.5 million tonnes per year.

- A review of world-wide refinery best practice and current abatement techniques on UK refineries has shown that UK refinery abatement practice does not compare particularly favourably with abatement in countries like the USA and the Netherlands, and is well behind Scandinavia and Japan.

- Review of the information from the Public Register shows that data concerning releases are incomplete in some areas. The

Environment Agency may, for example, wish to consider requesting a VOC release inventory and a sulphur balance from each refinery; something that a few refiners already supply. A number of other points concerning information missing from the Public Register have been raised in this Review, including some lack of data for sulphur recovery plants and sour water stripper gas streams. Further, information on solid waste disposal could be integrated into the IPC register and improvements in the uniformity of monitoring requirements for releases to water could be made.

- 1996 data from the Public Register show that some SO_2 and NOx emission limits for large combustion plant and FCCUs are well above 1996 reported release levels. There may be good reasons for this but it could mean that potentially-significant increases in current refinery releases to air could occur if refiners were to operate closer to these limits. However, any revised limit levels would need to take account of a number of factors including a refinery's complexity, particular processing scheme, and current crude and product slates. More complex refineries, particularly residue-upgrading refineries, generally require proportionally higher energy inputs and hence have proportionally higher releases than refineries with simpler processing schemes.

- Uses of FCCU hydrotreatment or hydrotreatment of residues, solely as an option to provide lower releases from the FCCU regenerator or lower sulphur refinery fuel oil, has excluded it on the grounds of excessive cost. However, hydrotreatment of the feed to the catalytic cracker, for example, may be included by some refiners as a processing unit in their plans to meet 2005 transport fuel specifications. Should this be the case then it would also assist in abating releases of SO_2 to air from FCCUs.

- Five options (or strategies) for reducing releases to air have been assessed. The first four involve: reduction in the sulphur content of the fuel oil fired; substituting fuel oil firing with natural gas or LPG; abating releases from stacks with large pollutant flows, and abating the same stacks, with all remaining combustion equipment being fired on fuel gas/LPG or natural gas. The fifth option involved assessing the abatement measures that would be required to meet the large reductions in pollutant levels required by 2010 under the Draft EU Large Combustion Installation Directive and the Communication on Acidification. Each of the five options have been evaluated for the UK refinery sector as a whole. There were insufficient data on the Public Register to develop abatement strategies for releases to water and land, though some guidance on measures to reduce impacts to these media have been provided.

- The first four options (or strategies) represent likely solutions that refiners could adopt to achieve significant reductions in releases to air. However, if required to achieve such reductions, individual refineries may well opt for various combinations of these options or other alternatives to suit their particular requirements. The fifth option represents an order of magnitude increase in pollution reduction and hence investment compared with the first four. It would involve almost all refineries burning clean gas, fitting selective catalytic reduction to remove NOx from combustion flue gas streams, scrubbing FCC flue gas and upgrading sulphur recovery systems and sulphur recovery plants. Certain other process modifications would also probably be necessary.

- The Options (or strategies) 1 to 4 give reductions for the refinery industry as a whole ranging from 31% to 49% for SO_2, 24% to 39% for NOx, 33% to 42% for particulates and 19% to 37% for CO_2, the actual percentage being dependent on the option.

- The aggregate of the likely best abatement option, selected from Options 1 to 4, for each refinery achieves a 52% reduction in SO_2 and 39% reduction in NOx. For this case Option 2 was selected as the best option for most refineries, though Options 3 and 4 were selected at refineries where gas supply was not available or where the refinery already fired almost entirely on fuel gas.

- The fifth option gives reductions in SO_2 and NOx in the order of 90% and 85% respectively.

- The cost of implementing each of Options 1 to 4 across the UK refinery industry, per barrel of crude oil processed by the industry, ranges from 3p to 19p. The industry aggregate cost of applying the likely best option, selected from Options 1 to 4, is 4p per barrel. The cost of implementing the fifth option is approximately 29p per barrel. Cost in this context is annual operating cost plus capital cost amortised over five years.

- Based on recent financial performance data provided by UKPIA for the UK refinery sector, profit margins were about 72p per barrel in 1994. Based on these data, implementation of Options 1 to 4 would represent between 4% and 26% of 1994 sector profits and Option 5 about 40%. However, with profits in 1995 to 1996 at almost zero, implementation of any of the options would be particularly significant on refinery sector margins in these circumstances.

- This economic analysis has been restricted to the refinery industry sector only. It has not considered the broader economic base of the operating companies which own or operate the refineries.

- The reduction in releases to air of SO_2 and NOx provided by the options indicate that commitments under the existing LCPD 88/609/EEC for SO_2 reduction could be met by implementing any of Options 1 to 4. The same is true of the UNECE Second Sulphur Protocol (1994). However, proposed new EU emission ceilings based on the COA and designed to be achieved by 2010 could be met only by the fifth option.

- In the longer term, gasification of heavy fuel oil residues produced by refineries is seen as a good solution to the disposal of high sulphur fuel oil and the provision of hydrogen. The clean syngas, hydrogen and carbon monoxide produced by this process could be burnt in furnaces or power plant resulting in much improved releases to air relative to fuel oil. The syngas can also be processed to extract the hydrogen for use in hydrotreatment with the carbon monoxide acting as a chemical feedstock. Gasification is an expensive process, both capital and operational costs are high, and it is therefore often best applied on a large scale, although there are a few situations where a smaller gasification unit can make a good fit in a refinery. Current economics, i.e. low refinery margins, relatively cheap natural gas, and good availability of low sulphur crude oil with little price differential compared to heavier crudes, all point to gasification not being installed by UK individual refiners in the near future. However, if crude oil price differentials start to widen significantly and refinery profit margins improve, or the market for fuel oil continues to deteriorate, then gasification may become economically viable for some refiners. Alternatively certain refiners might co-operate to construct a jointly-owned gasification facility.

- Reports of recent improvements in hydrogen/oxygen fuel-cell technology are such that vehicle transport powered by fuel cells may be technically and commercially viable in the next five to ten years. There are a number of options regarding the type of fuel used to provide the hydrogen for the fuel cell. Whichever type of fuel is preferred the long-term impact on refiners is likely to be significant.

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APPENDIX A1 - DESCRIPTION OF UK REFINERIES

A1.1 Conoco Refinery

Description

Conoco is currently wholly owned by DuPont although DuPont have announced an intent to dispose of some of its oil-related business. The refinery is located at South Killingholme adjacent to the Lindsey Oil Refinery. Operations began in 1969 and the refinery now processes about 140 000 bpsd crude (7 million tonnes per year) plus around 60 000 bpsd imported residues and gas oils. Conoco is unusual in being able to produce premium value 'needle' grade coke for anode manufacture. To make premium quality coke requires low sulphur, low metals, coker feed, the refinery consequently runs a mixed North Sea crude slate. The refinery is linked to the British Pipeline Agency pipeline network.

Refinery process units

The refinery is equipped with thermal cracking, catalytic cracking and two coking units. All these processes give the refinery processing flexibility and a low yield of fuel oil product.

A1.2 Gulf Milford Haven Refinery

Description (Post script)

This 115 000 bpsd (6 million tonnes per year) refinery which became operational in 1968. Gulf has sold to Texaco its interest in the jointly-owned Pembroke Cracking Company and the refinery site to Petroplus b.V. of Holland. This site no longer undertakes refinery operations.

A1.3 BP Coryton Refinery

Description

The refinery, which is owned by BP (70%) and Mobil (30%), is located on the Thames close to the Shell Haven Refinery. It began operation in 1953 producing a range of products including lubricating base oils, industrial fuels and bitumens. Current capacity is approximately 200 000 bpsd (7.5 million tonnes per year) of light crudes (predominantly North Sea) and imported atmospheric residue.

Refinery process units

The refinery has a range of units for the production of fuels and continues to be a producer of lube base oils.

The fluidised catalytic cracker unit (FCCU), propane deasphalter and lube train provide some residue upgrading capability. However, the refinery still produces a quantity of fuel oil.

A1.4 Elf Oil (GB) Milford Haven Refinery

Description

Elf Milford Haven is a relatively modern, ex-Amoco refinery, dating from 1973, and is owned by Elf and Murco. It is located on the north side of the Haven.

The refinery processes a sweet crude slate, predominantly from the North Sea, and has a nominal capacity of 108 000 bpsd (5.4 million tonnes per year). Atmospheric residue is imported in order to fully load the FCCU.

The refinery is connected to the shared pipeline system for the distribution of finished transportation fuels to the Midlands and North West England.

Refinery process units

The refinery is equipped with an FCCU but has no fuel oil upgrading/conversion process units.

A1.5 BP Oil Grangemouth Refinery

Description

Grangemouth Refinery dates from 1924 and is now owned by BP (70%) and Mobil (30%). The current capacity is 200 000 bpsd (8.7 million tonnes per year).

The refinery is linked by pipeline to the Forties Oilfield and to the Finnart Ocean Terminal on the Scottish west coast. Crude processed is predominantly Forties, supplemented with imports of crude and residue through Finnart.

The refinery is a supplier of feedstock to BP Chemicals located next to the refinery.

Approximately 120 MW power is raised in the refinery's own power plant from fuel oil firing, supplying both the refinery and the adjacent chemicals site.

Refinery process units

Grangemouth has both FCCU cracking and hydrocracker units for vacuum gas oil conversion, but currently has no processes to upgrade/convert fuel oil. A hydrofiner produces low sulphur diesel fuel.

A1.6 Esso Fawley Refinery

Description

Fawley, 100% owned by Esso, is located on the west shore of Southampton Water and competes with Shell Stanlow as the largest refinery in the UK. Nominal refinery capacity is 300 000 bpsd (15.6 million tonnes per year). Operations at the site began in 1921, but it was not acquired by Esso until 1949. In 1966 Exxon Chemicals started up a petrochemical complex adjacent to the refinery. The refinery is highly integrated with the petrochemicals facility.

The refinery has pipeline connections to Fawley power station for fuel oil supply and to terminals in London, the Midlands and North West England.

Refinery process units

The refinery is equipped with catalytic cracking and residue hydrodesulphurisation (Residfiner). The Residfiner began operation in 1991 and upgrades vacuum residue feed to lighter products, FCCU feed and low sulphur fuel oil. Lubricating oils are also produced at Fawley.

The refinery processes both North Sea and Middle East crudes.

A1.7 Shell Haven Refinery

Description

The Shell Haven Refinery is currently scheduled for closure before the end of 1999. A significant number of process units came on line in the early 1950s upgrading the site to a conventional oil refinery. It is a 100% owned Shell facility located on the Thames estuary at Stanford-le-Hope, Essex, and has a current capacity of 4.3 million tonnes per year.

Crude processed is predominantly North Sea. The refinery delivers products by road and sea and is connected to the White Oil British Pipeline Agency pipeline serving the Midlands and East Anglia.

Refinery process units

The refinery has no FCCU, although a hydrocracker unit was added in 1979 and an isomerisation unit (for light naphtha octane improvement) in 1992. Except for a small bitumen plant the refinery has no bottom of the barrel upgrading capacity.

A1.8 Mobil Llandarcy Refinery

Description

Operations at the Llandarcy site in South Wales began in 1921. The refinery ceased crude oil processing in the early 1980s as part of BP's refining rationalisation programme. Since this time the refinery has imported atmospheric residues, principally from North Sea crudes to feed retained lube oil and bitumen production facilities. Following the recent BP/Mobil downstream merger the refinery was operated by Mobil until it ceased production in November 1999.

A1.9 Lindsey Oil Refinery

Description

The Lindsey Oil Refinery, located on the Humber Estuary, is jointly owned by Total Oil (GB) Limited and Fina plc. Refinery capacity is 200 000 bpsd (10 million tonnes per year). Lindsey is able to process both sweet and sour crudes from all over the world. In addition to road and rail, distribution from the refinery is linked to the UKOP pipeline connecting central and southern England. The Lindsey Oil Refinery is located next to the Conoco Refinery.

Refinery process units

Multiple process units, including FCCU, visbreaking and bitumen production provides flexibility and ability to process sour crudes.

A1.10 Shell Stanlow Refinery

Description

The 100% owned Shell Stanlow refinery is located at Ellesmere Port, Cheshire, and is adjacent to petrochemical, manufacturing and research facilities. Operations at site began in 1924 with the installation of crude storage and blending facilities and bitumen production. Refinery capacity is now 262 000 bpsd (13 million tonnes per year). The refinery processes predominantly low sulphur crude, but Middle East crude is imported for lubes production. Pipeline links exist to the Ince 'B' Power Station, the Shell petrochemical complex at Carrington, near Manchester, Haydock terminal and the UKOPL pipeline to the Midlands.

Refinery process units

The refinery is equipped with an atmospheric residue catalytic cracker and a lube oil train. Both these plants help reduce the refinery's fuel oil production.

A1.11 Texaco Pembroke

Description

The refinery opened in 1964 and is 100% owned by Texaco, located in Dyfed, South Wales. Refinery capacity is a nominal 190 000 bpsd (9 million tonnes per year). The refinery also operates a nearby cracking facility (the Pembroke Cracking Company), this became 100% Texaco owned when the nearby Gulf Refinery closed.

The refinery processes crude from many countries, including the Middle East and Africa, but the principal feed is North Sea. The refinery has fuel oil pipeline connections to the Pembroke Power Station and transportation fuel pipelines to the Midlands and Manchester.

Refinery process units

The FCCU and Visbreaker allows the refinery to run a sour crude slate if it wishes. Visbreaking apart the refinery has no residue upgrading plant.

A1.12 Phillips Imperial Petroleum

Description

This hydroskimming refinery began operation in 1963 and is owned by ICI/Phillips Imperial Petroleum Limited. Nominal crude capacity is 100 000 bpsd (5 million tonnes per year). The refinery processes North Sea crude (Ekofisk) from the oil terminal at Seal Sands. Naphtha is transferred to ICI by pipeline. The adjacent ICI facility also receives fuel oil from the refinery.

Refinery process units

A hydroskimming refinery. No processing of atmospheric residue, which is sold to other UK refineries mainly as a low sulphur fuel oil.

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APPENDIX A2 - BRIEF LAYMAN'S GUIDE TO OIL REFINERIES

Crude oil

Crude Oil from an oilwell is a mixture of liquid and gaseous hydrocarbons. The mixture will vary considerably from oil field to oil field. For example, the proportion of short-chain hydrocarbons and hydrocarbon gases may be higher in one type of crude oil than another. Refineries normally are designed to process particular types of crude oil.

If this is the case the crude oil is normally termed 'a light crude'. Conversely if the crude contains a higher proportion of tar and pitch, it is usually called 'a heavy crude'.

Another important factor is the amount of sulphur that occurs in the crude oil. Crude oils with less than about 1.5% to 2% Sulphur by weight are termed 'sweet crudes'. Those with a larger amount of sulphur are termed 'sour crudes'.

Typical components of crude oil from the oil well include:

- methane (with smaller amounts of ethane) - this is also called natural gas, most of this is removed at the oilfield;
- propane and butane - once liquefied by cooling termed liquefied petroleum gas (LPG) and sold under various brand names such as 'Calor Gas';
- paraffins - straight-chain hydrocarbons;
- naphthenes - multicyclic hydrocarbons which may be saturated or unsaturated;
- some aromatics - unsaturated cyclic rather than straight-chain hydrocarbons;
- water - this is usually largely separated from the oil at the oilfield before the oil is transported to the refinery.

Condensate

A very light portion (or fraction) of hydrocarbons from an oil well, usually liquid at lower temperatures, which are intermediate between propane/butane gas and heavier liquid hydrocarbons. Condensate normally includes hydrocarbon molecules with between 5 and 7 carbon atoms present in each molecule.

Crude Oil Slate (diet)

Crude oils from around the world vary in cost and in the proportions of the types of hydrocarbons present in each crude. Depending on the products an oil refinery wishes to produce and the cost of each crude, it will choose a particular crude oil or combination of crude oils for its refinery that best suit its requirements. The particular combination of crudes an oil refinery selects is termed its slate or sometimes, its diet.

The role of the refinery

The characteristics and components of the fuels and other products, such as lubricating oils, produced by an oil refinery vary considerably. The specification that each fuel, such as gasoline (petrol), diesel and aviation fuel, is required to meet is very precise and detailed. It is the task of the refineries to process crude oil to ensure that their products conform to these specifications and that the quantities of the various fuels and other products produced meet market demands. This is achieved through physical and chemical refining of crude oil as described briefly below.

Refining:

(i) Crude & Vacuum Distillation

The first main process unit on a refinery is the crude distillation unit (CDU). This separates the various components of the crude oil by making use of the different boiling points of the various hydrocarbon components of the crude. The CDU is often supplemented by a vacuum distillation unit (VDU) which further distills the higher boiling point hydrocarbons under vacuum to minimise thermal breakdown. The products produced by the CDU and VDU would not normally be in the quantities and to the specifications required. There is normally a surplus of higher boiling point hydrocarbons, the longer chain or larger molecules, and a deficit of lower boiling point or shorter-chain molecules.

The other processing units on a refinery are therefore designed to take the products from the CDU and to convert and treat them to the quantities and the specifications required. In most cases, this treatment produces a range of products including the desired component as well as some gaseous hydrocarbons and heavier residues. Almost all of these treatment and conversion processes are of proprietary designed and are licensed by refiners.

(ii) Cracking

Some of the processes downstream of the CDU are designed to break the longer or larger molecules into smaller ones. The term used in the refinery industry for the breaking of larger hydrocarbon molecules into smaller ones is 'cracking'. This type of process usually involves the use of a catalyst and/or high pressure; hence the term 'cat cracker' - i.e. a cracking process using a catalyst. One of the most common cracking processes on a refinery is a 'fluidised catalytic cracker unit' (FCCU). This operates on the basis of catalyst being suspended in a turbulent mixture of hydrocarbon and hydrocarbon vapour. The FCCU is the main process unit for the production of gasoline on a refinery.

(iii) Hydrocracking
This is a high temperature, high pressure cracking process, principally designed to produce good quality distillate fuels such as diesel and aviation fuel from heavier (higher boiling point) poorer quality feedstock. The process is very flexible, however, and can produce a wide range of essentially zero sulphur products including gasoline.

(iv) Reforming
Another important refinery process is ‘reforming’. This produces, amongst other products, ring-based hydrocarbons (aromatics) from the straighter chain molecules. These improve the precombustion or ‘knock’ properties of gasoline (petrol) when blended into the gasoline pool. One ring compound which is increasingly being removed from gasoline is benzene due to carcinogenic concerns. Other ring compounds such as xylenes and toluenes are also sometimes removed as feedstocks for the petrochemical industry.

(v) Isomerisation and alkylation
Branched chained hydrocarbons also have better ‘anti-knock’ properties than straight-chain hydrocarbons. This characteristic is important for petrol ignition engines. Various refinery processes are designed to produce branched chains hydrocarbons, these include such process units as isomerisation and alkylation.

(vi) Visbreaker
This is a mild thermal cracking process designed to break longer chain (heavy) hydrocarbons into shorter or lighter hydrocarbons. The main objective of the process is to lower the viscosity of the resulting fuel oil product. If this was not done more valuable middle distillate would have to be added to the fuel to meet viscosity specifications. In the process, the heavy oil is heated in a furnace under carefully controlled conditions of temperature and pressure. The resulting ‘cracked’ oil is then distilled to produce the lighter products and lower viscosity fuel oil.

(vii) Synthetic fuel/gas
Synfuel: The product of synfuel (short for synthetic fuel) is based on syngas, see definition below, which is processed to produce a liquid fuel. There are a range of synfuels including methanol, but the term is generally used for fuels produced via the Fischer Tropsch process. The resulting liquid is extremely low in sulphur and has excellent properties as a fuel for internal combustion engines. As a result emissions are considerably improved compared to a standard refined fuel.

Syngas: Short for synthesis gas. Synthesis gas is a mixture of carbon monoxide and hydrogen. It can be produced by the reforming of carbon, including coal, or hydrocarbons. Various process routes are available based on reaction with steam and/or oxygen. Sulphur can be removed before or after reforming depending on the process.

(vii) Bottom of the barrel processes
The ‘heavy’ (high boiling point) black residues that remain after vacuum distillation can be further treated to produce more valuable ‘lighter’ or lower boiling point products. What remains after these processes have been applied is usually asphalt/pitch or even petroleum coke (carbon). Processes to refine these heavy black residues include, visbreaking, and coking, solvent deasphalting and residue cracking. Alternatively, the heavy less useable hydrocarbons can be gasified to produce synthesis gas (hydrogen and carbon monoxide), and in turn power fuels or chemical feed stocks.

Sulphur removal
Sulphur in fuels leads to the emission of sulphur dioxide when the fuel is burnt. Therefore a number of processes on a refinery are designed to reduce the sulphur in refinery products as much as possible. Sulphur removal processes have a number of names and include hydrotreatment, hydrodesulphurisation and hydrofining.

DOW Sulferox
This is the proprietary licensed process to remove hydrogen sulphide from gas streams by contacting with a liquid which chemically absorbs the sulphur. The liquid yields elemental sulphur upon regeneration with air in a sparged tank. The process differs from other recovery processes in that sulphur is recovered in an elemental form without combustion. The process has an economic capacity range which places it between fixed bed absorbents and Claus type processes. Another licensor of a similar process is US Filter.

Sulphur Recovery plant
When sulphur is removed from hydrocarbon products or feedstocks it is normally produced in the form of hydrogen sulphide gas (which smells of rotten eggs at low concentrations). This gas is recovered and is then piped to the sulphur recovery plant which converts the gas to elemental sulphur. With modern technology, 99% or more of the sulphur fed to the sulphur plant can be recovered.

Flaring
When operating all the processes referred to above, there comes a point when it is no longer economic to recover small amounts of gases. In such circumstance these are piped to an elevated flare and burnt. The flare also acts as a safety system in case of a sudden need to discharge combustible gases.

Energy demands
Many refinery processes have large demands for energy, in the form of electrical power, for example for driving electric motors for pumps and compressors and in the form of direct heating via furnaces and indirect heating via steam. To make a refinery as economic as possible a large amount of heat and energy recovery is therefore designed into the processing units, most of which are 'heat integrated'.

Emissions to Air
Furnaces (fired heaters) and boilers for the production of steam result in the emission to air from the combustion of fuel fired in these types of facility. Emissions to air also result from fluidised catalytic cracking where carbon which accumulates on the catalyst is burnt off. Other processes such as coking can also have significant release to air. Leakage and evaporation of hydrocarbons when exposed to air results in release of volatile organic compounds (VOCs).

Effluent and Solid Wastes
As with all industrial processes, with liquid oily effluents and solid wastes are produced although compared with some other types of industrial processes the amounts of solid wastes per unit weight of products are relatively small. Facilities are provided to treat these effluent and wastes.

Offsites and Utilities
These are terms used in the refinery industry. Offsites include storage and handling, including loading and offloading of crude oil, intermediate products and final products. Offsites also usually include blending facilities, flares and buildings.

Utilities normally include the plant and equipment needed to provide such systems as steam at various pressures, power, nitrogen, air, fuel gas, water and effluent treatment.

Usually the offsites and utilities cover a larger plot area on a refinery than the processing units.

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APPENDIX A3 - GLOSSARY OF TERMS AND LIST OF REFERENCES

Glossary of Terms

AG	**Acid Gas**
API	**American Petroleum Institute**
AR	**Atmospheric Residue**
BACT	**Best Available Control Technology**
BAT	**Best Available Techniques**
BATNEEC	**Best Available Techniques Not Entailing Excessive Cost**
BBLS	**Barrels (1 metric tonne of crude North Sea crude oil is approximately equivalent to 7.5 barrels).**
BPSD	**Barrels per Stream Day**
BOD	**Biological Oxygen Demand**
BP	**British Petroleum**
BPEO	**Best Practicable Environmental Option**
CDU	**Crude Distillation Unit**
CCGT	**Combined Cycle Gas Turbine**
CFB	**Circulating Fluid Bed Boiler**
CFH	**Catalytic Feed Hydrotreater**
CH_4	**Methane**
CHP	**Combined Heat and Power**
CO	**Carbon Monoxide**
COA	**Communication on Acidification**
COD	**Chemical Oxygen Demand**
CO_2	**Carbon Dioxide**
CONCAWE	**Conservation of Clean Air and Water in Europe - The European Oil Industries Organisation for environment, safety and health protection**
CPI	**Corrugated Plate Interceptor**
DAF	**Dissolved Air Flotation**
DTA	**Direct Toxicity Assessment**
EC	**European Commission**
EEC	**European Economic Community**
EMS	**Environmental Management System**
ENEL	**Italian Electricity Utility**
EPAQS	**Expert Panel on Air Quality Standards**
ESP	**Electrostatic Precipitator**
EU	**European Union**
FCC	**Fluidised Catalytic Cracking**
FCCU	**Fluidised Catalytic Cracking Unit**
FGD	**Flue Gas Desulphurisation**
FGR	**Flue Gas Recirculation**
FSU	**Former Soviet Union**
FTAA	**Free Trade Association of the Americas**
GAC	**Granular Activated Carbon**
GQA	**General Quality Assessment Classification**
H_2S	**Hydrogen Sulphide**
HSFO	**High Sulphur Fuel Oil**
IAF	**Induced Air Flotation**
ICI	**Imperial Chemical Industries**
IEA	**International Energy Agency**
IGCC	**Integrated Gasification Combined Cycle**
IMO	**International Maritime Organisation**
IPC	**Integrated Pollution Control**
IPPC	**Integrated Pollution Prevention and Control**
kg	**Kilogramme**
kt/y	**Kilotonnes per year**
LAER	**Lowest Achievable Emission Rate**
LCP	**Large Combustion Plant**
LCPD	**Large Combustion Plant Directive**

LCID	**Large Combustion Installation Directive**
LDAR	**Leak Detection and Repair**
LPG	**Liquefied Petroleum Gas**
MTBE	**Methyl Tertiary Butyl Ether**
mg	**Milligrams**
MW	**Megawatt**
MWe	**Megawatts, electrical**
MWth	**Megawatts, thermal**
NAFTA	**North American Free Trade Area**
Nm^3	**Normal Metre Cube**
N_2O	**Nitrous Oxide**
NETCEN	**National Environmental Technology Centre**
Ni	**Nickel**
NO_2	**Nitrogen Dioxide**
NOx	**Oxides of Nitrogen**
NSPS	**New Source Performance Standards**
NTS	**National Transmission System**
OECD	**Organisation for Economic Co-operation and Development**
OPEC	**Organisation of Petroleum Exporting Countries**
RFG	**Refinery Fuel Gas**
ROCE	**Return on Capital Employed**
SCOT	**Shell Claus Offgas Treatment**
SCR	**Selective Catalytic Reduction**
SDA	**Solvent Deasphalting**
SEPA	**Scottish Environment Protection Agency**
SNCR	**Selective Non-Catalytic Reduction**
SO_x	**Mixture of sulphur dioxide and sulphur trioxide**
SO_2	**Sulphur Dioxide**
SO_3	**Sulphur Trioxide**
SRU	**Sulphur Recovery Unit**
SWQO	**Statutory Water Quality Objective**
SWS	**Sour Water Stripper**
SWSG	**Sour Water Stripper Gas**
TAME	**Tertiary Amyl Methyl Ether**
TAN	**Total Acidity Number**
TEOR	**Thermally Enhanced Oil Recovery**
TGTU	**Tail Gas Treatment Unit**
TOC	**Total Organic Carbon**
t/y	**tonnes per year**
UKOOA	**UK Offshore Operators, Association**
UKOPL	**UK Oil Pipelines Limited**
UKPIA	**UK Petroleum Industries Association**
UNECE	**United Nations Economic Commission for Europe**
UNECE/CLRTAP	**Convention on Long Range Transboundary Air Pollution**
USEPA	**United States Environmental Protection Agency**
V	**Vanadium**
VBR	**Visbreaker Residue**
VDU	**Vacuum Distillation Unit**
VGO	**Vacuum Gas Oil**
VOC	**Volatile Organic Compounds**
WGS	**Wet Gas Scrubbing**

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