report no. 00/54

impact of a 10 ppm sulphur specification for transport fuels on the EU refining industry

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Brussels
October 2000

ABSTRACT

Production of road fuels to a 10 ppm sulphur specification is feasible but costly both in terms of refinery investments and CO_2 emissions. Other fuel properties would not be significantly affected.

KEYWORDS

Sulphur, CO2 emissions, cost, diesel fuel, gasoline, LP model, energy consumption, refinery, oil industry

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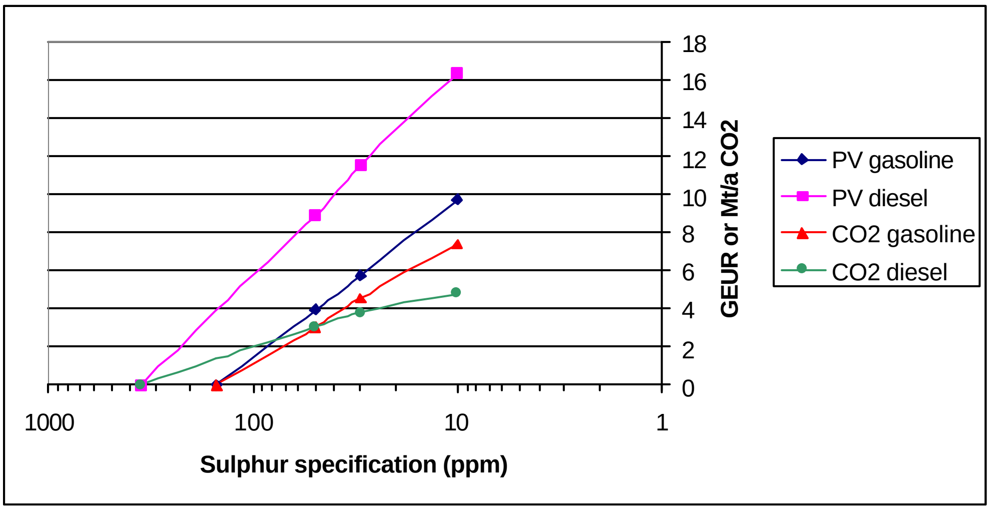
SUMMARY

In May 2000 the EU Commission launched a consultation on the need to reduce the sulphur content of petrol and diesel fuels below the level of 50 ppm already mandated for 2005 to a value of 30 or 10 ppm. In the context of its response, CONCAWE carried out this study to estimate the consequences for the EU refining industry in terms of additional costs as well as carbon dioxide emissions.

The study followed the established CONCAWE methodology whereby new product specifications are met by refinery investments while the projected demand is fully met.

The main conclusions of the study are as follows:

- Production of road fuels down to a specification of 10 ppm sulphur is feasible with already existing or emerging refinery technologies.
- Other fuel properties would not be noticeably affected with the exception of small reductions of the average olefins content of gasolines and polyaromatics content of diesels.
- The additional Present Value (PV) costs to the refining industry to reduce the sulphur limit for both fuels from 50 to 10 ppm would be in the region of 13.3 GEUR and the additional carbon dioxide emissions would represent around 6% of the total emissions of EU refineries. These figures are of a similar order of magnitude than those found in the context of Auto-Oil I to reduce sulphur from the current levels down to 50 ppm. The costs related to a 30 ppm limit would be around 4.4 GEUR. The figure below shows the cumulative costs and CO_2 emissions from the present sulphur specification down to the 10 ppm limit.



- Virtually every refinery would require new processing facilities. This would be likely to stretch resources and sufficient lead-time would be necessary to allow for orderly design, procurement, engineering and construction of the new plants.
- In reality, individual refiner's strategies could lead to under-investment and supply/demand imbalances.

1. INTRODUCTION

In May 2000 the EU Commission launched a consultation on the need to reduce the sulphur content of petrol and diesel fuels below the level of 50 ppm already mandated for 2005 to a value of 30 or 10 ppm.

In the context of its response, CONCAWE carried out a study to estimate the consequences for the EU refining industry in terms of additional costs as well as carbon dioxide emissions.

The objectives, methodology and results of this study are discussed in this report. Note that further modelling work was carried out after the submission to the Commission and the cost and CO_2 emissions figures published in this report are higher than those included in the submission. The conclusions are, however, not affected.

2. OBJECTIVES AND SCOPE

The objective of the study was to estimate the changes required in the EU-15 refining Industry to comply with a reduction of the road fuels sulphur specification from 50 to 30 or to 10 ppm while meeting the projected future EU-15 demand in terms of:

- New investments,
- Incremental operating costs,
- Incremental energy consumption,
- Incremental carbon dioxide emissions.

In addition the study aimed at estimating the impact of the sulphur reduction on other road fuels properties.

3. METHODOLOGY

The CONCAWE methodology for such studies has been described in detail in an earlier report (ref. 1). The main elements are highlighted below:

The first guiding principle for such studies is to ensure, wherever possible, that the effects of a change are studied at the exclusion of all other changes or, in other words, all else being equal.

Changes in product quality are achieved by investing in new facilities while meeting a constant demand and having access to an essentially constant feedstock slate. The necessary changes are absorbed by a single marginal crude oil. Methanol import is allowed for the manufacture of MTBE or TAME from otherwise refinery streams. MTBE import is also allowed. Suitably scaled grassroots investment costs of 400 MUSD for a 500 kt/a methanol plant and 350 MUSD for 500 kt/a for MTBE are then included in the total investment costs. Import/exports are not allowed beyond what is reasonably expected for the base case. Allowing fluctuations in demand, additional import/exports and/or major shifts in the feedstock slate would require a wide range of assumptions based on economic scenarios. Our approach, where supply and demand are essentially fixed, is transparent and the results are insensitive to such scenarios.

In reality a mixture of investment and trading options would be used. Such trading options would either be only temporary solutions or, if sustainable long-term, would be compensated in cost terms by changes in price differentials. In other words market forces would then ensure that the global cost remains more or less the same.

The starting point is generally the current state of the refining industry and a base scenario for future product demand and specifications. The base case aims at establishing the investments required to satisfy the base scenario. Introduction of a further requirement (e.g. a tighter specification) establishes an alternative case. The cost of the extra measure is then assessed as the differential between alternative and base case.

3.1. MODELLING

To arrive at the minimum required investment costs, CONCAWE uses a suite of models including a two-tier Linear Program (LP) and a spreadsheet-based model.

The first level LP model represents the EU-15 as seven regions[1] each having a single refinery with the aggregated capacity of all actual refineries in that region. A demand scenario is established for each region and a total EU-15 feedstock diet is fixed together with total EU-15 imports/exports of components and finished products. Networking possibilities between regions (and between refineries in each region) and transfer costs for components and product exchange are set on the basis of the actual infrastructure in place. The model then optimises the distribution of the available feedstocks between the regions.

The second level LP model represents each region separately in the form of four refineries with different configurations i.e. “Simple”, “Catalytic cracking” (CC),

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[1] SCA-Scandinavia (Denmark, Sweden, Finland), UKI-UK/Ireland, BEN-Benelux, GEA-Germany/Austria, FRA-France, SPP-Spain/Portugal, ITG-Italy/Greece

“Hydrocracking” (HC) and both CC and HC. Each refinery has the aggregate capacities of the actual refineries in that group. The feedstocks, component import/export and demand for each region are allocated according to the results of the first level model. Some product specifications are specific to a region (e.g. cold properties of gasoils). Each regional model is used to study the impact of e.g. a product specification change, starting from a base case.

The mass demand for gasoline is adjusted to reflect the different heating values of components. This refinement has so far not been included for diesel inasmuch as fluctuations are small. This may need to be introduced for future studies e.g. related to large changes in density.

The output of each regional model is analysed in a spreadsheet model in order to estimate the investment costs corresponding to the required plant capacity changes. One of the considerations is whether new plants are likely to be built in each refinery or whether a single large plant would be built in one refinery while more component exchanges would take place. The logic built into the model is the result of the Industry’s experience. Generally treating plants are not shared and are built in each relevant refinery. Costly conversion plants such as catalytic crackers or hydrocrackers are only economic with a sufficiently large capacity as a result of which the decision of one refiner to go ahead with such a plant will probably preclude investments in similar plants in the region unless/until sufficient demand is forthcoming.

3.2. TOTAL COSTS

The investment cost for the new plants is calculated on the basis of standard capital costs and suitable scaling factors. Costs associated to “external” plants (e.g. methanol imports) are also taken into account and so are extra operating costs such as those related to fuel additivation. Costs are expressed in money of 1998. The total cost to the Industry is expressed as a Present Value calculated with simplifying assumptions. The capital is deemed to be expended in one single year and the new plants have an economic life of 15 years. The present value is expressed in money of the year in which the capital is invested. Constant yearly operating costs are incurred to which a real-terms 7% discount rate is applied. According to these assumptions and in line with a practice initiated during the first Auto-Oil programme, the present value of the operating costs is calculated by multiplying the yearly figure by a factor of 9.75. The resulting Present Value (PV) is then calculated as:

$$\text{PV} = \text{Capital cost} + 9.75 \times \text{Annual Operating cost}$$

Costs are expressed in US Dollars in the model and have been converted into Euros at an exchange rate of 0.95 EUR/USD.

3.3. CARBON DIOXIDE EMISSIONS

The extra carbon dioxide emissions relevant to a specific change are calculated on the basis of the incremental global carbon input required to achieve that change i.e. essentially extra energy usage which translates into extra intake of crude oil and other feedstocks. The figures therefore include all consequences of the desired change on the operation of the refineries as well as compositional changes of the fuels. They do not take account of any improvement of the end-use efficiency enabled by the quality change of the fuel.

4. BASE CASE

This study was based on a demand scenario for the year 2010, meant to represent the period 2005-2015. This scenario was used throughout the Auto-Oil II process and is based on pre-Kyoto forecasts obtained from the EU Commission. Some modifications were made to the original EU data to incorporate the views of the Oil Industry, the main one being an increase of the diesel volumes compensated by a decrease of gasoline volumes. The regional and total EU-15 "call on refineries" are summarised in **Table 1**. More details, including the actual supply/demand balance in 1998 can be found in **Appendix 1 and 2**. The total EU product demand remains essentially unchanged from the current value (some 625 Mt/a) although individual product demands vary significantly. There is growth for all road fuels and particularly for diesel and jet fuel. Heating oil and heavy fuel oils regress.

Table 1 EU-15 and regional call on refineries 2010 (Mt/a)

	SCA	**UKI**	**BEN**	**GEA**	**FRA**	**SPP**	**ITG**	**EU-15**
Gasoline	9.2	29.9	10.6	27.3	19.2	14.9	21.7	**132.8**
Jet/kerosene	2.0	14.5	7.3	8.6	5.9	5.9	5.7	**49.9**
Diesel	8.7	21.1	16.3	25.9	22.3	24.0	36.8	**155.1**
Other Gasoils	8.1	5.0	11.0	28.9	13.5	5.0	8.2	**79.7**
Fuel oil	5.5	9.6	2.3	5.7	9.3	8.9	14.2	**55.5**
Others	3.4	13.7	28.8	20.9	17.0	19.8	23.8	**127.4**
Total	**36.9**	**93.8**	**76.3**	**117.3**	**87.2**	**78.5**	**110.4**	**600.4**

Note: The figures include international bunkers but exclude refinery fuel and loss as well as some 40 Mt/a of chemicals feedstocks, LPG and petroleum coke not considered as call on refineries, e.g. supplied directly as crude condensate or direct imports.

Within the main product categories, grade volumes are adjusted for each region to reflect the Industry forecasts (e.g. for 98 RON super-gasoline).

The base case road fuels specifications are those currently mandated for 2005 in the EU (**Table 2**). The road fuels sulphur specification is therefore 50 ppm, reduced from the current values of 350 for diesel and 150 for gasoline.

Table 2 Base case critical road fuels specifications

Product		Gasoline	Diesel
Sulphur	ppm	50 max.	50 max.
Density	kg/m^3		845 max.
Total Aromatics	%vol	35 max.	
Cetane Index			46 min.
Cetane number			51 min.
T95	ºC		360 max.

It is generally recognised that North Sea production will slowly decline, particularly from older fields while newer fields tend to yield more naphthenic crudes (light, low sulphur but with high density). The crude oil slate available to EU refiners will slowly shift to more naphthenic low sulphur crudes and overall to heavier, more sulphurous crudes. This trend is incorporated into the crude slate deemed to be available in 2010 (**Table 3**). It must be noted that the crudes mentioned are to be regarded as generic crudes meant to represent the typical quality of crudes from a certain origin. This simplification, essential to limit the scope of the modelling work, is considered to be acceptable for this type of study.

Table 3 Current and projected EU-15 crude slate (Mt/a)

			1998	2010
Slate composition		%m		
Category	*Proxy crude*			
Low sulphur light	Brent		52	28
Low sulphur light naphthenic	Nig. Forcados		8	16
Medium Sulphur	Iran Light		13	20
High sulphur heavy	Kuwait		27	35
Condensate	Algerian		0	2
Total		Mt/a	628	621
Average properties				
Density		d15/4	0.85	0.86
API gravity			34.9	33.5
Sulphur		%m	1.03	1.27
Atm. Residue yield		%moc	42.2	42.8

The investments required to cater for the changes of the demand, more stringent product specifications and the changes in the crude slate are incorporated into the base case.

5. ASSUMPTIONS AND MODELLING OPTIONS

5.1. SULPHUR TARGET

A distinction is made between product specifications and the actual levels required at the refinery gate to cover for possible contamination in the distribution systems and/or the reproducibility of the analytical methods. In order to guarantee a 10 ppm sulphur level at the pump, it is considered that refineries would have to produce at a level of 7 ppm. This was further reduced to 6 ppm for Spain and Portugal to recognise the importance of pipeline transportation in that area. Similarly a 30 ppm specification was deemed to require 25 ppm at the refinery gate. The base case specification of 50 ppm is deemed to translate into a 40 ppm market average.

5.2. GASOLINE

In previous studies most gasoline components of non-catalytic-cracking origin were considered sulphur-free. For the very low levels of sulphur considered in this study this had to be reviewed. Accordingly only reformates and isomerates are now considered as sulphur-free while, in line with experience, the sulphur content of other components such as alkylates is set at 3 ppm. The bulk of the sulphur remains of course in gasolines from catalytic crackers (FCC gasolines) and from various returns from petrochemical plants.

Sulphur removal from FCC gasolines with minimum octane loss and olefins saturation has been the subject of much research in recent years and a large number of processes are currently in various stages of development. A number of options are available in the model for processing of FCC gasolines and chemical returns. Details are given in **Appendix 3**. Although the scheme in our model does not incorporate all processes available, its flexibility is sufficient to arrive at realistic investment costs and product quality estimates.

In order to fully internalize all investments and CO_2 emissions, MTBE imports were not allowed beyond what is required in the base case. Methanol imports for internal MTBE production were, however, allowed.

5.3. DIESEL

The ability of conventional hydrodesulphurisation units to deliver very low levels of sulphur is strongly dependent of their original design particularly with regards to hydrogen partial pressure which has a major influence on both the ultimate level of desulphurisation achievable and the life of the catalyst. Another essential parameter is the heaviness of the feed as the heavier molecules are, as a rule, more difficult to desulphurise.

It is CONCAWE’s view that it is now possible to design a new single-stage hydrodesulphurisation plant that will produce gasoils with less than 10 ppm sulphur with a state-of-the-art but otherwise conventional desulphurisation catalyst operating at a total pressure level in the region of 65 bar. Noble metals catalyst systems are not required for this purpose. This has two major consequences.

> Firstly it implies that existing units can be retrofitted to produce ultra low sulphur products. As they generally operate at a somewhat lower pressure

> level and higher space velocities, this will be at the cost of a significant loss of capacity (the more so as the operating pressure decreases and the feed heaviness increases).
>
> Secondly it follows that deep desulphurisation can be achieved without large hydrogen addition that would lead to major changes to other gasoil properties such as density, aromatics and cetane number. Yield loss is also not significantly more than for base case desulphurisation.

The processing options for gasoil available in the model are shown in **Appendix 4**.

It must be realised, however, that such deep desulphurisation plants would need to reduce the typical feed sulphur level by three to four orders of magnitude. This would require a higher level of reliability than hitherto necessary especially as even a slightly off-target product could not be blended away for lack of any blending component with a lower sulphur content. Very small amounts of cross-contamination with other -high sulphur- refinery steams would also have immediate consequences on the quality of the ultra-low sulphur product. For these reasons our modelling includes a 7.5% desulphurisation over-capacity as well as costs for storage and reprocessing of 16 days of annual production. The details of this calculation are given in **Appendix 5**.

Although the bulk properties of the desulphurised gasoils would not be much affected, certain performance properties certainly would. This is particularly the case for lubricity, conductivity and oxidation stability, all of which are affected by the loss of most polar compounds that occurs during deep desulphurisation. This can, as a rule, be compensated for by extra additivation, the cost of which has been taken into account in our modelling.

6. RESULTS

By 2005 EU refineries will already have invested heavily to meet the 50 ppm sulphur specification as well as the 35% aromatics limit for gasoline mandated for that year. A further reduction to 10 ppm would be far from trivial and would require significant additional investments. It must be realised that, although small in absolute terms, the refinery product sulphur target would in fact be reduced by nearly one order of magnitude (from say 40 to 6-7 ppm), a major change in terms of e.g. catalyst performance.

Already commercially proven technologies make it possible to produce gasolines and diesel fuels with ultra low levels of sulphur with limited effects on either yields or other product properties. Emerging technologies will further improve on this. This is, however, at a cost both in terms of investments and of energy consumption and corresponding carbon dioxide emissions.

6.1. GASOLINES

Investments would be concentrated in refineries with a catalytic cracker and also in facilities that use chemical return streams. New plants would include splitters and various treating processes, a number of which are currently, either in the last stage of development or in the early phase of commercialisation. At this time there is no reason to believe that any of these processes will provide a genuine breakthrough in terms of investment cost. Olefins saturation and octane loss will be limited but not eliminated altogether so that some form of octane compensation mechanism will be required at the cost of some energy consumption.

There would be a small reduction of the average olefins content of gasolines, estimated at 2-3% by our model. This number reflects the current state of the technology. Technologies may further progress in the coming years to such an extent that the removal of sulphur may become possible with very little olefins saturation so that this number should become smaller. It must in any case be stressed that this would be an average figure. Some individual refineries would still have enough flexibility to reformulate their blends without significant olefin reduction. This should therefore not be construed as grounds for reducing the olefin specification, which would only further limit the flexibility and therefore increase the costs of some refineries. It must also be noted that any mandated reduction in olefins content creates additional strain on the already constraining aromatics specification, as these two groups of compounds are the main sources of octane.

Other gasoline properties would be largely unaffected although the octane compensation mechanisms, typically involving a combination of reformate and MTBE, would further stretch the ability of refineries to meet aromatics and volatility specifications. MON would still be universally constraining while RON would become limiting in an increasing number of refineries.

6.2. DIESEL

In order to meet the 10 ppm diesel specification, virtually every EU refinery would need to invest in additional hydrodesulphurisation capacity or at least in a major revamp of existing plants. The scope for this is likely to be limited, as most facilities will already be stretched to meet the current or 2005 limit. As explained in section 5.3 we expect refiners to build-in some spare capacity to cover for more frequent plant upsets and reprocessing associated to the very high levels of desulphurisation and to the lack of sulphur sinks.

Generally these additional plants would not consume much more energy than existing ones while the extra hydrogen consumption would be small. For that reason additional CO_2 emissions would be relatively limited. Investments would be high.

Bulk diesel properties such as density, cetane and total aromatics would not be much affected. A small overall reduction of polyaromatics is to be expected although individual levels would still be very much influenced by other factors such as the origin of the crude oil used.

Performance properties such as lubricity, conductivity and oxidation stability would definitely suffer, as deep desulphurisation would remove most of the polar compounds that contribute to such performance. This would have to be compensated by extra additivation at a cost that we have estimated at 1 USD/t of finished diesel equivalent to some 150 MUSD/a for the EU Industry. It must in addition be noted that the very low conductivity of ULS fuels would call for handling precautions not generally associated with today’s road fuels. Even with additivation all handling procedures would need to be reviewed to ensure that the appropriate safety rules are respected in terms of velocities during transfers and allowance for residence times in storage tanks to dissipate electrostatic charges built up after completion of a transfer.

6.3. OVERALL COSTS AND CARBON DIOXIDE EMISSIONS

Table 4 presents the estimated cost and carbon dioxide emissions data for changing the sulphur specification of each fuel from 50 to 30 and 10 ppm as well as for both fuels simultaneously. The figures, previously found in the context of Auto-Oil I to reduce sulphur from the current level to 50 ppm, are also included for comparison (the figures presented here are for sulphur reduction only, i.e. exclude the effect of gasoline aromatics reduction).

Table 4 Refinery costs and CO_2 emissions

Present value of costs (GEUR)

Sulphur	From	Current(*)	50	50
specification (ppm)	To	50	30	10
Gasoline		3.9	1.8	5.8
Diesel		8.9	2.6	7.5
Total (separate)		*12.8*	*4.4*	*13.3*
Gasoline <u>and</u> diesel		12.3		13.5

CO2 emissions

		Current(*) 50	30 ppm S	10 ppm S
Mt/a				
Gasoline		3.3	1.5	4.3
Diesel		3.0	0.8	1.8
Total (separate)		*6.3*	*2.3*	*6.1*
Gasoline <u>and</u> diesel		6.4		6.5
% of total CO2 emissions from road fuels				
Gasoline		0.35	0.16	0.46
Diesel		0.32	0.08	0.19
Total (separate)		*0.67*	*0.25*	*0.65*
Gasoline <u>and</u> diesel		0.68		0.69

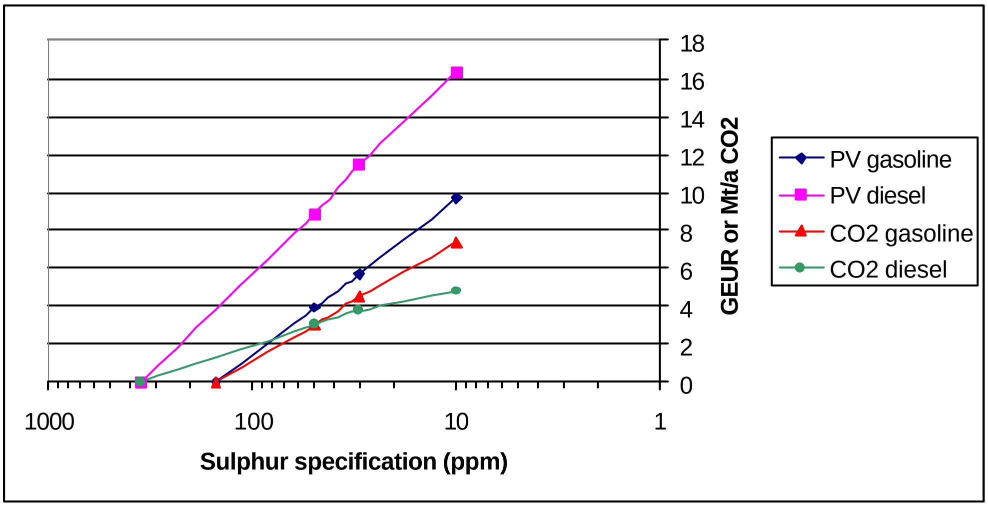
(*) 150 ppm for gasoline and 350 ppm for diesel

Notes:

1. CO_2 emissions from EU refineries are in the order of 100 Mt/a. A move from 50 to 10 ppm sulphur for road fuels would correspond to an increase of some 6.5%.
2. The figures relative to the reduction from current levels to 50 ppm were derived from a slightly different base case. As a result they are somewhat underestimated.

Figure 1 shows the cumulative costs from the current specification down to the 10 ppm limit. The costs as well as the CO_2 emissions increase exponentially as the sulphur specification decreases, the law of diminishing returns applying.

Figure 1 Cumulative refinery costs and CO_2 emissions



The type of plants required to achieve ULS gasoline and diesel are fundamentally different and we see no logical reason for significant synergies between the two fuels. This is indeed supported by our model, which suggests essentially additive costs and CO_2 emissions. In fact at 10 ppm, our model suggests a modest antagonism between the two measures. When both fuels are dealt with simultaneously, both the costs and the CO_2 emissions are somewhat greater than those for each individual fuel added together.

Details of the new investments and costs per region are given in **Appendix 6**.

It must be noted that such major investments in similar plants in the majority of refineries would require a suitable lead-time to allow orderly design engineering, procurement and construction. Under normal circumstances a typical refinery investment project takes two to three years from conception to start-up and high demand for similar plants could stretch resources for all related activities. This is particularly so as the US refining industry may be faced with a similar target more or less simultaneously and some of the rest of the world may follow suit.

This study assumes the issue to be fully resolved internally within the EU through a co-ordinated investment approach. If virtually all refiners would need to somehow adapt their operation, each company would, in reality, have their own views and make their own decisions. The sum of individual assumptions is unlikely to reflect reality and this could result in unbalanced supply/demand for instance through over-reliance on imports or on low-sulphur crudes. In this way a mandated universal introduction could result in supply disturbances.

7. REFERENCES

1. CONCAWE (1999) EU oil refining industry costs of changing gasoline and diesel fuel characteristics. Report No. 99/56. Brussels: CONCAWE

APPENDICES

1. 1998 EU-15 petroleum products demand
2. EU-15 and regional call on refineries (2010 base case)
3. FCC gasoline and chemical returns processing scheme
4. Gasoils processing scheme
5. Calculation of costs for security of supply for diesel
6. Incremental investments, operating costs and CO_2 emissions per region

APPENDIX 1

1998 EU-15 PETROLEUM PRODUCTS DEMAND

Region	**SCA**	**UKI**	**BEN**	**GEA**	**FRA**	**SPP**	**ITG**	**EU-15**
Gasoline	7.9	23.2	7.2	32.7	14.6	11.0	22.9	**119.5**
Jet/kerosene	2.2	13.4	5.3	6.9	5.4	4.3	5.4	**42.9**
Diesel	6.8	18.4	10.9	31.1	27.9	18.0	19.8	**132.9**
Gas oil	8.0	9.0	10.2	37.3	16.7	8.7	13.7	**103.6**
Fuel oil	8.0	8.2	17.1	9.3	6.9	15.8	33.8	**99.1**
Other	7.3	12.4	14.4	32.5	19.8	18.8	19.3	**124.5**
Total	**40.2**	**84.6**	**65.1**	**149.8**	**91.3**	**76.6**	**114.9**	**622.5**

Note: The figures include international bunkers but exclude refinery fuel and loss.

APPENDIX 2

EU-15 AND REGIONAL CALL ON REFINERIES (Mt/a) 2010 BASE CASE

Region	**SCA**	**UKI**	**BEN**	**GEA**	**FRA**	**SPP**	**ITG**	**EU-15**
Crude								
Brent	4.5	48.3	0.9	28.8	28.3	26.6	35.1	172.5
Iranian	6.2	15.6	6.0	13.0	18.0	26.6	36.0	121.4
Kuwait	8.8	22.0	50.1	40.2	28.9	20.7	45.4	216.1
Nigerian	17.1	11.2	22.1	25.7	13.9	9.5	1.3	100.8
Algerian	1.9	1.8	0.5	5.1			1.0	10.3
Total	38.5	98.9	79.6	112.8	89.1	83.4	118.8	621.1
Other feedstocks								
MTBE	0.2	0.4	0.0	0.2	1.3	0.3	0.2	2.6
BTX return	0.2	0.1	0.5	0.2	0.4	0.3	0.7	2.4
Gas oil component	1.3			10.4	3.3			15.0
Methanol		0.2	0.1	0.0	0.2	0.1	0.3	0.9
Natural gas			2.0	0.5				2.5
Chemical Returns	0.2	0.5	0.3	3.6	1.3	1.1	1.0	8.0
FCC/HC feed		3.5		0.8				4.3
Total	1.9	4.7	2.9	15.7	6.5	1.8	2.2	35.7
Products								
Gas/LPG	0.4	1.4	2.1	4.8	3.0	3.4	4.6	19.7
Naphtha	0.7	2.2	4.9	8.1	5.2	4.3	9.9	35.3
Gasoline 93 exp.	0.0	1.0	5.0	0.0	1.0	1.0	0.0	8.0
Gasoline 98	0.0	1.2	0.0	1.4	4.8	2.1	0.0	9.5
Gasoline 95	9.2	28.7	10.6	21.8	14.4	12.8	21.7	119.2
Gasoline 92	0.0	0.0	0.0	4.1	0.0	0.0	0.0	4.1
Jet/kerosene	2.0	14.5	7.3	8.6	5.9	5.9	5.7	49.9
Diesel	8.7	21.1	16.3	25.9	22.3	24.0	36.8	155.1
Other gasoils	8.1	5.0	11.0	28.9	13.5	5.0	8.2	79.7
Fuel oil	5.5	9.6	2.3	5.7	9.3	8.9	14.2	55.5
Bunker fuel	0.5	2.8	14.5	1.7	2.1	3.6	4.0	29.2
Other	1.6	5.6	1.5	5.3	5.0	7.1	4.3	30.4
Sulphur	0.2	0.7	0.8	1.0	0.7	0.4	1.0	4.8
Total	36.9	93.8	76.3	117.3	87.2	78.5	110.4	600.4
Ref. Fuel & Loss	3.5	10.0	6.4	10.9	8.1	6.9	10.6	56.4

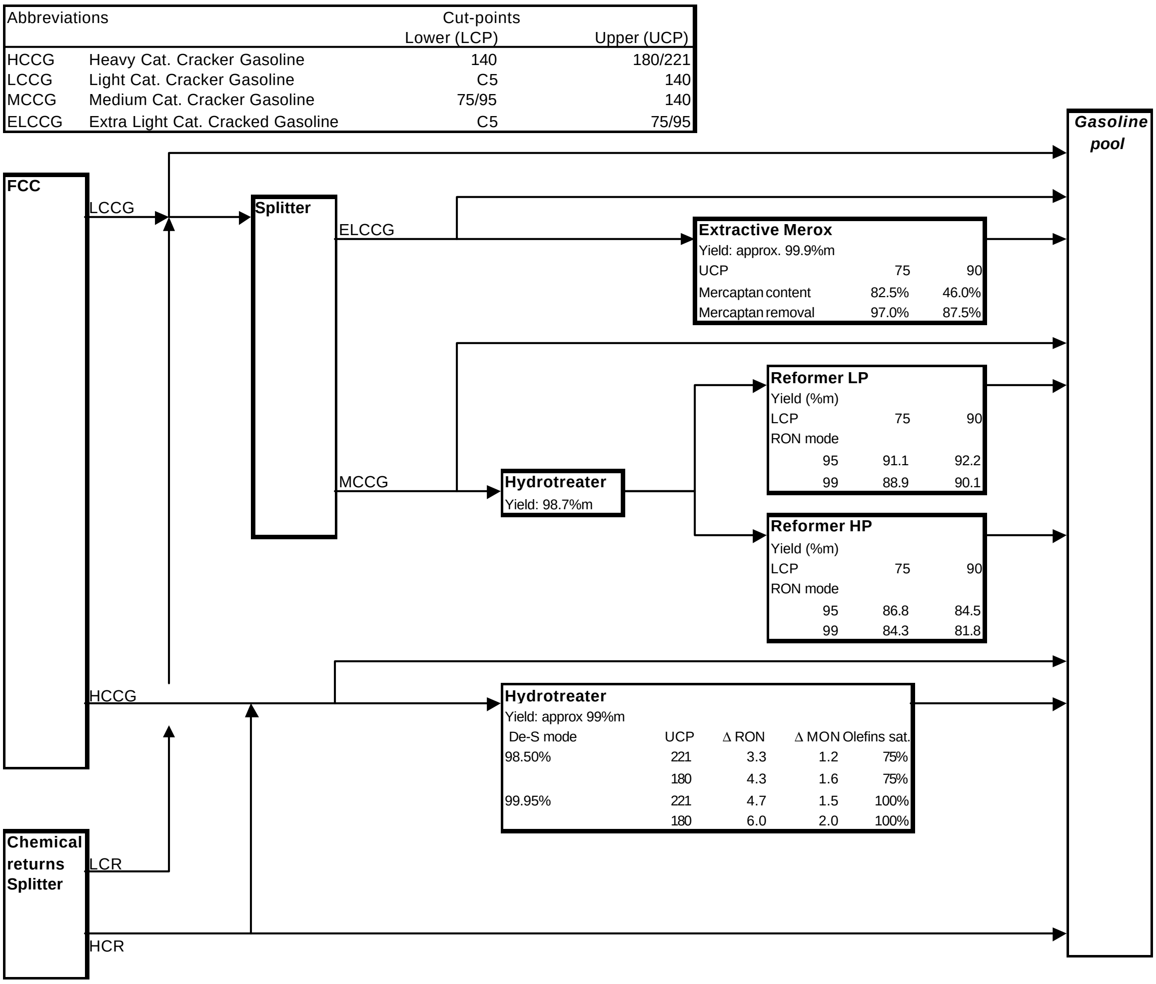
Note: Some 25 Mt/a of naphtha, 10 Mt/a of Gas/LPG and 5 Mt/a of petroleum coke not considered as call on refineries, e.g. supplied directly as crude condensate or direct imports.

APPENDIX 2 *cont'd*

Region	**SCA**	**UKI**	**BEN**	**GEA**	**FRA**	**SPP**	**ITG**	**EU-15**
Import/Export balance								
Gas/LPG	-0.2					0.2		0.0
Naphtha		-0.1	-0.5	6.7	0.1		-6.2	0.0
Gasoline 93 exp.		-1.0	-5.0		-1.0	-1.0		-8.0
Gasoline 98		-1.2		1.2				0.0
Gasoline 95	0.8	1.2	-1.4				-0.6	0.0
Jet/kero	0.7	1.3	-2.0					0.0
AGO	-1.7	-1.5	-6.0	4.9	11.1		-6.8	0.0
Gas oil			-0.3	2.1	2.4		-4.2	0.0
Fuel oil	0.7	-0.7	-0.7		-3.9	-0.1	4.0	-0.7
Bunker fuel		-1.1					1.1	0.0
Other	0.2	2.6	-0.2	1.2	-0.5	-3.6	0.3	0.0
TOTAL	0.5	-0.5	-16.1	16.1	8.2	-4.5	-12.4	-8.7

APPENDIX 3

FCC GASOLINE AND CHEMICAL RETURNS PROCESSING SCHEME

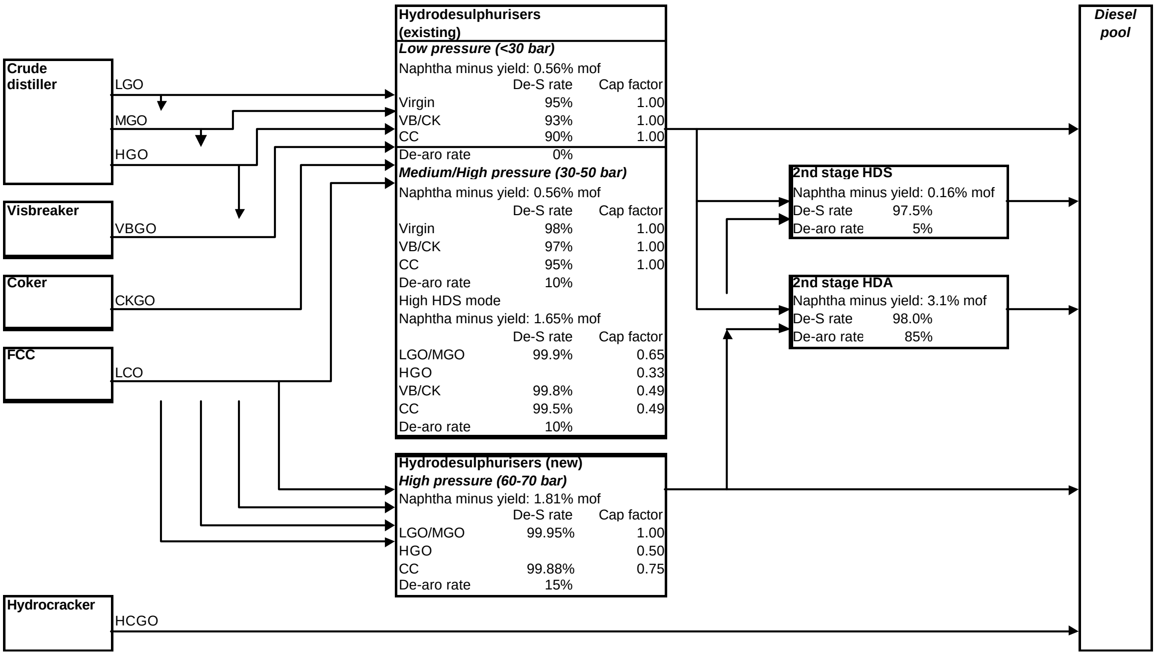


Abbreviations		Cut-points Lower (LCP)	Upper (UCP)
HCCG	Heavy Cat. Cracker Gasoline	140	180/221
LCCG	Light Cat. Cracker Gasoline	C5	140
MCCG	Medium Cat. Cracker Gasoline	75/95	140
ELCCG	Extra Light Cat. Cracked Gasoline	C5	75/95

APPENDIX 4

GASOILS PROCESSING SCHEME

Abbreviations		Cut-points Lower (LCP)	Upper (UCP)
LGO	Virgin Light Gasoil	235-250	300
MGO	Virgin Medium Gasoil	300	350
HGO	Virgin Heavy Gasoil	350	370
VBGO	Visbreaker Gasoil	155	350
LCO	Light Cycle Oil (FCC gasoil)	180-221	350
HCGO	Hydrocracked gasoil	250	350



Note: Virgin gasoils can also be blended as such into the pool. This option is, however, irrelevant for all post 2005 scenarios

APPENDIX 5

CALCULATION OF COSTS FOR SECURITY OF SUPPLY OF DIESEL

Additional capacity

An extra hydrodesulphurisation capacity of 7.5% of the total diesel production (including exports) is expected to be built to cover for technical upsets and enable reprocessing of off-spec products. The cost of this extra capacity is calculated as the marginal cost to build a slightly larger plant (1.5 Mt/a) assuming a capex of 75 MUSD for a full 1.3 Mt/a plant.

Capex per ton on additional capacity =

$$\text{Capex for 1.3 Mt/a plant} \times ((1.5 / 1.3)^{0.65} - 1) / (1.5 - 1.3)$$

Cost of extra capacity (MUSD) =

Tons of additional capacity x capex per ton

$$(0.075 \times \text{Diesel production}) \times (75 \times ((1.5/1.3)^{0.65} - 1) / (1.5 - 1.3))$$

Extra stock holding

During a plant upset, the daily production of untreated gasoil has to be held in stock for later reprocessing. An additional 16 days off stream per annum is assumed. This material is reprocessed using the spare capacity available. Accounting for some seasonality in the demand we have assumed 20% spare capacity to be available for reprocessing. This corresponds to a period of
16 / 0.2 = 80 days

The cost of carrying this stock is calculated based on the full amount for half the time assuming a product value of 234 USD/t and 7% interest rate:

Cost of extra inventory (MUSD/a) =

(t reprocessed) x (1/2 days for reprocessing) x (USD/t inventory holding cost)

Cost of extra inventory (MUSD/a) =

$$(\text{Diesel prod.} \times 16 / 365) \times (16 + 16 / 0.2 / 2 / 365) \times (234 \times 0.07)$$

APPENDIX 6

INCREMENTAL INVESTMENTS, OPERATING COSTS AND CO$_2$ EMISSIONS PER REGION

GASOLINE 30 ppm

Region	SCA	UKI	BEN	GEA	FRA	SPP	ITG	EU-15
Investment costs (MUSD)								
New plants								
Kero/Naphtha hydrotreater	13	4	10	34	9	6	10	86
FCC gasoline splitter	2	3	4	12			13	34
Chemical return splitter	0		3	9	4	4	4	25
FCC gasoline hydrotreatment	10	39	10	40	25	20	10	154
FCC gasoline extractive Merox	0	0		15		2		18
LP reformer		17						17
HP reformer								
Reformer upgrade						20		20
Reformate splitter		1	1	2		2	0	6
Isomerisation (once-through)			1					1
Isomerisation (recycle)						21	43	64
Isomerisation (LPL)		9	12	18			24	62
Alkylation				60				60
MTBE						2		2
TAME								
Butamer								
Gasoil Hydrodesulphuriser HP				-1		-1		-2
2nd stage gasoil HDS				-1		-3	6	1
2nd stage gasoil hydrogenation	-1		2					1
LCO dearomatisation								
Vacuum distillation					0			0
FCC				14		1		16
Hydrocracker (recycle)		2						2
Hydrocracker (once-through)								
FCC feed hydrotreater	2		15			41	27	84
Hydrogen manufacturing				8	-3	8	5	18
Sulphur recovery				4		4		8
Flue gas desulphurisation					-6			-6
Other Investments								
Security of supply								
Hydrogen recovery				-5	10	-5		
Offsite facilites for transfers					15			15
External MTBE Plants	1				1	1		2
External Methanol Plants	0	1			35	2	-3	36
Total Incremental Investment								
Internal	27	74	57	209	56	122	141	685
Others	1	1			36	3	-3	38
Total	28	75	57	209	92	125	138	724
Incremental Operating costs								
Maintenance, ops & OH	1.2	3.2	2.5	9.0	2.4	5.3	6.1	29.6
Transfer costs	-0.3	0.4	-8.5	0.2	0.4	0.3	-2.2	-9.7
Energy cost (global)	3.0	6.2	10.4	23.9	10.1	11.1	10.6	75.3
Supply security inventory financing								
Cetane additive								
Lubricity additivation								
External maintenance, ops & OH	0.0	0.0			1.6	0.1	-0.1	1.6
Total	3.9	9.8	4.4	33.1	14.5	16.8	14.4	96.9
Present Value of costs								
MUSD	66	171	99	532	233	289	278	1668
MEUR	69	180	105	560	246	304	292	1756
Incremental CO2 emissions (Mt/a)	0.06	0.13	0.22	0.50	0.17	0.23	0.23	1.54

APPENDIX 6 *cont'd*

GASOLINE 10 ppm

Region	**SCA**	**UKI**	**BEN**	**GEA**	**FRA**	**SPP**	**ITG**	**EU-15**
Investment costs (MUSD)								
New plants								
Kero/Naphtha hydrotreater	34	9	37	66	33	26	44	250
FCC gasoline splitter	10	15	13	37	5	1	25	105
Chemical return splitter	2	6	3	10	7	6	11	47
FCC gasoline hydrotreatment	9	83	50	105	73	31	76	426
FCC gasoline extractive Merox	7	37	16	52	27	21	33	192
LP reformer		102						102
HP reformer	3	7		5				16
Reformer upgrade		20	40			20	160	240
Reformate splitter	1	6	7	4	0	5	0	22
Isomerisation (once-through)			14					14
Isomerisation (recycle)			13	85		72	99	268
Isomerisation (LPL)	21	50	47	65		21	56	260
Alkylation	3		27	137		16	85	269
MTBE	4		4				2	10
TAME			2			75	12	89
Butamer								
Gasoil Hydrodesulphuriser HP				18		2		20
2nd stage gasoil HDS						-3	-29	-33
2nd stage hydrogenation	-1		1					
LCO dearomatisation								
Vacuum distillation	3		2		-1			4
FCC			40	79		4		123
Hydrocracker (recycle)		16						16
Hydrocracker (once-through)								
FCC feed hydrotreater	8				7	39		54
Hydrogen manufacturing			3			18	10	30
Sulphur recovery						4	4	8
Flue gas desulphurisation				11	-6			6
Other Investments								
Security of supply								
Hydrogen recovery		10	-10	-5	5	-5	-5	-10
Offsite facilites for transfers				10	-35			-25
External MTBE Plants	1				1			1
External Methanol Plants	4	3	-1		45	26	7	83
Total Incremental Investment								
Internal	104	361	308	681	115	351	583	2503
Others	5	3	-1		45	26	7	85
Total	109	364	308	681	160	377	589	2588
Incremental Operating costs MUSD/a								
Maintenance, ops & OH	4.5	15.6	13.3	29.4	5.0	15.2	25.2	108.1
Transfer costs	0.8	1.4	-5.3	4.7	0.2	0.2	-29.4	-27.4
Energy cost (global)	18.2	26.0	11.2	52.8	18.7	39.5	44.6	211.1
Supply security inventory financing								
Cetane additive								
Lubricity additivation		0.4						0.4
External maintenance, ops & OH	0.2	0.1	0.0		2.0	1.1	0.3	3.7
Total	23.7	43.5	19.3	86.9	25.8	56.0	40.7	296.0
Present Value of costs								
MUSD	340	788	496	1528	412	923	986	5474
MEUR	358	830	522	1608	433	972	1038	5762
Incremental CO2 emissions (Mt/a)	0.38	0.54	0.24	1.11	0.34	0.80	0.93	4.34

APPENDIX 6 *cont'd*

DIESEL 30 ppm

Region	SCA	UKI	BEN	GEA	FRA	SPP	ITG	EU-15
Investment costs (MUSD)								
New plants								
Kero/Naphtha hydrotreater	11	1	15	48	75	9	18	179
FCC gasoline splitter				0				0
Chemical return splitter				0	-2	0	0	-2
FCC gasoline hydrotreatment		1			1	1		3
FCC gasoline extractive Merox		-1						-1
LP reformer								
HP reformer								
Reformer upgrade						20		20
Reformate splitter		0		0	3	1	0	3
Isomerisation (once-through)								
Isomerisation (recycle)								
Isomerisation (LPL)		3					3	6
Alkylation								
MTBE								
TAME								
Butamer								
Gasoil Hydrodesulphuriser HP		73	15	61	87	101	63	399
2nd stage gasoil HDS				-1		-3	9	5
2nd stage hydrogenation	3		9	5	27		50	94
LCO dearomatisation								
Vacuum distillation					0	1		1
FCC								
Hydrocracker (recycle)		16						16
Hydrocracker (once-through)								
FCC feed hydrotreater					2	-2		1
Hydrogen manufacturing		5		8	23	5	15	55
Sulphur recovery								
Flue gas desulphurisation					-6			-6
Other Investments								
Security of supply	8	19	15	24	20	22	34	
Hydrogen recovery		-5		5	-5	-5	-15	-25
Offsite facilites for transfers					15			15
External MTBE Plants	1				1	1		3
External Methanol Plants	0				42	0		43
Total Incremental Investment								
Internal	22	113	54	150	240	150	176	905
Others	1				44	1		46
Total	23	113	54	150	283	151	176	950
Incremental Operating costs								
Maintenance, ops & OH	0.6	4.0	1.7	5.4	9.5	5.5	6.2	33.0
Transfer costs	0.0	-0.7	4.3	-1.5	0.6	1.6	5.2	9.6
Energy cost (global)	1.7	1.5	2.7	6.9	12.2	5.6	8.6	39.1
Supply security inventory financing	0.3	0.7	0.5	0.8	0.7	0.8	1.2	4.9
Cetane additive								
Lubricity additivation	3.0	9.6	7.4	11.8	10.2	10.6	16.7	69.3
External maintenance, ops & OH	0.0				1.9	0.0		2.0
Total	5.7	15.1	16.6	23.5	35.0	24.1	37.8	157.7
Present Value of costs								
MUSD	79	260	216	379	625	386	544	2488
MEUR	83	273	227	398	658	406	573	2619
Incremental CO2 emissions (Mt/a)	0.03	0.03	0.06	0.15	0.21	0.12	0.18	0.77

APPENDIX 6 *cont'd*

DIESEL 10 ppm

Region	SCA	UKI	BEN	GEA	FRA	SPP	ITG	EU-15
Investment costs (MUSD)								
New plants								
Kero/Naphtha hydrotreater	5	3	15	80	22	11	5	141
FCC gasoline splitter							1	1
Chemical return splitter					-2		1	-1
FCC gasoline hydrotreatment		-1			-11		-1	-13
FCC gasoline extractive Merox		-1			0			-1
LP reformer		2						2
HP reformer								
Reformer upgrade						40	160	200
Reformate splitter		0	0	0	2	1	3	7
Isomerisation (once-through)							4	4
Isomerisation (recycle)							2	2
Isomerisation (LPL)		3					3	6
Alkylation								
MTBE								
TAME								
Butamer								
Gasoil Hydrodesulphuriser HP	23	367	46	302	462	490	399	2088
2nd stage gasoil HDS						-3	12	8
2nd stage hydrogenation	19		68	40	19	21	173	339
LCO dearomatisation								
Vacuum distillation						7		7
Visbreaker							6	6
FCC								
Hydrocracker (recycle)			5					5
Hydrocracker (once-through)								
FCC feed hydrotreater	2		20		2		5	29
Hydrogen manufacturing	5	13	8	20	40	30	50	165
Sulphur recovery			4				4	8
Flue gas desulphurisation					-6	11		6
Other Investments								
Security of supply	24	58	45	71	61	66	101	
Hydrogen recovery		-5	-5	-5			-15	-30
Offsite facilites for transfers					2			2
External MTBE Plants	1				1	1		2
External Methanol Plants	0	0			44	0		44
Total Incremental Investment								
Internal	78	438	204	508	592	673	911	3404
Others	1	0			45	1		46
Total	79	438	204	508	636	674	911	3450
Incremental Operating costs								
Maintenance, ops & OH	2.3	16.4	6.9	18.9	22.9	26.2	35.0	128.7
Transfer costs	0.0	-0.9	-4.0	-2.5	5.1	-0.3	-6.0	-8.5
Energy cost (global)	3.3	8.7	-1.3	15.3	12.5	20.0	28.1	86.6
Supply security inventory financing	0.8	2.0	1.5	2.4	2.1	2.3	3.5	14.6
Cetane additive								
Lubricity additivation	6.7	21.1	16.3	25.9	22.3	24.0	36.8	153.1
External maintenance, ops & OH	0.0	0.0			1.9	0.0		1.9
Total	13.1	47.3	19.5	60.1	66.9	72.2	97.4	376.5
Present Value of costs								
MUSD	207	899	394	1094	1289	1378	1860	7121
MEUR	218	947	415	1151	1356	1450	1958	7496
Incremental CO2 emissions (Mt/a)	0.07	0.18	-0.02	0.32	0.21	0.42	0.59	1.77

APPENDIX 6 *cont'd*

GASOLINE AND DIESEL 10 ppm

Region	SCA	UKI	BEN	GEA	FRA	SPP	ITG	EU-15
Investment costs (MUSD)								
New plants								
Kero/Naphtha hydrotreater	40	10	32	120	26	25	51	303
FCC gasoline splitter	9	14	13	37	5	0	24	104
Chemical return splitter	2	6	3	10	8	7	11	47
FCC gasoline hydrotreatment	3	85	49	106	73	31	72	420
FCC gasoline extractive Merox	8	37	16	53	26	20	34	193
LP reformer		98						98
HP reformer	11	6		5				22
Reformer upgrade			40			80	160	280
Reformate splitter	1	6	7	5	1	5	2	28
Isomerisation (once-through)						2		2
Isomerisation (recycle)			26	82		86	177	371
Isomerisation (LPL)	24	53	53	74		30	71	305
Alkylation			22	140			3	165
MTBE	2						2	4
TAME			2			60	17	78
Butamer								
Gasoil Hydrodesulphuriser HP	22	375	42	357	502	494	408	2200
2nd stage gasoil HDS				-1		-3	24	20
2nd stage hydrogenation	-1		68	28	41	12	128	276
LCO dearomatisation								
Vacuum distillation	1		10		0	0		11
Visbreaker								
FCC			32	70				102
Hydrocracker (recycle)						6		6
Hydrocracker (once-through)						5		5
FCC feed hydrotreater	10		8		2	47		67
Hydrogen manufacturing	8	10	5	20	23	50	70	185
Sulphur recovery				4	4	4		12
Flue gas desulphurisation				22	11			34
Other Investments								
Security of supply	24	58	45	71	61	66	101	
Hydrogen recovery	5	15	-20	-5	-5	-15	-15	-40
Offsite facilites for transfers	6			10	17			33
External MTBE Plants	1				1	1		2
External Methanol Plants	3	3	-1		45	21	8	79
Total Incremental Investment								
Internal	174	774	452	1208	794	1011	1340	5753
Others	4	3	-1		46	22	8	81
Total	178	777	451	1208	840	1033	1348	5835
Incremental Operating costs								
Maintenance, ops & OH	6.5	30.9	17.6	49.1	31.7	40.8	53.5	230.2
Transfer costs	1.6	1.1	0.8	3.0	7.5	1.8	-15.2	0.6
Energy cost (global)	22.5	35.3	22.1	67.7	29.2	57.0	77.9	311.7
Supply security inventory financing	0.8	2.0	1.5	2.4	2.1	2.3	3.5	14.6
Cetane additive								
Lubricity additivation	6.7	21.1	16.3	25.9	22.3	24.0	36.8	153.1
External maintenance, ops & OH	0.2	0.1	-0.1		2.0	0.9	0.4	3.5
Total	38.3	90.5	58.2	148.1	94.8	126.8	156.9	713.7
Present Value of costs								
MUSD	551	1660	1019	2652	1765	2269	2878	12793
MEUR	580	1747	1072	2792	1857	2388	3029	13466
Incremental CO2 emissions (Mt/a)	0.47	0.74	0.47	1.42	0.56	1.17	1.63	6.46