EU oil refining industry costs of changing gasoline and diesel fuel characteristics

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ABSTRACT

This report presents the results of a study to assess the EU-15 refining industry implications of changing gasoline and diesel fuel characteristics, for year 2005 onwards. The study's starting point is the EU Council Common Position on the AO1 proposed year 2000 road fuels, i.e. gasoline aromatics 42%, sulphur 150 ppm, olefins 18% and diesel cetane number (CN) 51, sulphur 350 ppm.

The costs to oil refiners and the CO_2 emissions effects have been calculated with regards to the changes to gasoline and diesel fuel characteristics given in the Fuels Directive (98/70/EC) agreed in Conciliation. These are for gasoline: sulphur content from 150 ppm to 50 ppm and aromatics content from 42% to 35%; for diesel: sulphur content from 350 ppm to 50 ppm. In addition an increase in CN from 51 to 55 and further towards 58, if achievable, is reported on.

The complex interactive analysis was carried out using a purpose built supply/demand refinery LP model featuring four refinery types and seven regions. This degree of definition is essential to reduce the over optimisation of such models which otherwise seriously underestimate effects. On the other hand, some component transfers between refinery types are allowed. This approach results in some equalisation of qualities (especially aromatics and olefins contents of gasoline) and provides some low cost networking solutions. The results are published in this report and in the associated detailed tabulations available as computer files to assist in the analysis of fuel related vehicle emissions measures.

The single parameter cost for reformulation depends on the sequence applied as a result of synergy or antagonism between the required processing needs.

The CO_2 emissions effects are in the unwanted direction, reflecting additional fuel and hydrogen in processing.

KEYWORDS

Automotive fuel, CO_2 emissions, cost, diesel fuel, energy consumption, EU-15, fuel specification, gasoline, LP model, MTBE, oil industry, refinery, reformulation.

NOTE 1
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NOTE 2
This study started before the Conciliation agreement on the 2000/2005 fuel quality requirements. Hence, the EU Council Common Position of October 1997 has been taken as the baseline for calculating costs.

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SUMMARY

With the report no. 95/54 "Interim report on the European refining implications of severe reformulation of gasoline and diesel fuel", CONCAWE contributed to Auto-Oil-1, a programme that developed proposals for year 2000 (optimal for the EU) to reduce emissions from road transport. Since then, CONCAWE has refined the methodology it uses to develop refinery costs, energy consumption and CO_2 emission effects of changing the properties of gasoline and diesel fuel. CONCAWE has developed the expertise in this highly technical and complex field to provide sound advice, not only to its own members in the oil refining industry but to anyone prepared to study and to debate such matters.

The CONCAWE methodology uses a purpose made crude oil supply/petroleum product demand refinery and distribution linear program (LP) model linked to a cost and CO_2 emission effects analysis tool. Seven regions are followed covering the whole EU oil product demand amounting to some 600 Mt/a: Scandinavia (excluding Norway), Benelux, UK/Ireland, Germany/Austria, France, Iberia and Italy/Greece. Four refinery configuration types are used to represent the 90 EU road fuels refineries with a total capacity of nearly 650 Mt/a: Simple, Cat Cracking, Hydrocracking and Cat Cracking & Hydrocracking. All of these features are analysed interactively. The costs calculated are economic optima, as the chosen methodology allows for blending component movement between refinery types with associated handling costs. This approach allows low capital cost smoothing for meeting extreme values of gasoline aromatics and olefins and diesel cetane between refinery types. It also reduces the inherent tendency of such models to over optimise and avoids the understatement of costs that invariably occurs in studies done too superficially.

All reported costs are **on top of** the EU Council Common Position (October 1997, OJ C351) on proposed road fuels specifications for 2000 that already requires substantial expenditure. The costs of changing gasoline and diesel quality and composition constraints arise from the investment costs for expanded and new refinery process units, increased refinery fuel consumption and other operating/maintenance costs, and inter refinery transport costs. External supplies of MTBE and methanol have similar cost elements. Overall costs are calculated in terms of Net Present Value (NPV) over the 15 years life expectancy of refinery projects with future money discounted at 7% per annum.

For **gasoline**, (127 Mt/a in 2010) the costs of reducing sulphur content from 150 ppm (mg/kg) to 50 ppm have been considered, along with aromatics content reduced from 42% (vol.) max specification down to 35%. Ignoring synergies and antagonisms where they are not very major factors, the costs suitably rounded in billions of European Currency Units (1 GEUR = 1.1 G$ US) are:

Sulphur	150 ppm	100 ppm	50 ppm
NPV GEUR	Base	1	3.5

Aromatics	42% vol.	35% vol.
NPV[1] GEUR	Base	3* to 4.5

* Based on sulphur controls come first. Aromatics first incurs the cost synergy otherwise borne in conjunction with the sulphur measure. The combined effect of 50 ppm and 35% aromatics is 6.5 GEUR. The cost at 35% aromatics reflects the change from 37.8% average (base case result from 42% spec.).

[1] NPV is Net Present Value; GEUR (Giga EUR) equals 1,000 million EUR

Production of low aromatics gasoline is particularly problematic. Some simple and hydrocracking refineries anticipate commercial/geographic difficulties obtaining the imported components needed for their survival. Furthermore, the EU would become more reliant on imported MTBE.

For **diesel** (155 Mt/a in 2010) the costs of reducing sulphur amount to:

Sulphur	350 ppm	200 ppm	100 ppm	75 ppm	50 ppm
NPV GEUR	Base	2.5	5	6	8

The costs of increasing cetane number (CN) once sulphur is reduced to 50 ppm are:

Cetane Number (CN)	51	55	Max possible: 55 to 58
NPV GEUR	Base	9	>35

Total package costs for gasoline and diesel fuel are shown in **Figures A** and **B**.

The developments in desulphurisation process performance over the last few years, made sulphur reduction achievable by medium to high-pressure hydro-desulphurisation at lower costs than before. Current gasoil desulphurisation technology allows this decoupling of sulphur and cetane control.

A diesel fuel specification of 58 CN is now found to be not viable for the whole of Europe pending further development of proven refining process technology. The higher CN case calculations in the study includes maximum use of CN improver additive providing 3 CN points on average.[2] Even with CN improver, the maximum CN found for EU as a whole is about 56. Above this limit, the results include regions infeasible to produce CN>56 and refinery processes considered to be extreme from a practicality standpoint. This finding requires further study. In general, more research into refinery CN control and measurement methods is required. Severe problems are also encountered in developing processes that simultaneously improve cold flow properties and increase CN to a level of 58 while maintaining diesel yields.

Process interactions between gasoline and severely modified diesel fuels also become more critical making short-notice supply difficulties likely for both fuels resulting in price fluctuations.

CO_2 emissions may decrease slightly if MTBE (natural gas/LPG source instead of crude oil) is used to control gasoline aromatics. Sulphur control for diesel requires from 25 tonnes of CO_2 emission (for 150 ppm sulphur) up to 37 tonnes (for 50 ppm sulphur), for every tonne of SO_2 emission reduced, compared to the starting level of 350 ppm. On an incremental basis the CO_2/SO_2 ratio increases to about 90 at the level of 50 ppm sulphur. At the low sulphur levels in gasoline the ratio of CO_2 increase to SO_2 decrease is even higher. CN control becomes energy intensive at high CN levels because of the CO_2 produced making all the additional hydrogen required by the necessary hydro-dearomatising and hydrocracking process units. The cetane related CO_2 emissions amount to 8 Mt/a when cetane is increased from the base case of CN 51 to 55 and increase to 12 Mt/a when CN changes from 55 to 56. These CO_2 emissions come on top of the 3 Mt/a required to reduce diesel sulphur content from 350 to 50 ppm mass. The combined effect of reducing the specifications of gasoline sulphur from 150 to 50 ppm and aromatics from 42% to 35%, is estimated to increase CO_2 emissions by 2.5 Mt/a.

2 A lower cost option would make use of more than 3 points average cetane boost from additives and is estimated to be able to achieve 55 CN without major additional processing.

Figure A Gasoline sulphur and aromatics constraint costs

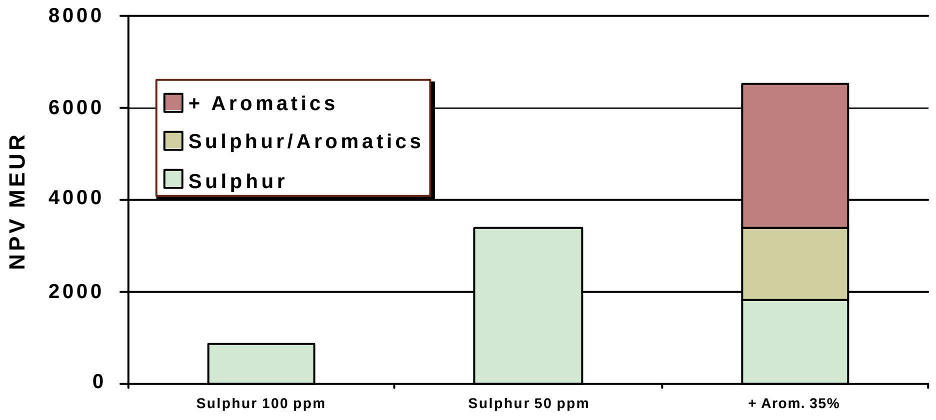
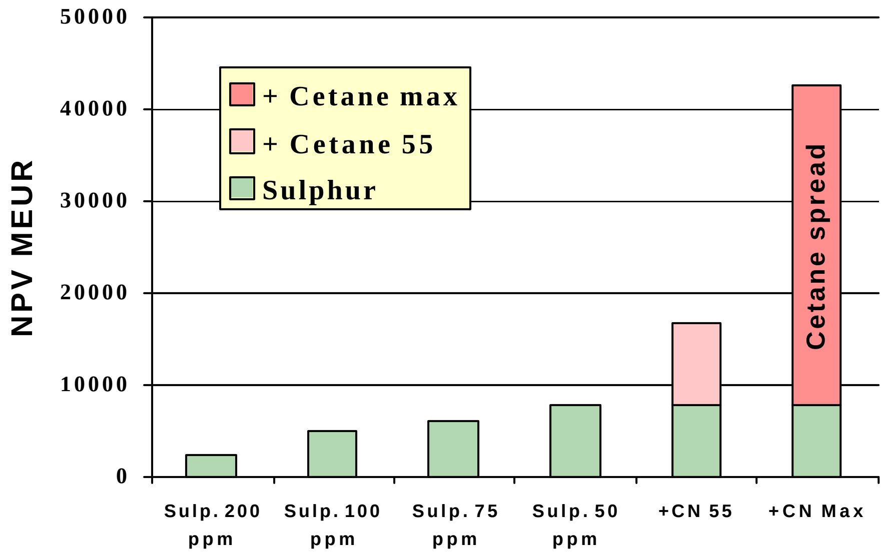


Figure B Diesel sulphur and cetane number constraint costs



1. INTRODUCTION

In 1995, CONCAWE published report no. 95/54, "Interim report on the European refining implications of severe reformulation of gasoline and diesel fuel". This contributed to the European Auto-Oil process to set a rational package of road fuel qualities, vehicle emissions standards and other measures to improve road transportation environmental performance from the year 2000. The techniques and data used in that analysis have now been refined and updated. The 1995 report started with fuel qualities based on the European specifications of 1995 including gasoline benzene 5% max (average 2.8%), diesel cetane number (CN)/Cetane Index (CI) 49/46 min, and sulphur (both fuels) 500 ppm max. This new report takes the more stringent specifications of the EU Council Common Position for 2000 as baseline and assumes that the effects of the resulting refinery measures are apparent in the actual qualities marketed.

The same basic refining planning philosophy is used in this study. It uses a fixed supply demand scenario (crude slate and product demands) with one marginal crude oil, heavy/high sulphur, which is considered to be representative of the anticipated crude oil quality available to the European oil industry for balancing supply with demand over the long term (2005 to 2020). A specially developed CONCAWE LP refinery model is used to identify the refinery process unit implications of varying road fuel qualities parametrically. Quality or volume dumping of unwanted components is not allowed. This provides a direct measure of the refinery processing inherent in any given increment of quality change and the energy consumption (CO_2 emissions) implications.

The technique is quite different from the planning normally done by individual refineries and oil companies for production planning. That sort of planning uses fixed refineries and variable inputs and outputs with the aim to find the most economic options. It requires knowledge of price data that are only known in the short term and that change differentially when refining and demand circumstances change. Using the long-range variable refinery (investment) with fixed input/output approach and reflecting the implications of measures based on refinery investments, costs can be predicted with a degree of accuracy, generally considered to be about +/-30%. It is generally accepted that the differential price elements between various crude oils and different products and qualities over the long-term should balance out with the costs of investment alternatives. The costs faced by an investing company and the costs faced by a non-investing company relying on the free markets will converge.

The analytical techniques used by CONCAWE have been refined. The previous work was done for the EU region as a whole and used four refinery configuration types: simple, cat cracking (CC), hydrocracking (HC) and both CC & HC. This reflected the fact that configuration is the main determinant of the level of costs required for any particular measure. For example, gasoline with low sulphur content is easy to make in a simple hydroskimming refinery, but is relatively very costly for a CC refinery. However, regional crude and product demand slate and the local quality requirements on products other than road fuels can be important too. For example, a region with lower than average heating gas oil demand and with more difficult cold properties has to be more selective in using components with good diesel properties in its base diesel fuel. That increases the burden of making diesel fuel quality changes. Methodology that ignores the regional variations always underestimates the costs of measures. The current methodology has retained the same four refinery configurations but has analysed seven regions (crude slate, product demands and qualities and the refinery numbers, types and capacities): Scandinavia, UK/Ireland, Benelux, Germany/Austria, France, Iberia and Italy/Greece. This approach also provides comparative cost data for participants in the Auto-Oil process.

The earlier work used three investment strategy scenarios, “Standalone”, “Consolidate” and “Network” to reflect the different possible ways oil companies could use to share and optimise investments and other resources. “Standalone” was the highest cost case in which individual refineries invest to solve their own problems even if it means changing category by adding, for example, a new small CC into a HC refinery to equip it for low aromatics gasoline. "Consolidate" was somewhat less costly in which refineries with insufficient configurations, for example simple and HC refineries in a low aromatics gasoline case, were allowed to close and the capacity of the remaining well-equipped refineries was increased by investment to compensate. "Networking" was by far the least costly, as it allowed components to move between refineries and when needed the construction of large process units that can be shared by a number of refineries, capturing economies of scale.

These had to be weighted using judgement. Now, the models themselves have been equipped with inbuilt rules that ensure consistency in choosing cost-effective moves of key intermediate components between refineries and the optimum number and sizes of new units required. The model distinguishes between process units that need to be installed individually in each location and those that can be shared. The choice between a shared or individual facility is prompted by the cost and complexity of the unit, component transfer and product distribution requirements.

A simplification made this time is to do the entire study using a single year, 2010, for the supply/demand basis. In the previous study, two years: 2000 and 2010 and two demand scenarios (HI & LO), were evaluated. However, no technical guidance was possible on how to weight the four sets of results to generate single values for net present value (NPV) suitable for use in cost benefit analysis of a wide range of competing and supporting combinations of measures. For this current refining cost evaluation, the detailed shape of the demand barrel is important but not nearly as important as the details of the refinery infrastructure: refinery number, sizes and types, by region. Apparently spare capacity in process units is not available to solve problems for free.

The year 2010 is considered an appropriate forward year to take for measures implemented from 2005 which, once decided, will be ongoing through the 15 or more years lifetime of the investments required by the measures. The investments calculated would not necessarily all be put in place in time for 2005. Some companies may choose to delay investment, taking free market options, for example, reducing production of tightly specified fuel. The resulting shortages of that fuel would feed back into higher prices or government fiscal action to stabilise fuel supplies so the investments ultimately become attractive in the EU or elsewhere. Whichever route any particular company chooses, the hypothesis adopted is that the overall costs on an NPV basis add up to about the same amount as if all had been invested in the first place.

The gasoline and diesel fuel quality changes considered in this study result in a range of separate and simultaneous changes on the quality parameters. These cover gasoline sulphur content to 50 ppm (mg/kg), aromatics to 35% by volume (vol.) at an olefins content of 18% vol. and diesel sulphur to 50 ppm and 55 cetane number (CN) and in 1 CN increments up to 58 CN if feasible. The starting point is the post 2000 Council Common Position. In report no. 95/54 for Auto-Oil-1, CONCAWE limited its studies to the corner cases of extreme reformulations for use as a realism check on the refining cost input into the process.

The inclusion of any particular package in CONCAWE’s current study matrix should not be used as an indication that there is environmental merit associated with it.

2. EARLIER WORK

The earlier CONCAWE work (report no. 95/54) established the costs of simultaneous reformulation of multiple specification parameters.

It should be noted that the extremes calculated by CONCAWE for sulphur of 100 ppm for gasoline and 50 ppm for diesel fuel, included the cost of gasoline aromatics at 25% vol. and diesel cetane number at 55/58. At the time, CONCAWE did not attempt to resolve the costs associated with independent but synergistic parameters, in particular diesel sulphur content and cetane number.

The anticipated final EU oil industry cost as a consequence of the AO1 resulting from the specifications from the Council Common position is estimated to be in the region of 20 billion EUR NPV using the European Commission AO1 cost methodology. The costs still to come will be spread over very many years and the actual costs may never be apparent except in retrospect. This factor makes them non-the less real and deserving of careful stewardship. The accumulative nature of the costs underlay the choice of net present value (NPV) to express the costs of AO1 measures. Some of the refinery investments associated with the AO1 measures can be deferred beyond year 2000 but not avoided forever. Some companies may choose to take supply alternatives and incur additional operating costs. The lower sulphur content crude slate currently available to the EU refining industry is not much more costly than the higher sulphur crudes also available but not currently taken up. This is enabling low sulphur products to be "borrowed from the bank" of crude quality that exists as a finite resource. Sometime in future, shortage of low sulphur will widen the cost differentials, probably overshooting in the process. The cost advantage will reverse and ultimately even more of the high sulphur crude will have to be processed which will make further investment deferral impossible.

CONCAWE's view of the cost of diesel fuel sulphur reduction up until recently were somewhat overstated because not enough allowance was made for emerging new advances of gas oil hydrodesulphurisation (HDS) technology (new catalysts, etc.). Following reviews with the catalyst manufacturers and oil company project experts, the cost of a high pressure (up to 60 bar) HDS unit, for example, has been revised downwards to M$75 for a 1.3 Mt/a unit from M$90 for a 0.73 Mt/a unit. At the same time, the desulphurisation rate achievable by such a unit has been increased to 99.5% from 97%. All the process unit project investment costs have been reviewed and updated if necessary (see ***Section 4.5***).

The simplified methodology of the 1995 study has understated the difficulty of meeting cetane numbers above 55 on the entire diesel fuel production within the bounds of demands for other products. Results now show that a uniform European level of 58 CN cannot be achieved with available refining technology. As CN is increased above 55 fewer regions appear to have a refinery infrastructure and demand pattern where it is feasible (mathematically) to employ the available processes to comply with the cetane specification and meet all the other demands placed on the refineries. However, the solution includes very extreme measures that do not appear to be viable. In particular, Scandinavia would face great difficulties above 55 CN.

3. SCOPE AND METHODOLOGY

The purpose of this study is to quantify the EU refining implications of universal reformulation of gasoline and diesel fuel individually and together in different quality packages. The starting position is the EU Council Common Position on the AO1 proposed year 2000 road fuels specifications.

Implications include investments, operating costs, energy consumption and carbon dioxide emissions. These are calculated using two tiers of LP models. The first tier uses a model with 7-regions/one single composite refinery per region. This is used to establish for each region the crude slate and inter-regional movements of products and components. These data provide a rational economic basis for running the second tier models. These comprise seven regional models with the refineries in each region modelled as four refinery configurations. The seven models are each run on a case study basis for every one of the combinations of gasoline and diesel qualities. The results of these case studies are then analysed to quantify the implications.

To model the refinery changes required for reformulation of the road fuels, the general approach taken is to require the same product demand on refineries to be met as in the 2010 base case. In the case of gasoline, the demand is defined in terms of constant transportation kilometres, thus making allowance for the lower heating value (LHV) effects of oxygen and aromatics (with higher carbon to hydrogen ratio). A similar approach for diesel fuel was considered. However, variations in the LHV on a mass basis over the range of aromatics and density reductions appear to be not significant. Thus providing the diesel demand is specified in terms of mass, no additional demand correction is required.

3.1. REGIONAL SUPPLY/DEMAND VARIATIONS

The 2010 demand call on EU refineries implied by the EC's pre-Kyoto oil demand forecasts for 2010 has been apportioned between the seven regions based on 1995 actual IEA/OECD data and the advice of STF-9 members with operations in particular regions. These demands were input into the 7-region/one refinery per region LP model together with region-specific quality data (e.g. gas oils cold properties). The model allows certain logically reasonable transportation linkages for products and certain components, which are known or expected to move inter-regionally at a cost. The LP was used to identify the optimum allocation of the crude slate and other inputs (see ***Section 4.1***) between regions and the product/component flows between regions.

Several runs were made with the 7-region/1-refinery model with different road fuels specifications. A case having gasoline with a low aromatics content and 50 ppm sulphur, diesel fuel at 50 ppm sulphur and 55 cetane number, was chosen. Choosing a non-severe case might have faced regions with too difficult a crude/production slate to produce feasible severe case study results. Too severe a case could tend to give a basis that underestimated the implications of non-severe case studies. The key features of this planning basis: crude slates, other imports and exports, production slates and inter-regional component and product movements are shown for EU-15 and for each of the seven regions in ***Appendix 1***.

This provides the crude slate, other inputs and product/component imports and exports as a basis for running the seven regional 4-refinery type LP models. The corresponding output supply/demand balances and inter-refinery component movements from the regional models for the base AO1 specification case by region are shown in

Appendix 2. The EU-15 table also in ***Appendix 2*** is the aggregation of the seven regions.

It should be noted that the crude runs in **Appendix 2** are higher than in **Appendix 1** because the levels of gasoline exports from EU-15 are higher and imports of MTBE are lower, for LP-model tuning reasons. The regional demands are the same with the exception of gasoline where there is a small apparent difference arising from the specification of the demand on a constant transport km basis that varies the tonnage somewhat depending on the aromatics and oxygen levels found by the different LP models used to generate them.

For the diesel cetane number part of the study, the appropriate regional base cases (1404) were re-optimised with an improved representation of the cetane performance of dearomatisers and hydrocrackers and with the diesel sulphur specification of 50 ppm and the gasoline Year 2005 specifications included. This facilitates the inclusion of the much lower cost of adding a dearomatiser stage when the hydrodesulphurisers can achieve 50 ppm. Thus the details of the supply demand balances differ somewhat (not shown in ***Section 4*** or ***Appendix 2***), in particular the allocation of additional hydrocracking to the various regions which are recorded in ***Table 1***.

The results from these seven individual region sets of model runs are used to assess the costs and energy/carbon dioxide emissions of the various road fuels qualities packages.

The costs, etc. in each region are then aggregated to provide the overall implications for all the quality (characteristics) cases (road fuels packages) studied.

3.2. REFORMULATION IMPLICATIONS FOR DIFFERENT REFINERY TYPES

Different refinery types will face different challenges, and investment burdens, to meet the proposed fuel reformulations.

Simple Refineries

The major problem for simple refineries is to meet the gasoline aromatics specification. Simple refineries have typically blended gasoline from reformate, light virgin naphtha and butane and this has resulted in a high aromatics content. The steps that they can take to reduce aromatics are either to reduce reformer severity, or the amount of reformate in gasoline blends, or to dilute the aromatics with a low aromatic blending component. Reducing reformer throughput or severity is undesirable as it reduces octane that must be replaced by the import of an octane component such as MTBE. It also reduces the hydrogen produced by the reformer and most refineries of this type do not have access to an alternative source of hydrogen.

Many simple refineries export light virgin naphtha as chemical feedstock. The option they have for diluting aromatics without resorting to imports, while still meeting the gasoline octane requirement, is to invest in a light naphtha isomerisation unit to upgrade their light virgin naphtha. However this would increase their gasoline production at a time when there is already surplus gasoline in Europe.

The other dilution option available to simple refineries is to take advantage of the low sulphur and olefin content of their gasoline by importing cat gasolines for blending. This helps dispose of a difficult component for the cat cracking refineries and has the effect of transferring some gasoline production from the cat cracking refineries to the simple refineries.

It is difficult for a simple refinery on its own, without importing cat gasolines, to solve its gasoline quality problems without investing in a cat cracker. As a cat cracker increases the production of gasoline, few refineries will find this attractive and most will become dependent on the purchase of blending components. While this may be feasible for refineries in major refining areas or ones with coastal access, it may be difficult for some to obtain reliable economic supplies of the components they need.

The simple refineries would also face problems meeting a high diesel cetane specification as their diesel is produced exclusively from straight run gas oils. The cetane of these gas oils depends very much on the source crude but few crudes have gas oils with a cetane number of more than about 52. Therefore, as well as being desulphurised, these gas oils would have to be processed to saturate the aromatics and increase the cetane number. Aromatic saturation consumes large quantities of hydrogen and this requires the reformer to continue to be operated at high throughput and severity. The alternative of hydrogen generation would be a major investment burden for this type of refinery.

Cat Cracking Refineries

Cat cracking refineries are faced with difficulties in meeting both gasoline and diesel specifications. Light cat gasoline has high olefin content and relatively high sulphur content, while heavy cat gasoline has high sulphur and aromatic contents.

Cat gasoline can be desulphurised by a combination of mercaptan extraction from light cat gasoline, reforming intermediate cat gasoline and selective desulphurisation of heavy cat gasoline. The sulphur content of cat gasolines is significantly reduced if the cat cracker feed is hydrotreated but intermediate and heavy cat gasolines may still need desulphurisation to meet very low gasoline sulphur specifications.

The high olefin content of gasoline from cat cracking refineries can be addressed in a number of ways. The export of light cat gasoline to simple or hydrocracking refineries is one mechanism that also helps to reduce gasoline aromatics in those refinery types. The C_5 olefins in light cat naphtha can be converted to TAME, a high octane gasoline blending component containing no aromatics or olefins. The C_4 olefins from a cat cracker can also be used to produce either MTBE or alkylate, both of which are high quality gasoline blending components. However in many cat cracking refineries these C_4 olefins are used as chemical feedstocks and hence there is an additional cost associated with moving them into the gasoline pool.

The major distillate problem for cat cracking refineries is the disposal of light cat gas oil as these streams have a high density and poor cetane. The basis prior to this study leaves it possible to blend some light cat gas oil into diesel but this will not remain possible once the diesel density is reduced and the cetane number is increased. Light cat gas oil has been blended to heating oils and used for fuel oil flux but the demand for these products is falling and the density specification of heating oils limits the quantity of light cat gas oil that can be used. One potential disposal route for light cat gas oils is to route them to a hydrocracker, but they would tend to be converted towards lighter products at a time when there is a need to use hydrocrackers for the production of high quality diesel components. Light cat gas oil quality can be improved by processing in an aromatic saturation unit but the resulting product only has a cetane number in the low 40s which is still too low to be blended into reformulated diesel.

A cat-cracking refinery can solve most of its gasoline and diesel quality problems with investment. Disposal of light cat gas oil is the one area where it may attempt to export to a hydrocracking refinery instead of investing in its own hydrocracker. However it is not likely that a hydrocracking refinery would find this an attractive feed when producing diesel to a high cetane specification.

Hydrocracking Refineries

Hydrocracking refineries are well placed to meet the diesel specifications but have similar difficulties to the simple refineries in meeting gasoline aromatics. Hydrocrackers produce naphtha with a comparatively low octane and hence it must be reformed before it can be blended to gasoline. This has the effect of increasing the quantity of highly aromatic reformate to be blended to gasoline.

Isomerate is the only low aromatics component that can be produced in a hydrocracking refinery since it does not produce light olefins that can be used to produce alkylate, MTBE or TAME. As for simple refineries, hydrocracking refineries are likely to be dependent on the import of cat gasolines to dilute the aromatics in their gasoline.

As in the case of simple refineries, it is difficult for a hydrocracking refinery to solve its gasoline quality problems without either becoming dependent on the purchase of gasoline blending components or investing in a cat-cracking unit. The installation of a cat cracker would not be an attractive investment for many hydrocracking refineries. Hydrocrackers and cat crackers use similar feedstocks and hence the installation of a cat cracker would result in the existing hydrocracker being spared.

Hydrocracking refineries are better positioned to meet the reformulated diesel specifications as the hydrocracked distillate has a high cetane. Refineries with a recycle hydrocracker may produce a stream with a cetane number of up to 60. Blending this with straight run gas oil and the use of cetane improver allows a high diesel cetane specification to be achieved. The hydrocracked distillate from a refinery with a once-through unit has a lower cetane and this may still require the saturation of aromatics in straight run gas oil to meet a high cetane specification.

Cat Cracking and Hydrocracking Refineries

Refineries having both a cat cracker and hydrocracker are in the best position for meeting the new specifications as they can take advantage of the synergies offered by these two units. However there are relatively few refineries of this type.

Even in this type of refinery there would be processing conflicts. There would be pressure to maintain a high throughput on the cat cracker to produce cat gasolines to dilute gasoline aromatics. However this would increase the production of light cat gas oil with poor cetane quality which may have limited outlets. Dedicating the hydrocracker to heavier feeds to maximise the production of high quality diesel puts the hydrocracker and cat cracker in direct competition for the same feed that has limited availability.

3.3. LOCALISED IMPLEMENTATION OF REFORMULATION IS ADDRESSED ONLY BY REGIONS AS A WHOLE

The methodology represents the 90 refineries[1] in the EU in 1998, which differ widely in type, degree of conversion achievable and sizes, as a 7x4 matrix, i.e. as 28 refineries (26 actually as 2 regions lack refineries in one category each). The capacities of each

[1] An additional 4 small refineries are included in the capacity/cost data

type of process unit are aggregations of the capacities in all of the refineries in each of the four configurations for each of the seven regions.

This methodology provides a snapshot of the costs that will be typical in each region when implementing the quality/characteristics changes universally for each of the road fuels individually and both together. When both fuels are changed, either synergy or antagonism between the changes can exist depending on the measure, e.g. in general, gasoline and diesel sulphur are synergistic and give lower combined costs; gasoline aromatics and diesel cetane tend to be antagonistic at high CN levels and give higher combined costs.

Table 1 Number and capacities of refineries by region and type in 1998.

	Scandinavia	UK/ Ireland	Benelux	Germany / Austria	France	Iberia	Italy/ Greece	Total
Simple	4	2	2	2	1	3	10	**24**
Cat Cracking (CC)	1	7	3	10	11	6	6	**44**
Hydrocracking (HC)	0	1	3	3	0	1	2	**10**
Both CC & HC	2	1	1	1	1	1	5	**12**
Total No.	**7**	**11**	**9**	**16**	**13**	**11**	**23**	**90**
Total Capacity (Mt/yr)	**39.2**	**94.1**	**91.1**	**118.1**	**89.4**	**81.1**	**132**	**645**
Added HC by 2010(Mt/yr)	-	1.5	-	-	2.5	5.5	-	**9.5**
Added HC by 2010(Mt/yr) CN study only	1.0	2.7	-	-	0.4	-	3.4	**7.5**

Table 1 shows the current refinery types in 1998. Except for the cetane number part of this study, the 2010 planning basis (2010 demand and Council Common Position AO1 year 2000 road fuels specifications) adds seven hydrocrackers totalling some 9.5 Mt/yr, which are allocated by the LP. One CC refinery in UK/Ireland becomes CC+HC, in France two CC become CC+HC and in Iberia two simple become HC and two CC become CC+HC. The cetane number study basis adds 5 hydrocrackers totalling 7.5 Mt/a, which the LP allocates such that one simple refinery in Scandinavia becomes HC, in France one CC becomes CC+HC, in Italy/Greece two simple become HC and in UK one CC becomes CC+HC.

The study results can not be interpolated to infer the cost of reformulating only part of the road fuels production. In general, some refineries could make small proportions, e.g. 10%, of either road fuel to very severe specification levels with little apparent cost. This may involve exploiting some particular circumstance, which happens to favour a specific property in a particular refinery or region. Examples are gasoline sulphur in Sweden and gasoline aromatics in UK complex refineries with large CCs. It is also possible to produce limited amounts of reformulated fuel, e.g. UK city diesel, by the use of selected components. However this results in the quality of the remaining production being reduced. The current fast introduction of 50 ppm sulphur diesel, with a tax incentive of 3 pence a litre, is made possible by a stronger reliance on low sulphur crude, careful selection of blending components and imports of low sulphur diesel with exports of the standard diesel grade to the continent. The total production of road diesel is likely to decrease. The tax incentive supports internal reallocation of components, procurement of extra low sulphur crude and additional logistics costs of importing quality from the continent (imports and exports) whilst deferring extra investments for the moment.

3.4. BASE CASE AND REFORMULATED PRODUCT QUALITY PACKAGES

The base case road fuels environmental qualities are specified at the EU Council Common Position values for year 2000, see ***Table 2*** In general the overall average qualities in the base case have giveaway versus the specification after allowing for blending tolerances. Such giveaway is a characteristic of the production of certain of the refinery types. The exception is diesel fuel sulphur content where all refineries try to produce as high as the specification allows. The CEN specifications for other properties are met and appropriate cold properties for diesel (and gas oil) are set for north, mid and south regions. Gasoline %E150 is not specified but is back calculated for use in emissions effect calculations.

Table 2 *Key b*ase case road fuel specifications (AO1) and calculated average qualities 1)

Gasoline	**Specification**	**Average**
Sulphur content (ppm, mass) max.	150	124
Aromatics content (%, volume) max.	42	37.8
Olefins content (%, volume) max.	18	11.8
Diesel		
Sulphur content (ppm, mass) max.	350	315
Cetane Number, CN min.	51	52.3
Density max.	0.845	0.834
Polyaromatic hydrocarbons, PAH (di+, % mass)	11	About 5-6

1) Council Common Position, October 1997

It should be noted that the gasoline aromatics, diesel PAH and most particularly gasoline olefins averages come from individual refinery data that are widely spread around the mean values. Part of the improvement between average and specification is due to the tolerances added to the modelled specification value (see below). The remainder is from the refinery configuration types that naturally have give-away on the particular specification point. If data are input into, for instance vehicle emissions models, the starting emissions levels should be based on the average qualities rather than the bare specification values.

The quality/characteristics of the packages of the two road fuels are mapped in ***Table 3.***

Table 3 Gasoline and diesel fuel base case and reformulated packages

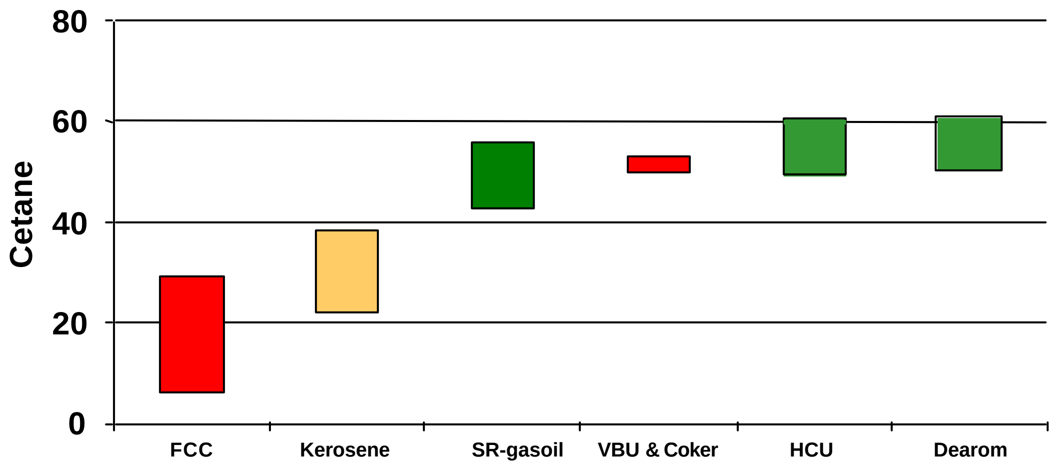
			Gasoline Cases					
		Sulphur	150	100	50	150	100	50
		Aromatics	42	42	42	35	35	35
Sulphur	PAH	Olefins	18	18	18	18	18	18
		Cetane						
Diesel cases								
350	11	51	Council 2000 09v0	Stf-9 10v0	Stf-9 11v0	Stf-9 12v0		Stf-9 14v0
200	11	51	Stf-9 09v1			MEP 2000 **		
100	11	51	Stf-9 09v2					Stf-9 14v2
75	11	51	Stf-9 09v3					
50	11	51	Stf-9 09v4		Stf-9 11v4			Council 2005 14v4 & 1404
50	11	55	Stf-9 09v5					Stf-9 1405
50	11	56 if feasible	Stf-9 09v6					Stf-9 1406
50	11	57 if feasible	Stf-9 09v7					Stf-9 1407
50	1	58 if feasible	Stf-9 09v8					Stf-9 1408

In accordance with standard practice, blending tolerances to allow for test method reproducibility and blending margins are imposed on all these properties except cetane. The margins applied are 90% of the specification for sulphur (e.g. 315 ppm blending target for a 350 ppm specification), 2% vol. for gasoline aromatics (e.g. 33% vol. blending target for a 35% specification) and 1% vol. for olefins.

The cetane problem

For cetane, there is the added complexity that cetane correlations based on density and distillation parameters differ for different configuration refineries and at different cetane levels. This is because of the wide variation in the quality of the crude processed and in the type and operating conditions of the process plants affecting the cetane value (see ***Figure 1***). There is no reliable single industry-wide relationship. CONCAWE represented cetane levels from distillation and density parameters according to the ASTM D976 method. For gasoils from hydrocracking and VGO desulphurising, the cetane levels are linked to processing conditions and for dearomatised gasoils the cetane quality is made crude source dependent, related to the paraffinic and aromatic content of the feedstock.

Figure 1 Cetane values of principal blending components



The tendency for LP solutions to over optimise high cetane component selection has to be taken into account. CONCAWE approached this by calibrating its LP model results with the expected year 2000 diesel fuel quality. The current European average for cetane number (CN) is about 51. Parts of current diesel production already contain cetane-improving additives, thus the additive-clear pool is expected to be 50 CN. A study-specific CN calibration side study made with the 7-region and the single-region models shows that the single region model can blend diesel fuel with a CN of somewhat above 51 CN and the seven regional models with 50-51 CN, without major new investments in primary CN-improving processes beyond those required for demand growth till year 2010. This demonstrates that the models can find numerically feasible solutions by full segregation of the blending components with the best cetane, etc. A working refinery cannot achieve this level of segregation nor such high cetane levels of components on a day by day basis due to the unrepresented but real crude slate variability effects and feedstock variations in processes. In reality, refineries have to compensate as far as possible by using cetane-improving additives, or reduce the production of diesel and also increase its working inventory.

Based on the calibration study and using the “average versus specification” margin of 2 CN points derived for the AO1 study methodology it is concluded that the model results reflect three additional CN units on average gained by adding the maximum practical level of CN improving additive. Thus the LP results for diesel blends with CN specification of 51 and above are considered to reflect significantly increased use of additives at the maximum average practical level. This level of use of additives in the blends to increase CN is assumed to be limited by practical/economic factors. The limiting levels of cetane number found are the maximum specifications achievable with the processing packages identified by the study.

Additional research is required to develop a better blending methodology and improve the process data for CN in the 50 to 60 range, taking additive and more realistic effects of crude origins and dearomatisation and hydrocracking severities into account, so as to remove the need for the compensation of model results. Refineries also require to pay attention to measurement and testing regimes and developing a more consistent test itself if CN is to be closely controlled in future.

4. BASIS FOR REGIONAL REFINERY SIMULATIONS

The starting point for this study was the CONCAWE 1996 planning cycle original case supply/demand plans that two years ago were discussed with various consultants actively involved in long range industry refining planning. The product demands were based on the DG-XVII 2020 study conventional wisdom case for 2010. The demand basis was subsequently changed in line with DG-XVII's pre-Kyoto total oil and petroleum transportation fuels demands forecast for 2010 (see *Section 4.1.*) The crude slate (see *Section 4.2.*) and other refinery input is based on the original CONCAWE assumptions, as are imports of gas oil and imports of condensates/LPG/ethane as chemicals feed. Gasoline exports from the EU to other OECD countries are allowed to increase from the originally used 5 Mt/a to 10 Mt/a (Benelux 5 Mt/a, France 3Mt/a, Italy/Greece 1 Mt/a and UK 1 Mt/a). MTBE imports find their own (lower) level totalling 0.5 Mt/a versus 4.5 Mt/a, also for tuning reasons.

4.1. 2010 PRODUCT DEMAND CALL ON EU REFINERIES

The DG-XVII Pre-Kyoto basis has 349.6 Mt/a transport fuels demand, ***see Table 4***. This represents growth versus 1995 of 73.8 Mt/a. The 1995 transport fuels total 275.8 Mt/a, included LPG 2.8, Gasoline 121.0, AGO 113.4, Jet 32.5, and no Biofuels. The Pre-Kyoto gross inland oil consumption is forecast to be 649.4 Mt/a, up 75.4 Mt/a versus 1995, see note (3) below ***Table 4***.

Table 4 Transportation fuels demands and total oil consumption 1995 and 2010 pre-Kyoto (Mt/a)

	DG-XVII 1995	CONCAWE Original 2010	DG-XVII Pre Kyoto 2010	CONCAWE Pre Kyoto 2010
LPG	2.8	3.0	13.0	3.0
Gasoline	121.0	146.3	149.2	127.2
AGO	113.4	127.4	134.8	155.0
Jet	32.5	45.0	38.3	46.4
Gas oil		10.0		10.0
Other oil	1.2	-	1.5	7.1
Bio	0	11.0	3*	1.0
Other non oil	5.0		9.8	
TOTAL	**275.8**	**342.7**	**349.6**	**349.6**
Total oil consumption	**600** (1)	**658.7** (2)	**684.4** (3)	**642.4** (4)

Assumes 15% of DGXVII bio-gasoline and bio-diesel is biomass-derived fuels.

(1) Gross inland oil consumption 574 Mt/a plus 26 Mt/a international marine bunkers.

(2) Total oil demand includes 5 Mt/a export gasoline and international marine bunkers

(3) Gross inland oil consumption 649.4 Mt/a plus 35 Mt/a international marine bunkers

(4) Total oil demand includes 5 Mt/a export gasoline and international marine bunkers. Comprises 587.3 Mt/a demand call on refineries (see ***Table 5*** and ***Appendix 1***) plus 55.1 Mt/a refinery fuel and loss.

Table 5 CONCAWE Pre-Kyoto 2010 product demand call on EU refineries (Mt/a) used for the 7-Region LP model runs.

	Scan-dinavia	UK & Ireland	Benelux	Germany & Austria	France	Spain & Portugal	Italy & Greece	**Total System**
Products Mt/a								
Refinery Gas		0.1	0.1	0.7	0.1	0.1	0.1	**1.2**
LPG	0.5	1.4	1.8	4.1	2.8	3.2	4.5	**18.3**
Chemical feed	0.7	1.1	3.8	7.9	4.0	3.6	7.4	**28.5**
Gasoline Exp. 93			5.0					**5.0**
Gasoline Bio 94.5				5.2	5.0	2.0	4.8	**17.0**
Gasoline UL 95H (1)	8.4	26.9	1.6	17.3	0.5	2.4		**57.1**
Gasoline UL 95L (1)			9.2	3.1	11.2	11.7	18.0	**53.2**
BTX feed		1.0	1.0	1.8	1.0	1.0	1.0	**6.8**
Jet & kerosine	2.7	12.6	5.3	4.9	7.0	8.0	9.4	**49.9**
Auto diesel city	2.0							**2.0**
Auto diesel north	5.0			3.1				**8.1**
Auto diesel mid	3.1	19.6	16.8	21.2	24.3		6.0	**91.0**
Auto diesel south		2.9				24.0	27.1	**54.0**
Ind. Gas oil north	8.1			0.5			1.1	**9.7**
Ind. Gas oil mid		5.0	10.7		12.1		3.8	**31.6**
Ind. Gas oil mid (Germany) (2)			1.9	27.5				**29.4**
Ind. Gas oil south						5.3	4.0	**9.3**
Fuel oil 0.6%	3.3	0.4	0.6				0.2	**4.5**
Fuel Oil 1%	2.9	5.6	1.0	5.7	1.8	1.6	8.8	**27.4**
Fuel Oil 2%		2.0			1.8	3.6		**7.4**
Fuel Oil 2.5%		0.9			5.9	3.6	2.1	**12.5**
Bunker	0.5	1.7	14.5	1.7	2.1	3.6	5.1	**29.2**
Lube oils	0.1	1.9	0.6	1.2	1.4	0.4	1.3	**6.9**
Low S coke		0.7		1.0			0.2	**1.9**
High S coke				0.1		0.5	0.5	**1.1**
Sulphur	0.2	0.5	0.9	0.9	0.5	0.5	0.9	**4.6**
Heavy residue							3.0	**3.0**
Bitumen	1.4	3.0	0.9	3.5	3.0	2.7	2.3	**16.8**
Total	39.0	87.2	75.8	111.3	84.6	77.8	111.6	**587.3** (3)

Notes:

(1) Premium unleaded gasolines are made to either 60 kPa RVP (L) or 65 kPa (H) as a token reflection of the in-service requirements of North versus South. In the basis used for the regional models, the Premium Gasoline Bio demand was consolidated into Premium Gasoline UL 95 demand when it became apparent that DGXVII's ambitions for biofuels had reduced. Also, the RVP distinction was dropped and all regional models use 60 kPa RVP.

(2) The Industrial gas oil mid grade is made to 0.86 max density for Germany/Austria and 0.88 max elsewhere

(3) See table 4, note 4

The allocations of crude slates and other inputs and inter regional product and component movements determined by the 7-region model are used as input for the seven regional LP models. The CONCAWE Pre-Kyoto Basis road fuels qualities similar to case 14y5 (see ***Table 3***) data are used. Total oil demand for this case is 642.4 Mt/a (587.3 Mt/a demand call on refineries plus 55.1 Mt/a refinery fuel and loss). Hence the forecast refinery utilisation, having allowed for some upward nameplate capacity creep in some refinery types in some regions, is about 95%. In essence, the refining capacity is fully utilised.

The CONCAWE pre Kyoto basis reflects the 349.6 Mt/a transport fuel demand but is not consistent with DG-XVII's advised high gasoline/low diesel growth rates. CONCAWE's oil industry reviewers believe the current EU pattern of diesel fuel growth with gasoline demand at around its current plateau level to be a more realistic basis. A sensitivity analysis has been carried out for the higher gasoline/lower diesel demand basis showing that this currently unresolved difference does not materially affect the study findings.

4.2. CRUDE SLATE

The EU crude slate development assumed for the CONCAWE 1996 planning cycle is shown in ***Table 6***. It is anticipated that heavying up of the crude slate will start to occur after 2000. Consequently the sulphur content of the crude slate increases progressively. A further trend that is anticipated is a continuing swing from light low gravity low sulphur crudes to light higher gravity low sulphur crudes such as those found in many of the newer North Sea discoveries. The higher gravity is a consequence of the naphthenic nature of these crudes and the result is a lower natural cetane in the gas oil cuts.

Throughout the study, the assumed oil industry marginal crude is heavy (high residue yield) high sulphur characterised by Kuwait (KW). Similarly, Brent Mix (BT) is used as a surrogate for all the light (low residue yield) low sulphur crudes that are also low density that will be in the slate. Light low sulphur but high density (naphthenic) crude is characterised by Nigerian Forcados (NF), and medium heavy (medium residue yield) medium-sulphur by Iranian Light (IL). Process naphtha and condensate imports are characterised by Algerian Condensate (AC).

Table 6 EU crude slate development from 1995 to 2020

CRUDE SLATE				EU15 1995	EU15 2000	EU15 2005	EU15 2010	EU15 2015	EU15 2020
	Density	Atm. Resid.	API						
		(wt %)	(DEG)	wt%	wt%	wt%	wt%	wt%	wt%
Light LS (BT)	0.835	38	38	50	50	40	30	25	22.5
Lt/Nap LS (NF)	0.89	36	27	5	5	10	15	15	12.5
Med MS (IL)	0.853	44	34	20	20	20	20	20	20
Heavy HS (KW)	0.868	51	32	25	25	30	35	40	45
Total				100	100	100	100	100	100
Average Sulphur		(wt %)		1.06	1.06	1.20	1.28	1.39	1.51
Average API		(DEG)		35.11	35.11	33.93	33.42	33.10	33.04
Average Density				0.8496	0.8496	0.8558	0.8584	0.8601	0.8603
Calc Atm Resid Yield		(wt %)		42.4	42.4	43.0	43.5	44.1	44.8
				1995	**2000**	**2005**	**2010**	**2015**	**2020**
Light LS (BT)		Mt/a		279	293	239	182	154	141
Lt/Nap LS (NF)		Mt/a		28	29	60	91	93	78
Med MS (IL)		Mt/a		112	117	120	122	124	125
Heavy HS (KW)		Mt/a		140	146	180	213	247	282
TOTAL		Mt/a		**559**	**585**	**599**	**608**	**618**	**626**

The 2010 crude slate with KW marginal is the one actually used for this study.

The trends over time are considered to be robust based on the assumption that the actual crude oil reserves today represent a sizeable sample of the crude available in the future from existing reserves and new discoveries. However, the timing and the rate of progress of the trends are quite uncertain for complex commercial and political reasons. In this outlook, the variable crude (the marginal KW) is postulated to remain the same one in all years. Hence as long as the nature of the overall trend stays the same, the results should not be particularly sensitive to the accuracy of the trend rate assumptions. In this CONCAWE basis, the supply demand trends are antagonistic to the proposed product quality changes for sulphur content and broadly neutral for cetane number.

The allocation of the single marginal crude, KW, means that all the refinery fuel, hydrogen feedstock and loss implications of the LP case differences are shown in terms of KW use, net only of the other supply mechanisms described in ***Section 4.3***, below. Using mass balance principles, carbon in is equal to carbon out. Hence the overall CO_2 emissions effects can be calculated directly using the carbon content of KW, i.e. 86% m/m.

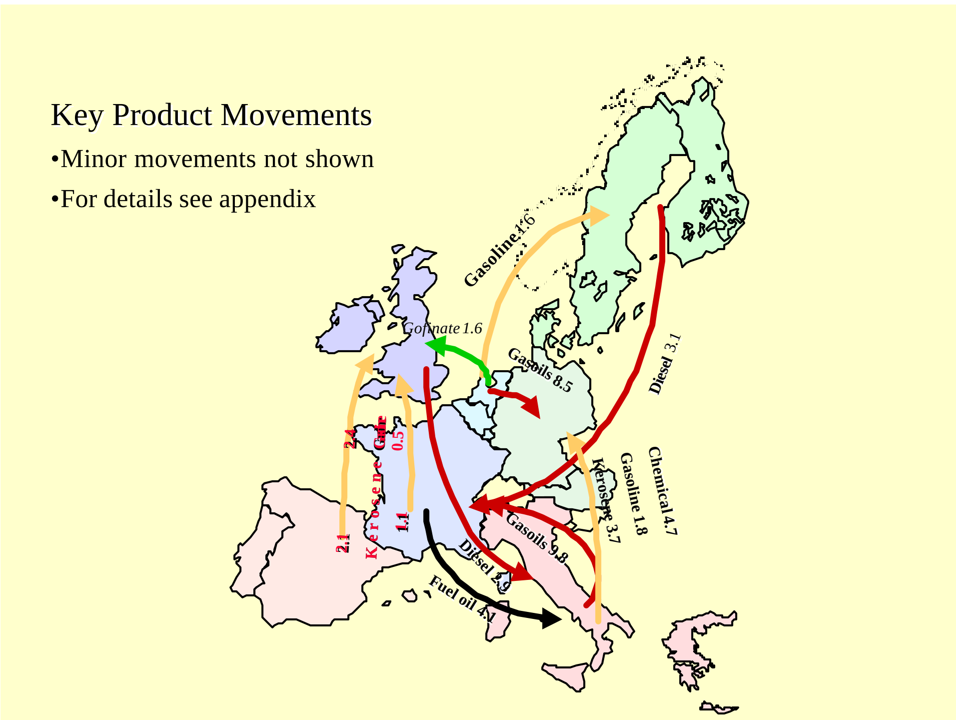
4.3. OTHER SUPPLY MECHANISMS

Imports of methanol are provided for as co-feedstock for refinery MTBE and TAME plants and additional imports of MTBE from outside of the EU-15 oil refining industry are permitted. The investment and energy effects are not included in the LP-model and are accounted for at the analysis model (Lotus IMPROV) stage based on the amounts used in the LP solutions.

In the planning basis for this study the EU-15 refineries have spare gasoline capacity in the form of spare cat cracking capacity. Consequently, the LP model finds it unattractive to bring in the imported MTBE when the price is set at the level considered necessary to provide the required rate of return (for example 1.7 times premium gasoline price) to bring about the construction of new world scale methanol and MTBE plants which would be required to secure the availability of large amounts of imports. For study purposes, the MTBE price is set at a level (generally 1.3 times premium gasoline price) at which point it marginally enters or is about to enter in the regional base cases.

4.4. INTER-REGIONAL MOVEMENTS.

Figure 2 Inter regional movements of transport-related products and components.



The inter-regional movements from the 7-region/single refinery per region LP model results (see ***Appendix 1***) are carried forward into the basis for the seven regional 4-

refinery LP models, thus modifying the regional demand call on refineries to match the demands with the refinery production potentials.

These product movements illustrate the character of the regional demands. Germany/Austria is short of refinery capacity versus its demand. France is short of diesel fuel and long on gasoline. The UK/Ireland is short of jet fuel and long on diesel/gas oil. Scandinavia is short of gasoline and long on diesel. Benelux, Iberia and Italy/Greece have refinery capacity to supply other regions. Additionally, UK/Ireland is short of cat feed and Benelux provides 1.6 Mt/a desulphurised cat feedstock (gofinate).

4.5. GASOLINE REFORMULATION MECHANISMS

As discussed in ***Section 3.2*** the different refinery types face different challenges on gasoline properties. It is assumed that certain gasoline components can move between refinery types, incurring transportation costs, to balance out quality shortfall/giveaway positions. The movements permitted are Alkylate and the light (LCG), medium (MCG) and heavy (HCG) cat gasolines. These components reduce the aromatics level for the receiver, and the cat gasolines relieve the sender of part of its sulphur burden. Thus the model selects the most economic choices between meeting the quality constraints by component networking and moving gasoline production towards the refinery types in the more favourable situation.

Sulphur enters gasoline only with the cat cracked gasolines and the returns of by-products from chemicals production. Reduction of the sulphur in both streams first requires additional fractionation into LCG, MCG and HCG cuts; an additional fractionation step for most refineries.

The LCG cut is the least sulphurous and can be treated to remove mercaptan sulphur in an extractive caustic process. Two LCG cuts are modelled: 75°C and 90°C final cut point (FCP). The process removes 90% of the mercaptan sulphur (63% and 59%, respectively, of the total sulphur).

The MCG cuts 140°C FCP can be desulphurised (and the olefins eliminated) by cat gasoline reforming. Investment is required to modify the existing cat gasoline splitting and naphtha reformer feed pretreatment facilities and make other reformer peripherals changes. This process removes essentially all of the sulphur, with an octane credit of 8 to 11 MON and aromatics increase by some 40% to 46% v/v, depending on the cut of MCG and the reformer severity.

The HCG cut between MCG and light cat gas oil (LCO, at 180°C or 221°C initial cut point, ICP) contains the bulk of the sulphur particularly in the heavy end. Thus gasoline desulphurisation can be achieved by under cutting the HCG. The base case already uses up this mechanism. HCG (and the heavy cut of Chemicals Returns) can be desulphurised by selective hydrotreating, or by severe hydrotreating with greater octane loss. Some 96% of the sulphur is selectively removed with octane loss of around 3 RON and 1 MON. Sulphur removal of 99.5% or more can be achieved, however at the expense of reduced selectivity and increased octane loss.

Desulphurisation of the Chemicals Returns is modelled as if it was a full range cat gasoline with its own quality characteristics and is split and desulphurised using the same mechanisms.

The contribution of the cat cracker to gasoline sulphur content can also be greatly reduced by hydrodesulphurisation of the high sulphur cat feed streams (gofiner process). Some 95-96% desulphurisation of the cat feed and 17% to 30% conversion to products lighter than the feed is achieved. Furthermore, the remaining sulphur is preferentially distributed in streams other than the cat gasolines by comparison with the sulphur distributions exhibited with virgin cat feeds.

Sulphur is also reduced to some extent by dilution, reducing the proportion of the cat cracked gasoline in the blend, i.e. lower cat plant throughput and/or higher amounts of synthesised components such as alkylate and MTBE.

This study is done at constant benzene specification. Therefore, the benzene control mechanisms in the model play little part in the differential results of the cases.

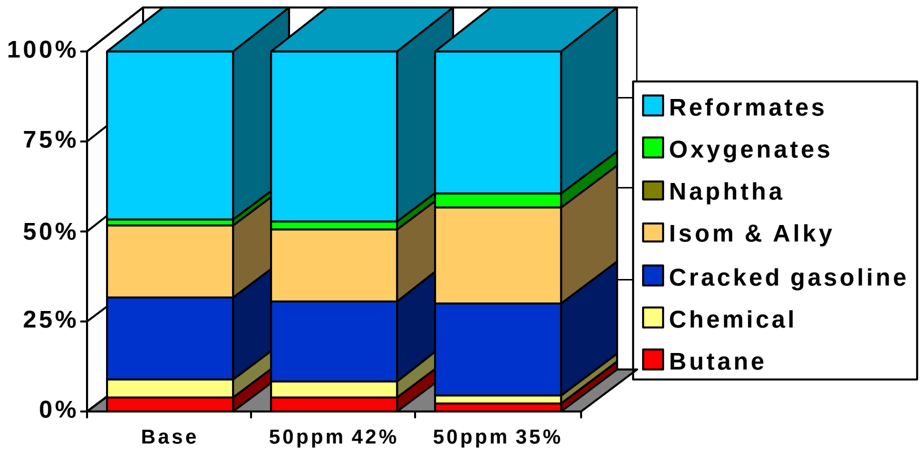
Aromatics are essential in commercial gasoline to provide octane. With the growing pressure put on octane by the reduction of aromatics including benzene on the one hand and on fuel economy on the other, it is assumed that the Super unleaded grade and the remaining Regular grade (Germany) are discontinued by 2005. The production of the Super grade could seriously impact the scope for gasoline aromatics reduction.

Therefore, for the purposes of the current study, the EU gasoline market is modelled as 95/85 (min) RON/MON Europremium. It should be noted that in the USA the high demand for the 87(RON+MON)/2 grade there, i.e. about 3 octane lower, is a significant factor in lowering aromatics levels. Aromatics content (% vol.) can be decreased by reducing the proportion of whole reformate or the light and heavy (particularly) products from a reformate splitter and HCG in the gasoline. All the other components have much lower aromatics contents but may also have lower octanes. Additional isomerate, alkylate, refinery MTBE and virgin naphtha can feature in low aromatics cases. As the lower levels are targeted, imported MTBE as well as assisting the dilution process brings additional octane to the pool, which helps incorporate greater proportions of the low octane diluents.

Olefins in gasoline come from the cat-cracked gasolines, particularly LCG. The LCG olefins can be converted into tertiary amyl methyl ether in the TAME unit. Additionally, unsaturated C4s that could also be blended into gasoline in small quantities can be converted in alkylation plants.

An example of what happens to gasoline blending pool components is shown in ***Figure 3***.

Figure 3 Typical gasoline component changes as sulphur and aromatics reduce.



This demonstrates the change found for Iberia as the gasoline quality is progressively restricted. Existing reformers, and less obviously anticipated, cat crackers, become substantially under-utilised. Isomerisation of light naphthas and alkylation grow. Isomerisation is constrained by light naphtha availability and the gasoline %E70 max specification. Alkylation and also additional scope for refinery MTBE production become severely constrained by the lost CC throughput. Thus a significant increase in imported oxygenate may become essential to meet a 35% aromatics specification.

4.6. DIESEL FUEL REFORMULATION MECHANISMS

The assumed permitted diesel component movements between refinery types comprise hydrocracker gas oil to CC and simple refineries and in the reverse direction hydro-desulphurised light cat gas oils (medium pressure (MP) or high pressure (HP) hydro-desulphurised LCO, 180 or 221°C ICP to 350°C FCP). These potential movements allow the model to choose between networking and incurring transportation costs or reallocating diesel production from quality challenged towards favourably configured refinery types. In addition combined heavy atmospheric gas oils (HGO 350-370°C) and combined heavy cat gas oils (MCO 350-370°C) are allowed to move from simple and CC refineries as hydrocracker feed to the other refinery types that have HC. Vacuum gas oils are also allowed to move in case required to rebalance shifts of conversion between CC and HC.

The automotive gas oil reformulation studied is related to reduction of sulphur content and increasing cetane number.

The main mechanism for diesel sulphur reduction is direct desulphurisation. Additional mechanisms to cover a shortfall of diesel is via hydrocracking, ranging from gofining/mild HCU (FCC feed desulphurisation with associated conversion) to recycle hydrocracking (full conversion of the feed).

High cetane components are produced via aromatics saturation (hydro-dearomatising using 2nd Stage Hydrogenation) in combination with hydrocracking again also covering the shortfall of products. Increasing severity of reformulation sees an increased hydro-dearomatisation and a shift from CC utilisation to increasing HC.

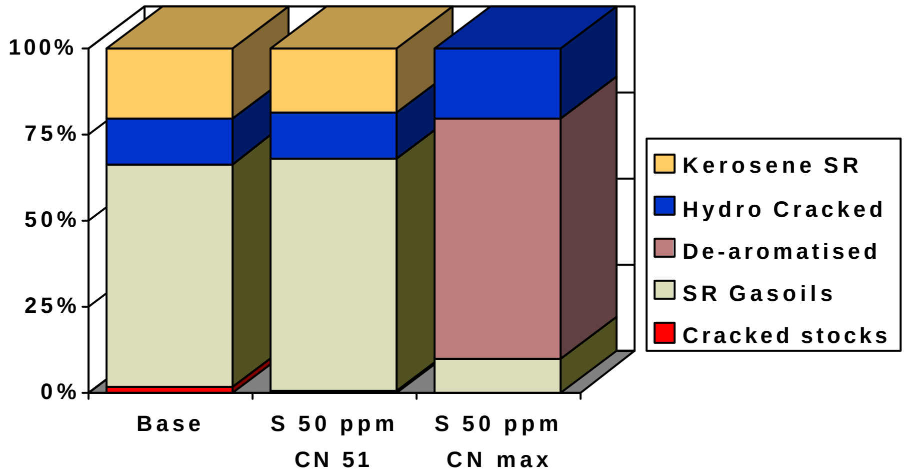
At the molecular level there are limits to what is feasible. Conversion of aromatic compounds into naphthenes improves cetane number, but does not raise the CN to that of paraffins. For many North Sea crudes such as Brent Blend, the maximum gas oil cetane number achievable is around the 55-56 mark, reflecting the relatively low paraffin content of these crudes. Many of the new North Sea crudes are of a more naphthenic nature than Brent Blend and the gas oils cannot be made to such high cetane specifications. Diesel blending for cold flow properties reduces the blended cetane by at least one point.

Another issue is the progressive reduction of endpoints in automotive gas oil. Reducing the endpoint reduces first of all availability and secondly reduces the attainable cetane level. At very high cetane levels the desulphurised straight run gas oil is virtually excluded from the diesel blend and the blend consists of hydrocracked and hydro-dearomatised straight-run gas oil components with some kerosine for cold flow correction. With increasing severity more and more components will become orphaned i.e. cannot be used in the product making some crudes totally unattractive for use in Europe. This will affect crude selection and trade flows.

Although not explicitly addressed in this study there is a problem with very low di+ aromatics using the definition as introduced in EPEFE/AO-1. The method applied is the IP-391 modified (including backflush). The IP-391 defines aromatics as mono-aromatics, di-aromatics and PAH i.e. compounds with 3 and higher number aromatic ring structures. For the purpose of the AO1 specifications, the method used defines poly-aromatics as di+ aromatics as measured via IP-391 modified.[2] The Swedish Class 1 gas oil uses a different specification i.e. (tri+ aromatic rings) PAH as determined by a method similar to the IP method.

An example of what happens to the diesel fuel blending pool of components is shown in ***Figure 4***.

Figure 4 Typical diesel component changes as sulphur reduces and CN increases.



The reduction of sulphur to 50 ppm requires no significant changes in the processing except for HDS, and the basic pool of components stays the same. However the case is very different for higher CN. Dearomatised and hydrocracked components become essential. The straight-run (SR) kerosine is also limited by its relatively low CN and is replaced with dearomatised kerosene. It can be seen that the blend pool has little remaining low CN components that can be processed or substituted by ones with the very high CN levels required to be useful. The remaining SR gas oil is insufficient when dearomatised to allow the next 1 CN higher level to be reached. Hence this 57 CN case represents the highest whole number CN specification feasible for the region concerned.

4.7. PROCESS UNIT INVESTMENT COSTS

The new process units listed in ***Table 7*** cover all of those that are required by reformulation, some of which change refinery types that otherwise become non-viable. The total costs incorporate all of the elements included in real life projects. These include all of the front-end costs of process selection, engineering and project management, all the on-plot facilities including catalysts and suchlike, the associated off-plot and other infrastructure investments required including amounts for all the associated facilities to ensure the project does not impair the chances of other future

[2] Given the limited accuracy of the current test method, the lowest realistic PAH specification is in the region of 2.5% to 3%.

investments. Associated costs also arise on surrounding units and other facilities to assure the highest safety and environmental standards are maintained for the overall site installation. Operations control, maintenance and other operating aspects of the installation need money to be spent up front, so that what is put in will be consistent with efficient low manpower and energy requirements that are fundamental requirements of future refineries in Europe. The costs have been generated by discussion with oil industry people with experience of actual projects in their companies. The costs are quoted in millions of US$ (M$, current money).

Table 7 Process unit project investment costs

	Internal				External			
	Typical capacity Mtpa	Min capacity Mtpa	Base cost M$	Scale	Typical capacity Mtpa	Min capacity Mtpa	Base cost M$	Scale
Unit Costs								
Distiller	10.000		100.0	Typical				
Vac Dist	4.000		50.0	Typical				
Visbreaker	0.840		35.0	Typical				
Reformer LP	0.876		95.0	Typical				
Reformer HP	0.876		80.0	Typical				
MCN Reforming	0.876	0.263	20.0	Individual				
Platformate splitter	0.650	0.195	5.0	Individual				
Hydrotreater	0.900		30.0	Typical				
Hydrodesulphuriser LP	1.300	0.390	50.0	Individual				
Hydrodesulphuriser MP	1.300	0.390	70.0	Individual				
Hydrodesuphuriser HP	1.300	0.390	75.0	Individual				
Bitumen Plant	1.000		50.0	Typical				
Lubes Plant	0.500		50.0	Typical				
Hydrogen Unit	0.200		50.0	Typical				
Delayed Coker	1.200		400.0	Typical				
Alkylation plant	0.182		50.0	Typical				
Tops Isom once through	0.219		20.0	Typical				
Tops isom recycle	0.219		35.0	Typical				
Light platformate isom	0.219	0.066	40.0	Individual				
MTBE plant	0.051		10.0	Typical	0.500		350.0	Typical
Butamer (Internal) ,Methanol (External)	0.219		35.0	Typical	0.500		400.0	Typical
Sulphur recovery	0.146	0.044	35.0	Individual				
Tame plant	0.2		25.0	Typical				
Residue desulphurisation	1.200		600.0	Typical				
HP LCO dearomatisation	1.300		120.0	Typical				
2nd stage hydrogentation	1.300	0.390	50.0	Individual				
HCN hydrotreater	0.900	0.270	50.0	Individual				
Cat cracker	1.569		225.0	Typical				
Hydro residue conversion	1.200		700.0	Typical				
Hydrocracker recycle	1.300		210.0	Typical				
Hydrocracker once through	1.300		150.0	Typical				
Gofiner	1.300		105.0	Typical				
LCCG Splitter	0.650	0.195	5.0	Individual				
LCCG Merox extraction	0.213	0.064	5.0	Individual				
Flue gas desulphuriser	0.414		230	Typical				

Published costs are often lower. For instance, the process licensers can quote costs significantly lower than the tabulated figures. Such companies tend not to experience all the cost elements by nature of their limited involvement in the overall procedure and their commercial interests tend to influence on the low side their cost quotations for scoping studies.

4.8. REFINERY INVESTMENT ALLOCATION LOGIC

The hierarchical approach using the 7-region model to set the base crude slates and inter regional movements of intermediates and products and using the seven region-specific 4-refinery models to calculate the new unit utilisation and inter refinery movements allows automation of the allocation of costs. This is done in an analysis model constructed using Lotus IMPROV, fed by the LP output loaded in batchwise for each of the seven regions. The equations used in this investment costs model are listed in ***Appendix 3.***

Incremental inter refinery-type gasoline and diesel component movements are charged to operating costs at 12 $/t. Each refinery exporting components is assumed to require modifications to off-site facilities costing M$1. Each importing refinery requires M$5 for facilities and inventory.

The required new process units are categorised into two base types. Firstly there are the major infrastructure units, e.g. new crude units, hydrocrackers, gofiners, cat crackers. These are allocated automatically by equations based on a philosophy of shared typical-sized units as per ***Table 7***. The number of units is calculated as the required capacity of each plant type by refinery divided by the size of a typical unit. Secondly there are new units not amenable to sharing such as cat gasoline splitters, cat gasoline processors, alkylate plants, isomerisation units, gas oil hydrodesulphurisation and dearomatisation units, etc. These are allocated one per refinery with sizes averaged to give individual unit sizes, subject to minimum size criteria. Costs are attached to the numbers of new units according to the unit cost table, and where necessary scaled according to size using the exponent 0.6 of the individual : typical size ratio to compensate for the loss of economy of scale when building smaller-sized units.

In calculating the required capacity of new gas oil hydrodesulphurisation units, it is necessary to take into account that the LP model does not adequately model that it will be necessary to remove sulphur from kerosine when diesel sulphur specifications are set at ultra-low levels. The tonnes of kerosine requiring HDS are back calculated from the hydrotreater (HT unit) utilisations, net of the throughput changes required for reformer feed preparation. The new kerosine HDS units that are required are assumed built in typical sizes with the investment/size parameters as for naphtha/kerosine HT.

The existing and AO1-required medium pressure (MP) and high pressure (HP) HDS units are modelled as MPHDS units with lower levels of desulphurisation (93%) than state of the art desulphurisation potential with new HPHDS (99.5%). A CONCAWE survey of HDS installations was carried out to identify the MPHDS units having potential to be upgraded to new HPHDS standards. Some 20 units are indicated as having upgrade potential at revamp cost about half that of new units (M$40, say). In the results, new grassroots HPHDS investment costs are applied (M$75). Thus if all the potential revamps are realised, the study diesel sulphur costs would be overstated by some 0.6 GEUR NPV at the 50 ppm specification level.

The HDS revamps are not taken account of in the economic evaluation as there are considered to be upside risks on the costs that are at least as big. The study assumes no change to the number of units in each refinery and no erosion of the spare capacity and component routing flexibility that enables refineries today to maintain high utilisations in the region of 93% or more of nameplate capacity. HDS downtime for maintenance, modification, catalyst change or hydrogen shortage due to reformer/H_2 plant downtime is compensated for today by running neat low sulphur crudes which can meet today's specifications and by blending unusable components into the non-road fuel gas oil products. These alternatives will not be available in the future if there are very tight diesel sulphur specifications, very high diesel demands requiring the conserving of all suitable components and low non-road fuel gas oil demands fully met by components unsuitable for diesel fuel. Instead, the overall service factor of the refineries will be impaired. With no free spare refineries in the long-term, every 1% loss in the refinery serviceability would cost roughly 1 GEUR to provide replacement refinery nameplate capacity. The anticipated loss of serviceability with 50 ppm sulphur diesel is in the region of one percent. Thus the cost results in this study are not biased on the conservative side.

The analysis model is designed to monitor the hydrogen balances of each type of refinery. Where refineries have lower than achievable recoveries of hydrogen in fuel gas, it is assumed that the first additional tranche of hydrogen requirement can be made available by investment in H_2 recovery facilities and upgrading to usable levels of concentration and pressure. This requires investment of M$0.5 per tonne H_2 per day. Further H_2 requirements are met from new H_2 plants at investment cost of M$1.0 per tonne H_2 per day.

5. RESULTS

5.1. QUALITY CONTROL COSTS.

The investment costs are made up of internal (to the EU refining industry) new plant investment costs, external new plant investments (worldscale MTBE and methanol plants) plus the offsite and hydrogen investments. These are calculated in M$ for each refinery type in each region on a delta basis, versus the AO1 base case (called 09y0), see ***Table 3*** and ***Appendix 4***.

The annual operating costs of the investments are calculated on the basis of:

- Maintenance 3% of investment cost.
- Operating labour 20% of maintenance cost.
- Operating overheads 20% of maintenance + operating labour costs.

Operating fuel consumption costs are calculated from the refinery consumption of KW crude oil, the field butanes feed consumption of external MTBE plants and the natural gas feed consumption of external methanol plants, (see ***Section 5.2***). Fuel consumption is costed in M$/year at an energy cost of 150$/toe (tonnes oil equivalent).

The quality control costs are presented in terms of net present value (NPV) using money units millions of Euros (1MEUR = M$1.1), see **Appendix 5**. NPV is calculated from the investment costs, operating costs and fuel costs using a factor of 9.75 to convert the annual operating and fuel costs to present value cost. The factor is based on a project life of 15 years and a discount factor of 7% p.a. on the future value of money.

Inspection of the cost results demonstrates the justification for using NPVs, which take account of both the up-front costs of investments and the ongoing costs of operation and fuel consumption and transportation. The investment cost element can range between 40% and 70% of the NPV, so investment costs alone do not adequately describe the cost effect.

In the following discussion of the cost results, the NPV figures in the text are rounded where possible to the nearest billion EUR in the interests of clarity and to avoid the appearance of unjustified accuracy. However, when making cost-effectiveness comparisons it is recommended that the actual figures tabulated in ***Appendix 5*** are used to ensure that differences are not inadvertently distorted.

5.1.1. Gasoline NPV

The costs of reducing sulphur from 150 ppm mass, 100 ppm and 50 ppm have been determined without and with aromatics reductions from 42% vol. to 35% vol. The cases run allow the splitting of costs between the sulphur and the aromatics elements.

As indicated in ***Table 3***, some gasoline packages were investigated with simultaneous diesel reformulation. This allows the calculation of synergy and antagonism between proposals for the two fuels. The results are shown in ***Section 5.1.3***.

As shown in ***Figure 5***, the NPV costs rise from 0.9 GEUR at 100 ppm to 3.5 GEUR at 50 ppm.

Gasoline sulphur above 50 ppm is only usually produced in refineries with cat cracker components or that take sulphurous return streams from petrochemicals plants. Non cat cracking refineries will tend to capitalise on their advantage by buying in sulphurous components at depressed prices, tending to even up the sulphur content of gasolines from the different refinery types. If sulphur specifications are set lower, when the cat cracking refinery has invested to solve its problems the supply of distressed components will tend to dry up, opening up the variability of sulphur levels within the bound set by the new specification.

The order in which the sulphur reduction processes are generally chosen tends to be: MCG reforming; HCG hydrotreating and LCG extractive caustic treatment. The chemicals return streams need to be desulphurised earlier on in the order when they comprise a larger proportion of the blend pool. Some gofining appears at the lower sulphur levels particularly when MCG reforming is limited by tightened aromatics specifications. Other processes need additions, to rebalance the unwanted side effects of the sulphur control mechanisms.

Figure 5 Gasoline sulphur reduction costs

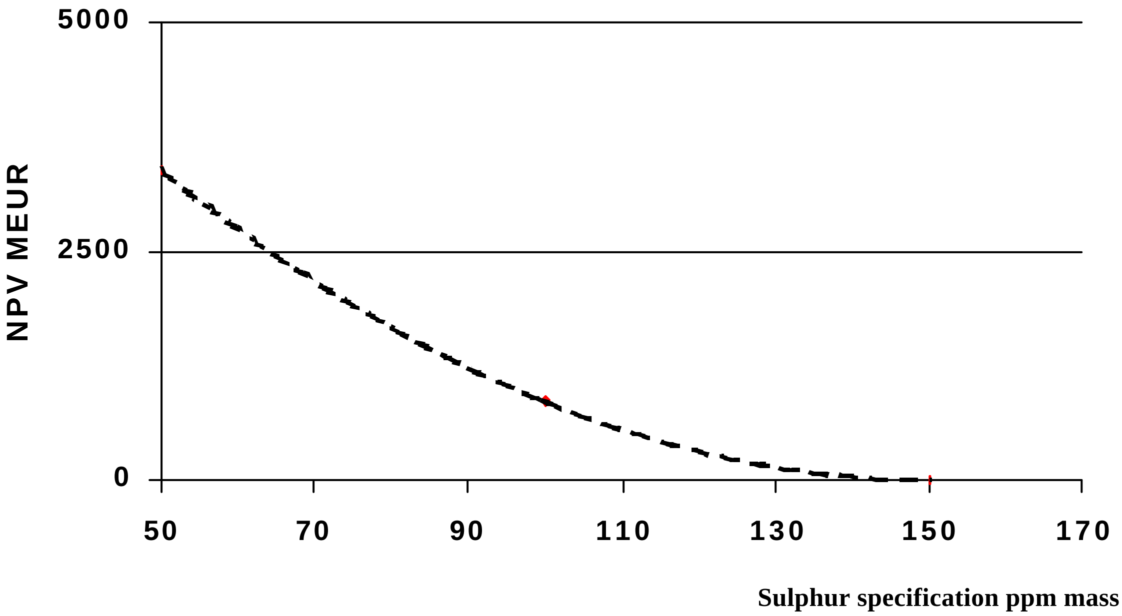
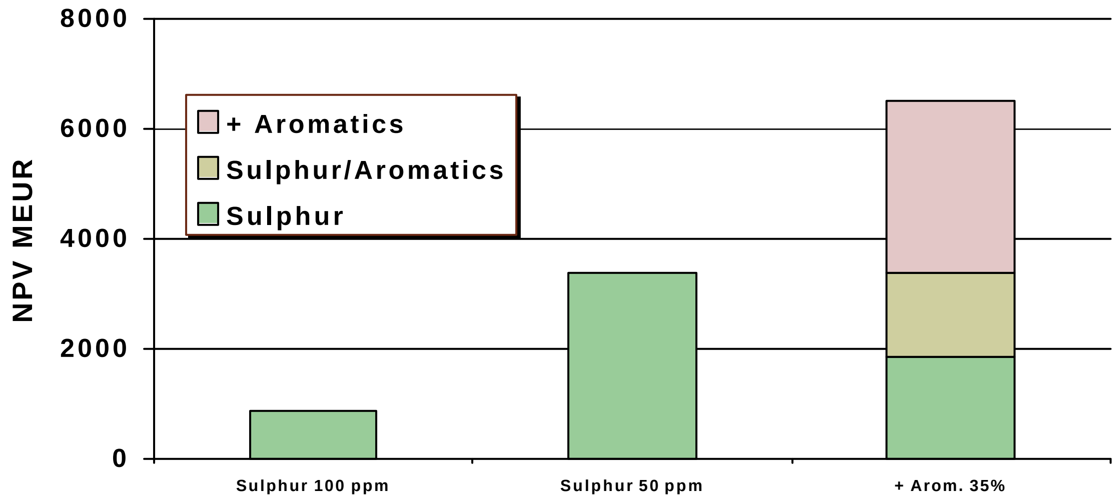


Figure 6 Gasoline sulphur and aromatics constraints costs



The average aromatics resulting from the base case specification of 42% vol. is calculated to be 37.8% because the many refineries with cat crackers that make some 80% of the gasoline, produce well below the base case specification. As shown in ***Figure 6***, constraining only aromatics to 35% costs 4.5 GEUR NPV. If sulphur is constrained first, the change to 35% aromatics costs 3 GEUR NPV indicating the level of cost synergy between aromatics and sulphur reductions. Although some refineries with CC already meet 35% aromatics, none of relatively few simple and HC refineries can do this and they rely on component transfers from refineries with CC.

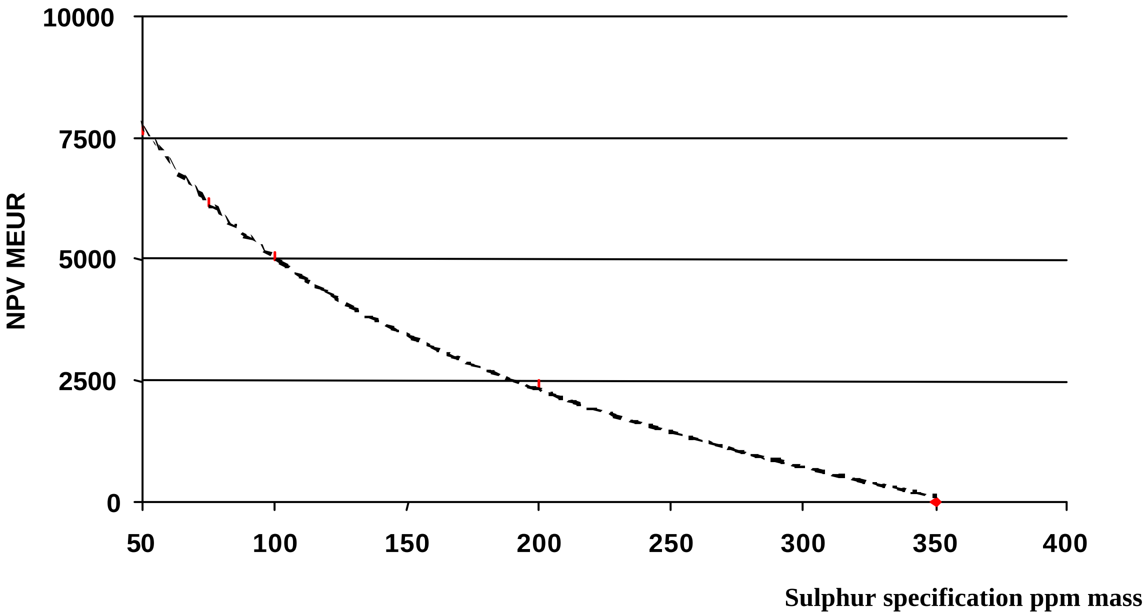
The initial aromatics control option used is the movement of aromatics free components from cat cracking refineries where gasoline is below 42% aromatics, to simple and HC refineries whose gasoline from own components is naturally above 42%. This requires investment in tankage, other offsite facilities and inventory and incurs freight costs. The reliance of the simple and the HC refineries on the others becomes more acute as aromatics are lowered. In general commercial price mechanisms are likely to be established that enable the trading of components. However, in certain cases the component rich refinery may be unprepared to share its advantage with a reliant refinery. The choices then open to the reliant refinery would be either to invest in its own uneconomic small cat cracker or to shut down or sell out, resulting in further consolidation of the European refining industry in the major centres. The vulnerable refineries tend to be in locations where even the relatively small number of direct jobs and the several times greater number of associated jobs lost would be keenly felt by the communities affected.

Aromatics are reduced firstly by increasing isomerisation at the expense of reforming. It should be noted that as a consequence the petrochemicals feedstocks change from predominantly light to medium virgin naphthas. No debit has been added because CONCAWE is not in a position to model chemicals production. Further follow up with chemicals companies is necessary if aromatics reduction below 35% becomes a serious proposition. The loss of hydrogen from the reformers has to be replaced by investment in hydrogen recovery/production facilities.

5.1.2. Diesel NPV

The base case for diesel uses the qualities specified in the Council Common Position of October 1997. The costs of reducing sulphur from 350 ppm mass to 200, 100, 75 and 50 ppm have been determined for a cetane number at 51 without and with gasoline reformulation. The main mechanism applied is direct desulphurisation, progressively including desulphurisation of the kerosine fraction blended into the final diesel blend. The other mechanism coming into play is the use of hydrocracking for volume control as well as freeing up components for diesel blending. As shown in ***Figure 7***, the NPV costs rise from 2.5 GEUR at 200 ppm to 8 GEUR at 50 ppm reflecting the progressively more severe treating required, building additional HDS capacity as well as the associated increasing hydrogen use.

Figure 7 Costs of diesel sulphur reduction

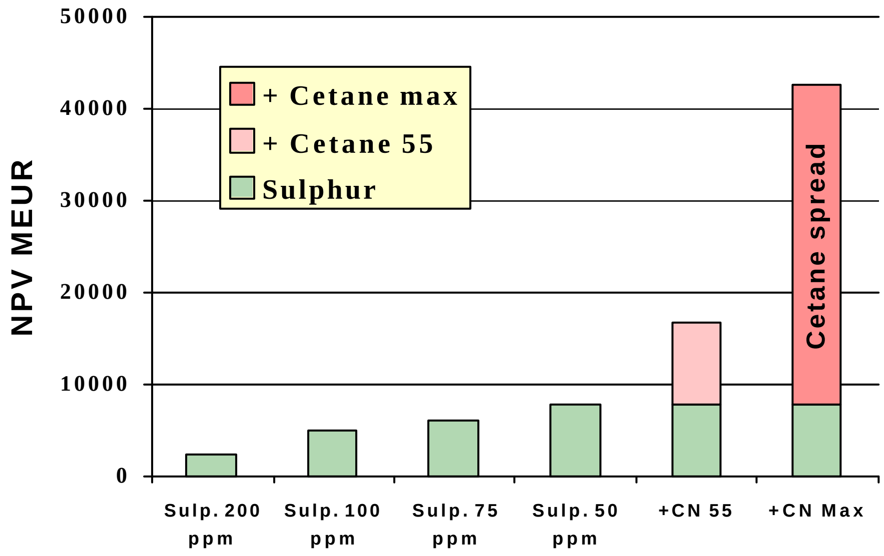


In addition to reducing sulphur the effect of increasing cetane number specification was studied. In ***Figure 8*** the NPV is given for the sulphur reduction and for increasing cetane number. It is quite clear that cetane increase is more costly than sulphur reduction. The mechanisms applied are removing the (already small-due to density etc.) volume of cat cracked gas oil from the diesel blend and converting desulphurised straight run kerosenes and gas oil by dearomatising and through the use of hydrocracking. As indicated before, the achievable cetane levels from total aromatics removal are 56-60 for straight run gas oil (before kerosine blending) and some 51 to 60 for hydrocracked gas oil depending on the severity level. When using once-through (mild severity) HCU the achievable level is around 51 cetane.

There would be some synergy with reducing sulphur in both gas oil and gasoline since the cat cracker feed is desulphurised as part of the gofiner/once through HC process. A common aspect of the two processes is the substantial hydrogen usage, which brings the requirement for construction of hydrogen manufacturing facilities and associated use of gas for hydrogen production.

As shown in ***Figure 8***, the additional cost for 55 CN specification over the 50 ppm sulphur specification case is 9 GEUR NPV.

Figure 8 Costs of increasing diesel cetane number



Cetane levels approaching 58 CN are not feasible due to the fact that the regional volume balance cannot be maintained. The conflicting demands posed by high cetane diesel (high cetane components and hydrogen use) and low aromatics gasoline (limiting the substitution of CC by HC) cannot readily be reconciled.

The two aspects mainly limiting the flexibility to increase cetane are the ratio of heating oil to diesel and the winter quality of the diesel. The cold properties of the winter grades in Scandinavia severely restrict the achievable average cetane level that can be attained. In the absence of a direct processing route to very high cetane components it is not certain that the high cetane is achievable even with these estimated high investments and NPV.

In addition increased costs for adjustments of side effects will result due to the increased use of additives

Depending on the cetane level increased use of cetane improver can be assumed. Based on current 2-EHN (2-Ethyl Hexyl-Nitrate) additive costs of some 1150 USD/T, the CN improver costs are estimated in the range of 0.35 - 0.4 USD per tonne diesel fuel per point cetane. Annual costs could be up to 150 MUSD/annum per three units of cetane, incurred to conform with the 51 CN specification.

Since the introduction of low sulphur diesel fuel in October 1996 lubricity additivation is being used in several areas of the EU to provide adequate lubricity performance. CEN is currently revising the EN 590 specification which will include a specification for lubricity performance for Diesel fuel. As a consequence, additional doping facilities in refineries may be required. It can be assumed that the consumption of lubricity additives in EU refineries would increase substantially with an introduction of very low sulphur Diesel fuels with a resulting increase in costs.

When lowering T90/T95 and PAH the amount of middle distillate flow improver (MDFI) additive used would increase with the expected decrease of additive response due to less heavier back-end in the gasoil. With a severe reduction of the sulphur level in diesel fuel the amount of conductivity improver used in EU refineries would increase as well.

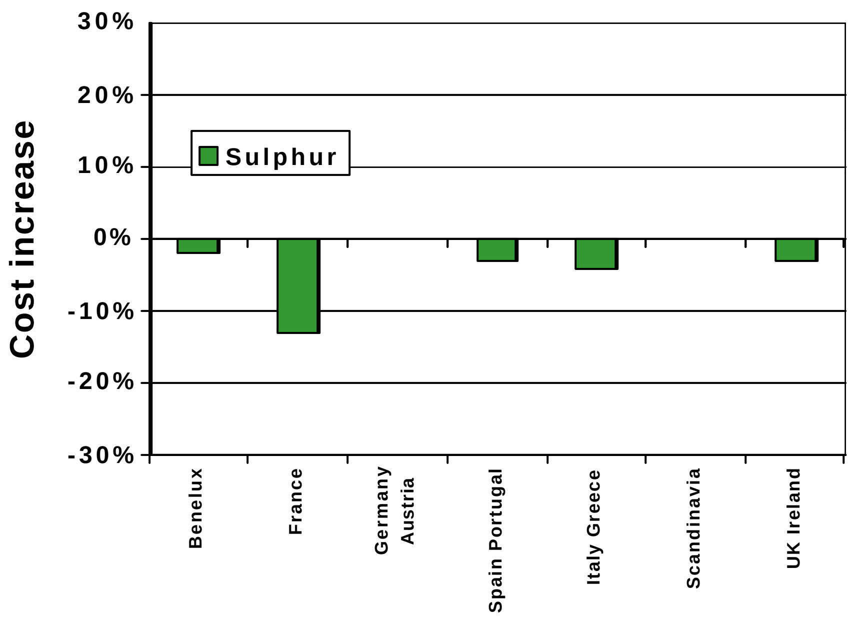
5.1.3. Synergy and antagonism between properties of gasoline and diesel

Synergy between changes in two different characteristics of the same fuel or between changes in the two fuels is deemed to exist if the NPV of the case in which the changes are taken together is less than the sum of the NPVs of the cases with the changes taken individually. If the NPV of the changes taken together are greater than the sum of the individual change cases, this is deemed to show antagonism.

Analysis of the NPV results tabulated in ***Appendix 5*** indicates that there is cost synergy between gasoline sulphur and aromatics amounting to 1.5 to 2 GEUR NPV. Desulphurisation increases hydrogen consumption and decreases octane. The processes used to rebalance the octane loss are different when aromatics are limited and when not limited. Internal refinery processes having synergistic tendencies include increasing reformate production which also increases hydrogen production and additional alkylation which also reduces aromatics. From outside the refineries imported MTBE is a control mechanism for both sulphur and aromatics.

Figure 9 shows that there is synergy between the 50 ppm sulphur cases in gasoline and in diesel in five out of the seven regions. The synergy occurs when a re-balancing mechanism for one property also happens to have a favourable effect on the other property at issue. An example is gofining. Primarily usable for reducing sulphur in gasoline, gofining also reduces the sulphur content of LCO. This might mean that available LP and MP HDS capacity could handle more of the IGO desulphurisation burden, thus reducing overall the amount of new HP HDS to meet the diesel sulphur. Other mechanisms, which tend to be used more in the cases studied, are more difficult to appraise for synergy.

Figure 9 Synergy between reductions to 50 ppm sulphur in gasoline and diesel



The result from the comparisons for sulphur in gasoline and in diesel is that although synergy exists, it is neither universally present, nor is it very large amounting to less than 5% NPV saving at the 50 ppm levels in both fuels. The limited synergy found tends to support the validity of using NPV data from the property changes taken individually in the cost-benefit analysis process.

Antagonism between lower gasoline aromatics and higher diesel CN is expected due to:

1) the tendency to increase CC throughputs producing light cat gasolines to substitute heavy cat gasolines and reformates thus also producing additional low CN cat components to be accommodated in the gas oil pool.

2) the tendency to increase HC throughputs producing high CN components for diesel, which brings along C6+ HC naphthas that require reforming to be usable as gasoline components resulting in them being highly aromatic.

The need for higher CC throughputs is hardly evident at the level of 35% aromatics in gasoline and there is also apparently room to accommodate the gasoline effects of the higher HC throughputs in the highest CN cases by using the non-antagonistic mechanisms of isomerisation and import MTBE. However, when such mechanisms are fully utilised at some lower level of aromatics specification, the antagonism is expected to be severe due to the wide margins between the aromatics level of HC reformate and finished gasoline and the CN of cat gas oils and finished diesel, respectively.

Such antagonism found, taking into account the other evidence of the non-viable nature of the process mechanisms coming in at the extreme (e.g. CN), warns that combined severe cases approach viability boundaries. The NPV may very seriously understate the difficulty refineries face to establish viable operations under extreme conditions. The more extreme the requirements called for by legislation, the higher the risks become that strategies put in place by individual refineries may prove seriously insufficient overall, at least initially. Such unintended consequences could seriously undermine the implementation of such extreme measures and road transportation reliability, disrupting a vital sector where good order is essential to sustain the general economic growth of the EU.

If extremely severe measures are added on top of the existing, comprehensive and well proven sets of fuels specifications, the degrees of freedom to select components tend to disappear. Also some viable combinations of components which meet the new severe requirements may pose engine performance problems. When the technically achievable limits are reached, the simultaneous availability of the necessary quantity of every component becomes essential to continue production. Thus either supply reliability will decrease or additional refinery capacity will need to be built. If adequate sized refineries suited to such conditions are to come about, there will be additional costs that need to be passed on to the market.

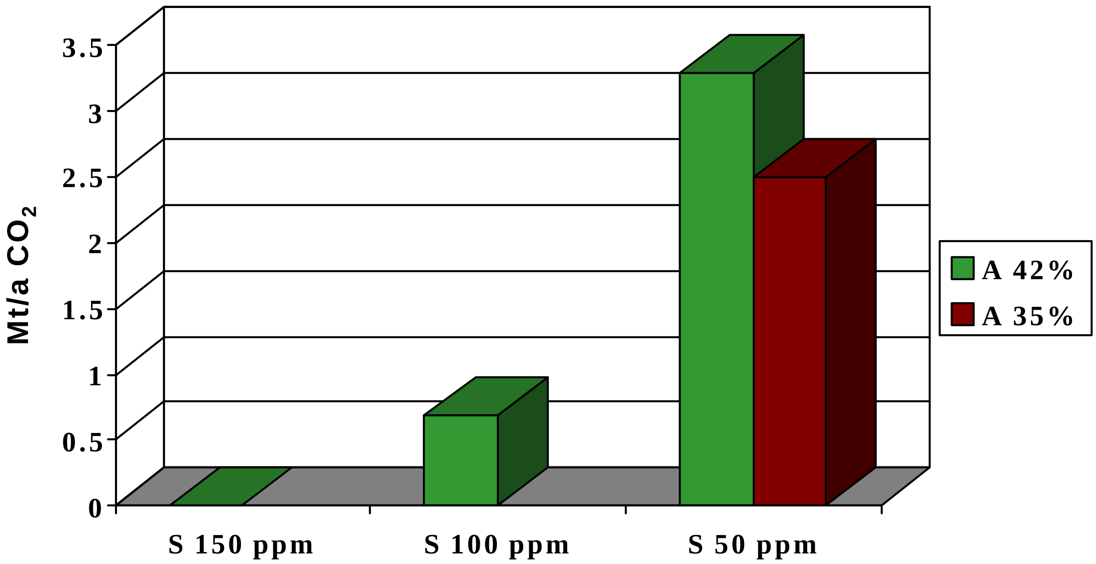
5.2. CO_2 EMISSIONS EFFECT

The CO_2 emissions effects are calculated by reference to the change in crude (KW) input to the refineries. Other factors are the inputs of feed field butanes for external MTBE plants and the natural gas fuel consumed, and the natural gas used as feedstock and fuel for the methanol plants that provide the co-feedstock to the external and the internal refinery MTBE plants. The results show the global emissions covering the changes from refineries and the external feed and component suppliers and from use of the fuels. As an example, for reduced aromatics in gasoline the emissions include the net effect of the decrease due to the lower carbon to hydrogen ratio and of any increase due to higher oxygen content.

5.2.1. Gasoline CO_2 emissions implications

As illustrated by ***Figure 10*** the CO_2 emissions effects of the gasoline measures would be relatively small, for example approaching 3.5 Mt/a of additional CO_2 to achieve 50 ppm sulphur. Paradoxically, the CO_2 emissions appear to decrease somewhat as aromatics get progressively constrained. This is because the imported MTBE mechanism modelled, which in effect makes gasoline from LPGs and natural gas instead of from crude oil, is relatively efficient from a carbon point of view.

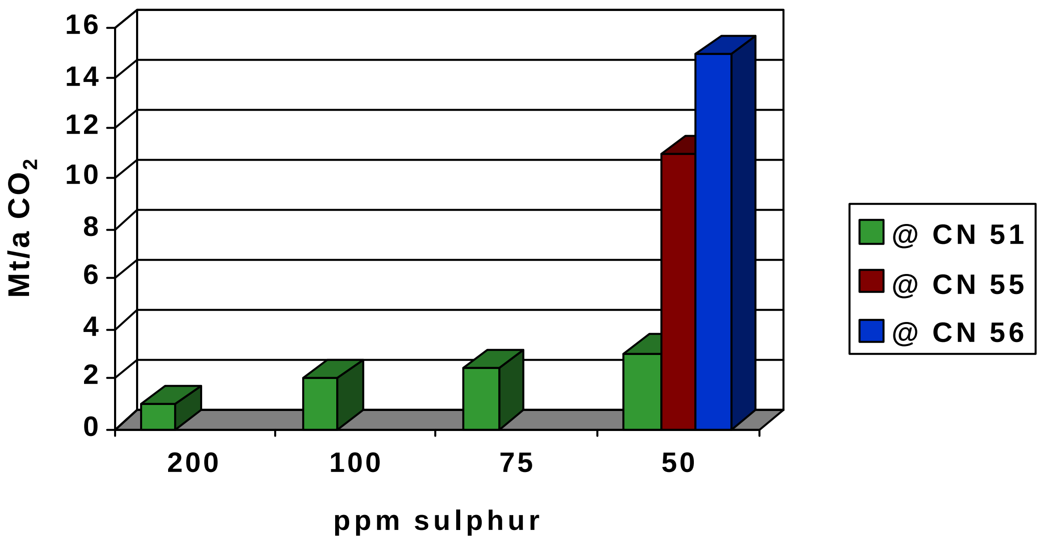
Figure 10 CO_2 emissions effects of gasoline measures



5.2.2. Diesel CO_2 emissions implications

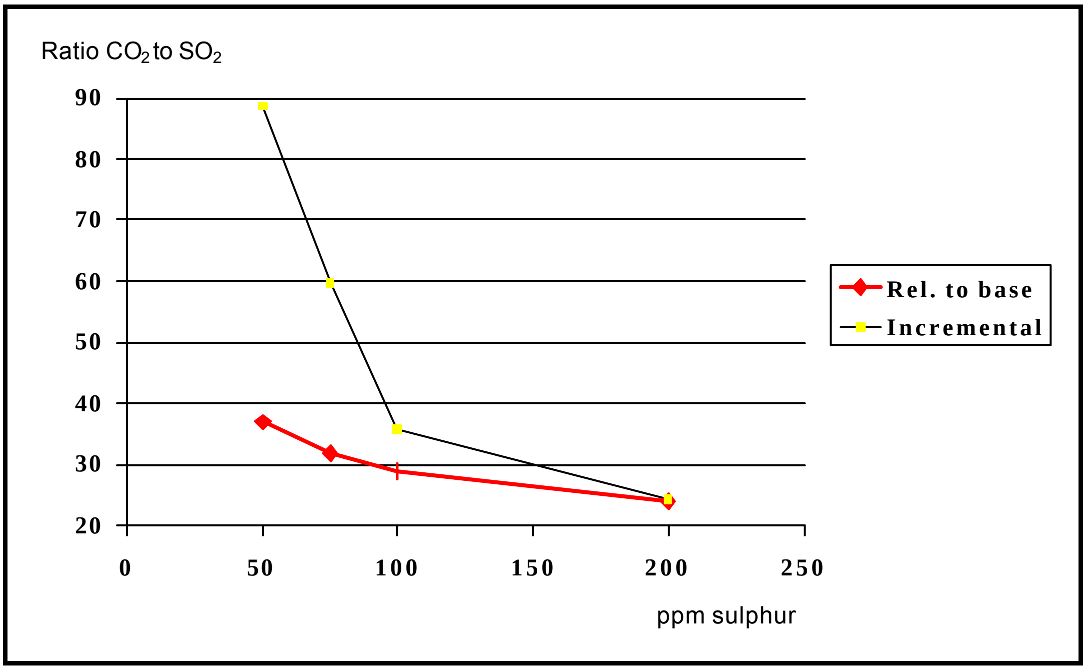
Figure 11 shows that the CO_2 emissions effects of diesel sulphur reductions are also quite small, being comparable with the gasoline effects. Cetane number is different as it brings in the need to manufacture hydrogen resulting in the rejection of carbon. As limiting CN is approached, cetane related CO_2 emissions increase dramatically from 8 Mt/a at 55 CN to 12 Mt/a at 56 CN, increases on top of 3 Mt/a for reducing sulphur to 50 ppm.

Figure 11 CO_2 emissions effects of diesel measures - Sulphur and Cetane Number



Another factor is the trade-off between the decrease in SO_2 emissions and the increase in CO_2 emissions required to bring them about. ***Figure 12*** shows that taking sulphur out of diesel requires between 25 and 37 times more CO_2 emissions than the SO_2 emissions saved relative to the base case at 350 ppm sulphur. On an incremental basis, i.e. compared to the previous level, the ratio CO_2 to SO_2 increases to 88 at 50 ppm sulphur.

Figure 12 CO_2 versus SO_2 emissions trade-off



APPENDIX 1 7-REGION SUPPLY/DEMAND BALANCES AS BASIS FOR INPUT INTO REGIONAL MODELS (YEAR 2010)

EU-15	*Manufac-tured*				*Import/export*				*Total System*
		Scandi-navia	*UK & Ireland*	*Benelux*	*Germany & Austria*	*France*	*Spain & Portugal*	*Italy & Greece*	
Crude Purchase									
Brent Blend	182.6								182.6
Iranian light	121.5								121.5
Kuwait	202.9								202.9
Nigerian Forcados	91.1								91.1
Algerian cond.	10.0								10.0
Total	**607.9**		**.**	**.**	**.**	**.**	**.**	**.**	**607.9**
Other Purchases									
MTBE	4.5								4.5
Chemical return	9.0								9.0
BTX return	2.2								2.2
Gas oil blend comp	15.0								15.0
Methanol	0.7								0.7
Natural gas	3.1								3.1
Total	**34.5**		**.**	**.**	**.**	**.**	**.**	**.**	**34.5**
Transfers									
GFU Waxy HCD	1.6								1.6
Blending Mtpa									
Refinery Gas	1.2								1.2
LPG	18.3	-0.3	-0.1			0.1	0.3		18.3
Chemical feed	28.5			-0.4	5.1	.3	-0.3	-4.7	28.5
Gasoline Export 93	5.0			-5.0					0.0
Gasoline Bio 94.5	17.0				1.8			-1.8	17.0
Gasoline UL 95H	57.1	1.6	2.9	-1.6		-0.5	-2.4		57.1
Gasoline UL 95L	53.2								53.2
BTX feed	6.8								6.8
Avtur & kerosine	49.9		3.2		3.7	-1.1	-2.1	-3.7	49.9
Auto diesel city	2.0								2.0
Auto diesel north	8.1				1.1			-1.1	8.1
Auto diesel mid	91.0	-3.1		-6.5	6.5	9.1		-6.0	91.0
Auto diesel south	54.0		-2.9					2.9	54.0
Ind. Gas oil north	9.7								**9.7**
Ind. Gas oil mid	31.6					**3.8**		**-3.8**	**31.6**
Ind. Gas oil mid Ger	29.4			**-2.0**	**2.0**				**29.4**
Ind. Gas oil south	9.3								**9.3**
Fuel oil 0.6%	4.5								**4.5**
Fuel Oil 1%	27.4								**27.4**
Fuel Oil 2%	7.4								**7.4**
Fuel Oil 2.5%	12.5					**-4.1**		**4.1**	**12.5**
Bunker	29.2								**29.2**
Lube oil	6.9	**0.3**	**-0.3**	**-0.2**	**0.5**	**-0.3**			**6.9**
Low S coke	1.9								**1.9**
High S coke	1.1								**1.1**
Sulphur	4.4								**4.4**
Heavy residue	3.0								**3.0**
Bitumen	16.8		**-0.6**			**0.4**	**-0.1**	**0.3**	**16.8**
GFU Waxy HCD	1.6			-1.6					**0.0**
Total	**588.9**	**-1.5**	**2.2**	**-15.7**	**20.7**	**7.7**	**-4.6**	**-13.9**	**587.2**

					Import/export				
Scandinavia	***Manufac-tured***	***Scandi-navia***	***UK & Ireland***	***Benelux***	***Germany & Austria***	***France***	***Spain & Portugal***	***Italy & Greece***	***Total System***
Crude Purchase									
Brent Blend	5.5								5.5
Iranian light	5.7								5.7
Kuwait	7.9								7.9
Nigerian Forcados	18.7								18.7
Algerian condensate	0.3								0.3
Total	**38.0**	.	.	.	.	.	.	.	**38.0**
Other Purchases									
Mtbe	0.5								0.5
Chemical return	0.2								0.2
BTX return	0.1								0.1
Gas oil blending comp	2.6								2.6
Methanol	0.0								0.0
Natural gas	0.7								0.7
Total	**4.2**	.	.	.	.	.	.	.	**4.2**
Blending Mtpa									
LPG	0.5						-0.3		0.2
Chemical feed	0.7								0.7
Gasoline UL 95H	8.4			1.6					10.0
Avtur & kerosine	2.7								2.7
Auto diesel city	2.0								2.0
Auto diesel north	5.0								5.0
Auto diesel mid	3.1					-3.1			0.0
Ind. gas oil north	8.1								8.1
Fuel oil 0.6%	3.3								3.3
Fuel Oil 1%	2.9								2.9
Bunker	0.5								0.5
Lubes	0.1		0.3						0.4
Sulphur	0.2								0.2
Bitumen	1.4								1.4
Total	**39.0**	.	**0.3**	**1.6**	.	**-3.1**	**-0.3**	.	**37.4**

					Import/export				
UK & Ireland	***Manufac-tured***	***Scandi-navia***	***UK & Ireland***	***Benelux***	***Germany & Austria***	***France***	***Spain & Portugal***	***Italy & Greece***	***Total System***
Crude Purchase									
Brent Blend	47.1								47.1
Iranian light	13.0								13.0
Kuwait	20.1								20.1
Nigerian Forcados	8.4								8.4
Algerian condensate	3.2								3.2
Total	91.9	.	.	.	.	.	.	.	91.9
Other Purchases									
Mtbe	0.7								0.7
Chemical return	0.3								0.3
BTX return	0.3								0.3
Gasoil blending comp	0.6								0.6
Methanol	0.1								0.1
Natural gas									-
Total	2.1	.	.	.	.	.	.	.	2.1
Transfers									
GFU Waxy HCD				1.6					1.6
Blending Mtpa									
Refinery Gas	0.1								0.1
LPG	1.4					-0.1			1.3
Chemical feed	1.1								1.1
Gasoline UL 95H	26.9					0.5	2.4		29.8
BTX feed	1.0								1.0
Avtur & kerosine	12.6					1.1	2.1		15.8
Auto diesel mid	19.6								19.6
Auto diesel south	2.9							-2.9	0.0
Ind. gas oil mid	5.0								5.0
Fuel oil 0.6%	0.4								0.4
Fuel Oil 1%	5.6								5.6
Fuel Oil 2%	2.0								2.0
Fuel Oil 2.5%	0.9								0.9
Bunker	1.7								1.7
Lubes	1.9	-0.3							1.6
Low S coke	0.7								0.7
Sulphur7	0.5								0.5
Bitumen	3.0							-0.6	2.4
Total	87.2	-0.3	.	.	.	1.6	4.5	-3.5	89.5

Benelux	*Manufac-tured*	*Import/export*							*Total System*
		Scandi-navia	*UK & Ireland*	*Benelux*	*Germany & Austria*	*France*	*Spain & Portugal*	*Italy & Greece*	
Crude Purchase									
Brent Blend	8.7								8.7
Iranian light	9.7								9.7
Kuwait	54.9								54.9
Nigerian Forcados	9.4								9.4
Total	82.7	.	.	.	.	.	.	.	82.7
Other Purchases									
Mtbe	0.4								0.4
Chemical return	1.5								1.5
BTX return	0.3								0.3
Methanol	0.1								0.1
Total	2.2	.	.	.	.	.	.	.	2.2
Transfers									
GFU Waxy HCD			-1.6						-1.6
Blending Mtpa									
Refinery Gas	0.1								0.1
LPG	1.8								1.8
Chemical feed	3.8				-0.4				3.4
Reg Mog Exp 93	5.0								5.0
Gasoline UL 95H	1.6	-1.6							0.0
Gasoline UL 95L	9.2								9.2
BTX feed	1.0								1.0
Avtur & kerosine	5.3								5.3
Ind. gas oil mid Germany	1.9				-2.0				0.0
Auto diesel mid	16.8				-6.5				10.3
Ind. gas oil mid	10.7								10.7
Fuel oil 0.6%	0.6								0.6
Fuel Oil 1%	1.0								1.0
Bunker	14.5								14.5
Lubes	0.6				-0.2				0.4
Sulphur	0.9								0.9
Bitumen	0.9								0.9
Total	75.8	-1.6	.	.	-9.1	.	.	.	65.1

Germany & Austria	Manufac-tured	Import/export Scandi-navia	UK & Irelanc	Benelux	Germany & Austria	France	Spain & Portugal	Italy & Greece	Total System
Crude Purchase									
Brent Blend	39.3								39.3
Iranian light	13.0								13.0
Kuwait	34.4								34.4
Nigerian Forcados	19.2								19.2
Algerian condensate	4.5								4.5
Total	110.3	.	.	.	.	.	.	.	110.3
Other Purchases									
Mtbe	0.9								0.9
Chemical return	3.9								3.9
BTX return	0.6								0.6
Gasoil blending comp	5.8								5.8
Methanol	0.2								0.2
Total	11.4	.	.	.	.	.	.	.	11.4
Blending Mtpa									
Refinery Gas	0.7								0.7
LPG	4.1								4.1
Chemical feed	7.9			0.4				4.7	13.0
Gasoline Bio 94.5	5.2							1.8	7.0
Gasoline UL 95H	17.3								17.3
Gasoline UL 95L	3.1								3.1
BTX feed	1.8								1.8
Avtur & kerosine	4.9							3.7	8.6
Auto diesel north	3.1								3.1
Ind. gas oil mid Germany	27.5			2.0					29.4
Auto diesel mid	21.2			6.5					27.7
Ind. gas oil north	0.5							1.1	1.6
Fuel Oil 1%	5.7								5.7
Bunker	1.7								1.7
Lubes	1.2			0.2		0.3			1.7
Low S coke	1.0								1.0
High S coke	0.1								0.1
Sulphur	0.9								0.9
Bitumen	3.5								3.5
Total	111.3	.	.	9.1	.	0.3	.	11.3	132.0

France	Manufac-tured	Scandi-navia	UK & Ireland	Benelux	Import/export Germany & Austria	France	Spain & Portugal	Italy & Greece	Total System
Crude Purchase									
Brent Blend	15.2								15.2
Iranian light	34.4								34.4
Kuwait	15.8								15.8
Nigerian Forcados	19.6								19.6
Algerian condensate	1.0								1.0
Total	85.9	.	.	.	.	.	.	.	85.9
Other Purchases									
Mtbe	0.5								0.5
Chemical return	1.3								1.3
BTX return	0.3								0.3
Gasoil blending comp	4.2								4.2
Methanol	0.1								0.1
Natural gas	0.1								0.1
Total	6.5	.	.	.	.	.	.	.	6.5
Blending Mtpa									
Refinery Gas	0.1								0.1
LPG	2.8		0.1						2.9
Chemical feed	4.0						0.3		4.3
Gasoline Bio 94.5	5.0								5.0
Gasoline UL 95H	0.5		-0.5						0.0
Gasoline UL 95L	11.2								11.2
BTX feed	1.0								1.0
Avtur & kerosine	7.0		-1.1						5.9
Auto diesel mid	24.3	3.1						6.0	33.4
Ind. gas oil mid	12.1							3.8	15.9
Fuel Oil 1%	1.8								1.8
Fuel Oil 2%	1.8								1.8
Fuel Oil 2.5%	5.9							-4.1	1.8
Bunker	2.1								2.1
Lubes	1.4				-0.3				1.1
Sulphur	0.5								0.5
Bitumen	3.0							0.4	3.4
Total	84.6	3.1	-1.6	.	-0.3	.	0.3	6.1	92.2

		Import/export							
Spain & Portugal	***Manufac-tured***	***Scandi-navia***	***UK & Ireland***	***Benelux***	***Germany & Austria***	***France***	***Spain & Portugal***	***Italy & Greece***	***Total System***
Crude Purchase									
Brent Blend	22.7								22.7
Iranian light	15.8								15.8
Kuwait	28.7								28.7
Nigerian Forcados	11.4								11.4
Algerian condensate	1.0								1.0
Total	79.7	.	.	.	.	.	.	.	79.7
Other Purchases									
Mtbe	0.7								0.7
Chemical return	1.0								1.0
BTX return	0.3								0.3
Gasoil blending comp	1.8								1.8
Methanol	0.1								0.1
Natural gas	1.3								1.3
Total	5.1	.	.	.	.	.	.	.	5.1
Blending Mtpa									
Refinery Gas	0.1								0.1
LPG	3.2	0.3							3.5
Chemical feed	3.6					-0.3			3.3
Gasoline Bio 94.5	2.0								2.0
Gasoline UL 95H	2.4		-2.4						0.0
Gasoline UL 95L	11.7								11.7
BTX feed	1.0								1.0
Avtur & kerosine	8.0		-2.1						5.9
Auto diesel south	24.0								24.0
Ind. gas oil south	5.3								5.3
Fuel Oil 1%	1.6								1.6
Fuel Oil 2%	3.6								3.6
Fuel Oil 2.5%	3.6								3.6
Bunker	3.6								3.6
Lubes	0.4								0.4
High S coke	0.5								0.5
Sulphur	0.5								0.5
Bitumen	2.7							-0.1	2.6
Total	77.8	0.3	-4.5	.	.	-0.3	.	-0.1	73.2

Italy & Greece	Manufac-tured	Import/export Scandi-navia	UK & Ireland	Benelux	Germany & Austria	France	Spain & Portugal	Italy & Greece	Total System
Crude Purchase									
Brent Blend	44.1								44.1
Iranian light	29.9								29.9
Kuwait	41.1								41.1
Nigerian Forcados	4.4								4.4
Total	119.4	.	.	.	.	.	.	.	119.4
Other Purchases									
Mtbe	0.8								0.8
Chemical return	0.8								0.8
BTX return	0.3								0.3
Methanol	0.1								0.1
Natural gas	1.0								1.0
Total	3.0	.	.	.	.	.	.	.	3.0
Blending Mtpa									
Refinery Gas	0.1								0.1
LPG	4.5								4.5
Chemical feed	7.4				-4.7				2.7
Gasoline Bio 94.5	4.8				-1.8				3.0
Gasoline UL 95L	18.0								18.0
BTX feed	1.0								1.0
Avtur & kerosine	9.4				-3.7				5.7
Auto diesel mid	6.0					-6.0			0.0
Auto diesel south	27.1		2.9						30.0
Ind. gas oil north	1.1				-1.1				0.0
Ind. gas oil mid	3.8					-3.8			0.0
Ind. gas oil south	4.0								4.0
Fuel oil 0.6%	0.2								0.2
Fuel Oil 1%	8.8								8.8
Fuel Oil 2.5%	2.1					4.1			6.2
Bunker	5.1								5.1
Lubes	1.3								1.3
Low S coke	0.2								0.2
High S coke	0.5								0.5
Sulphur	0.9								0.9
Heavy residue	3.0								3.0
Bitumen	2.3		0.6			-0.4	0.1		2.6
Total	111.6	.	3.5	.	-11.3	-6.1	0.1	.	97.8

APPENDIX 2 REGIONAL SUPPLY/DEMAND BALANCES (YEAR 2010)

EU-15

	Simple	FCC	HCU	FCC & HCU	Total System
Crude Purchase Mtpa					
Brent Blend	28.0	114.9	7.6	32.0	**182.5**
Iranian light	10.2	72.0	13.7	25.7	**121.5**
Kuwait	34.7	102.5	36.4	40.4	**213.9**
Nigerian Forcados	14.2	53.7	6.2	16.8	**91.0**
Algerian condensate	1.6	3.7	3.0	1.7	**10.0**
Total	**88.6**	**346.9**	**66.8**	**116.6**	**618.9**
Other Purchases Mtpa					
Mtbe	0.0	0.4	0.0	0.1	**0.5**
BTX return	0.6	0.0	1.2	0.4	**2.3**
Gas oil blending component	3.4	9.5	1.0	1.1	**15.0**
Methanol	0.0	0.6	0.0	0.2	**0.8**
Natural gas	0.1	1.5	0.2	1.3	**3.1**
Chemical return	0.6	5.8	0.8	1.8	**9.0**
Gofinate	0.0	1.6	0.0	0.0	**1.6**
Total	**4.7**	**19.4**	**3.3**	**5.0**	**32.4**
Blending Mtpa					
Refinery Gas	0.4	0.1	0.1	0.5	**1.1**
LPG	1.9	11.8	1.9	3.1	**18.6**
Chemical feed	3.6	16.1	3.2	5.7	**28.5**
Gasoline export	0.0	7.2	0.6	2.1	**10.0**
Gasoline	11.3	76.1	12.8	23.7	**124.0**
Inter-EU Gasoline export	0.0	1.9	0.3	2.5	**4.8**
BTX feed	1.8	1.9	1.4	1.7	**6.8**
Arctic ago/igo	0.4	0.1	0.0	1.5	**2.0**
Avtur & kerosene	7.0	30.4	3.8	8.7	**49.9**
Automotive diesel	22.3	79.5	18.2	33.1	**153.1**
Heating oil	2.5	28.3	3.1	6.7	**40.6**
Other gas oil	5.6	20.8	6.7	6.3	**39.4**
Fuel oil 0.6%	1.5	1.0	0.2	1.8	**4.5**
Fuel oil 1%	7.0	16.7	1.4	2.3	**27.4**
Fuel oil 2%	1.4	2.5	2.4	1.0	**7.4**
Fuel oil 3.0%	1.8	6.4	1.5	2.8	**12.5**
Bunker	1.4	16.0	4.9	6.9	**29.2**
Lubes	3.0	4.0	0.0	0.4	**7.4**
Low S coke	0.0	1.4	0.3	0.5	**2.1**
High S coke	0.7	1.1	0.1	0.2	**2.1**
Sulphur	0.4	2.4	0.7	1.0	**4.5**
Heavy residue	0.0	0.0	1.3	1.7	**3.0**
Bitumen	4.8	10.3	0.3	1.5	**16.9**
Gofinate	0.0	1.6	0.0	0.0	**1.6**
Total	**78.7**	**337.7**	**65.2**	**115.9**	**597.5**

SCANDINAVIA

	Simple	FCC	HCU	FCC & HCU	Total System
Crude Purchase Mtpa					
Brent Blend	3.4	0.4		1.7	**5.5**
Iranian light	3.7	0.2		1.8	**5.7**
Kuwait	3.0	0.7		5.3	**9.0**
Nigerian Forcados	8.1	0.8		9.8	**18.7**
Algerian condensate	0.2	0.0			**0.3**
Total	**18.4**	**2.0**	**0.0**	**18.6**	**39.0**
Other Purchases Mtpa					
BTX return				0.1	**0.1**
Gas oil blending component	1.8	**0.1**		0.7	**2.6**
Methanol		**0.0**		0.0	**0.0**
Natural gas	0.1			0.6	**0.7**
Chemical return				0.2	**0.2**
Total	**1.9**	**0.1**	**0.0**	**1.6**	**3.6**
Blending Mtpa					
LPG	0.3	0.2		0.1	**0.5**
Chemical feed	0.1			0.6	**0.7**
Gasoline unleaded 95	2.7	0.5		5.3	**8.5**
Arctic automotive diesel	0.4	0.1		1.5	**2.0**
Avtur & kerosine	1.9	0.1		0.6	**2.7**
Automotive diesel	3.7	0.4		4.0	**8.1**
Heating oil	1.8	0.1		2.2	**4.1**
Other gas oil	1.0	0.3		2.7	**4.1**
Fuel oil 0.6%	1.5	0.2		1.7	**3.3**
Fuel oil 1%	2.4	0.1		0.4	**2.9**
Bunker		0.0		0.5	**0.5**
Lubes	0.1				**0.1**
Sulphur	0.1	0.0		0.2	**0.3**
Bitumen	0.8			0.6	**1.4**
Total	**16.8**	**2.0**	**0.0**	**20.3**	**39.1**

UK and IRELAND

	Simple	FCC	HCU	FCC & HCU	Total System
Crude Purchase Mtpa					
Brent Blend	2.6	40.2	0.3	4.1	**47.1**
Iranian light		10.2	0.9	2.0	**13.0**
Kuwait	6.0	15.5	1.2	0.4	**23.1**
Nigerian Forcados	0.3	5.2		3.0	**8.4**
Algerian condensate			2.1	1.1	**3.2**
Total	**8.9**	**71.0**	**4.4**	**10.6**	**94.9**
Other Purchases Mtpa					
Mtbe	0.0	0.0		0.0	**0.0**
BTX return		0.0	0.3	0.1	**0.3**
Gas oil blending component	0.1	0.3	0.0	0.2	**0.6**
Methanol		0.0		0.0	**0.0**
Chemical return	0.0	0.0	0.1	0.2	**0.3**
Gofinate		1.6			**1.6**
Total	**0.1**	**1.9**	**0.3**	**0.6**	**2.9**
Blending Mtpa					
Refinery Gas		0.1	0.0		**0.1**
LPG		0.1	0.1	0.4	**1.7**
Chemical feed	0.6	0.5	0.0		**1.1**
Gasoline export		0.6		0.4	**1.0**
Gasoline UL 95	0.8	21.6	2.3	2.5	**27.2**
BTX feed		0.7		0.3	**1.0**
Avtur & kerosene	1.3	9.0	0.6	1.7	**12.6**
Automotive diesel	1.9	16.8	0.9	2.9	**22.5**
Heating oil		2.2		0.3	**2.5**
Other gas oil		2.5			**2.5**
Fuel oil 0.6%		0.3		0.1	**0.4**
Fuel oil 1%	0.0	5.5		0.1	**5.6**
Fuel oil 2%		0.9	0.2	0.8	**2.0**
Fuel oil 3.0%	0.8			0.1	**0.9**
Bunker	0.0	1.7			**1.7**
Lubes	0.8	1.1			**1.9**
Low S coke		0.7			**0.7**
Sulphur	0.0	0.4	0.0	0.0	**0.5**
Bitumen	1.1	1.5	0.3		**3.0**
Total	**7.4**	**67.3**	**4.5**	**9.7**	**88.9**

BENELUX

	Simple	FCC	HCU	FCC & HCU	Total System
Crude Purchase Mtpa					
Brent Blend	1.2	2.1	0.8	4.7	**8.7**
Iranian light		6.4	2.5	0.7	**9.7**
Kuwait	1.6	28.3	12.6	12.8	**55.3**
Nigerian Forcados		6.1	3.3	0.1	**9.4**
Total	**2.8**	**42.8**	**19.1**	**18.3**	**83.1**
Other Purchases Mtpa					
BTX return	0.0		0.3	0.0	**0.3**
Methanol		0.1	0.0	0.0	**0.1**
Natural gas				0.1	**0.1**
Chemical return		0.9	0.3	0.2	**1.5**
Total	**0.0**	**0.9**	**0.6**	**0.4**	**2.0**
Blending Mtpa					
Refinery Gas		0.1			**0.1**
LPG	0.0	1.0	0.4	0.4	**1.8**
Chemical feed	0.1	1.8	1.2	0.7	**3.8**
Gasoline export		3.4	0.6	1.0	**5.0**
Gasoline	0.4	5.5	2.7	2.4	**11.0**
BTX feed	0.1	0.0	0.3	0.7	**1.0**
Avtur & kerosene	0.1	1.8	1.8	1.6	**5.3**
Automotive diesel	0.3	7.7	3.9	4.9	**16.8**
Heating oil	0.5	2.4	2.8	1.5	**7.3**
Other gas oil	0.0	5.0	0.3	0.0	**5.4**
Fuel oil 0.6%		0.6			**0.6**
Fuel oil 1%		1.0			**1.0**
Bunker	0.5	6.1	4.9	3.0	**14.5**
Lubes	0.2			0.4	**0.6**
Sulphur	0.0	0.5	0.2	0.2	**0.9**
Bitumen		0.7		0.2	**0.9**
Gofinate		1.6			**1.6**
Total	**2.3**	**39.2**	**19.1**	**17.1**	**77.7**

GERMANY/AUSTRIA

	Simple	FCC	HCU	FCC & HCU	Total System
Crude Purchase Mtpa					
Brent Blend	3.3	27.3	3.4	5.2	**39.3**
Iranian light	0.3	7.1	1.1	4.5	**13.0**
Kuwait	5.5	17.1	13.1	0.2	**35.9**
Nigerian Forcados	0.5	18.0		0.7	**19.2**
Algerian condensate		3.1	0.9	0.5	**4.5**
Total	**9.6**	**72.6**	**18.5**	**11.1**	**111.8**
Other Purchases Mtpa					
Mtbe	0.0	0.3			**0.4**
BTX return	0.0		0.6		**0.6**
Gas oil blending component	0.2	4.8	0.9	0.0	**5.8**
Methanol		0.2		0.0	**0.2**
Chemical return	0.1	3.2	0.3	0.3	**3.9**
Total	**0.3**	**8.5**	**1.7**	**0.4**	**10.9**
Blending Mtpa					
Refinery Gas	0.2		0.1	0.4	**0.7**
LPG	0.2	3.1	0.5	0.3	**4.1**
Chemical feed	0.8	5.2	1.0	0.8	**7.9**
Gasoline	0.6	19.9	3.6	2.2	**26.3**
BTX feed	0.4		0.6	0.8	**1.8**
Avtur & kerosene	0.2	4.3		0.4	**4.9**
Automotive diesel	1.9	14.3	5.6	2.5	**24.3**
Heating oil		13.6			**13.6**
Other gas oil	1.7	5.6	4.6	2.4	**14.4**
Fuel oil 1%	0.0	4.9	0.7		**5.7**
Bunker	0.8	0.9			**1.7**
Lubes	0.6	0.6			**1.2**
Low S coke		0.5	0.3	0.5	**1.3**
High S coke	0.7	0.1	0.1	0.2	**1.1**
Sulphur	0.1	0.4	0.3	0.1	**0.8**
Bitumen		3.5			**3.5**
Total	**8.3**	**76.8**	**17.4**	**10.6**	**113.1**

FRANCE

	Simple	FCC	HCU	FCC & HCU	Total System
Crude Purchase Mtpa					
Brent Blend	2.2	12.7		0.3	**15.2**
Iranian light	0.0	28.8		5.6	**34.4**
Kuwait	1.6	15.4		1.9	**18.9**
Nigerian Forcados	0.5	17.4		1.6	**19.6**
Algerian condensate	0.4	0.6			**1.0**
Total	**4.7**	**74.9**	**0.0**	**9.4**	**89.0**
Other Purchases Mtpa					
Mtbe				0.1	**0.1**
BTX return	0.1			0.2	**0.3**
Gas oil blending component	1.3	2.9		0.0	**4.2**
Methanol		0.2		0.0	**0.2**
Natural gas				0.1	**0.1**
Chemical return	0.0	1.0		0.3	**1.3**
Total	**1.4**	**4.0**	**0.0**	**0.7**	**6.2**
Blending Mtpa					
Refinery Gas	0.1			0.0	**0.1**
LPG	0.1	2.7		0.1	**2.8**
Chemical feed	0.2	3.3		0.5	**4.0**
Gasoline export		3.0		0.0	**3.0**
Gasoline	0.6	13.6		1.9	**16.2**
Inter-EU Gasoline export		0.1		0.4	**0.5**
BTX feed	0.2	0.9			**1.0**
Avtur & kerosene	0.3	6.7			**7.0**
Automotive diesel	2.1	18.7		3.4	**24.3**
Heating oil		5.4		0.6	**6.0**
Other gas oil	0.6	4.9		0.5	**6.0**
Fuel oil 1%	0.4	1.4			**1.8**
Fuel oil 2%		1.6		0.2	**1.8**
Fuel oil 3.0%	0.3	4.6		1.1	**5.9**
Bunker		2.1		0.0	**2.1**
Lubes	0.4	1.0			**1.4**
Sulphur	0.0	0.5		0.1	**0.6**
Bitumen	0.2	2.5		0.4	**3.1**
Total	**5.4**	**72.9**	**0.0**	**9.4**	**87.8**

IBERIA

	Simple	FCC	HCU	FCC & HCU	Total System
Crude Purchase Mtpa					
Brent Blend	2.4	18.1	0.7	1.6	**22.7**
Iranian light	3.5	7.4	2.6	2.2	**15.8**
Kuwait	7.0	15.5	2.5	4.4	**29.4**
Nigerian Forcados	2.0	5.5	2.3	1.6	**11.4**
Algerian condensate	1.0				**1.0**
Total	**15.9**	**46.5**	**8.1**	**9.9**	**80.4**
Other Purchases Mtpa					
BTX return	0.2	0.0	0.1	0.0	**0.3**
Gas oil blending component		1.5	0.2	0.1	**1.8**
Methanol		0.1		0.0	**0.1**
Natural gas		1.1		0.1	**1.3**
Chemical return	0.4	0.2	0.1	0.3	**1.0**
Total	**0.6**	**2.9**	**0.4**	**0.6**	**4.4**
Blending Mtpa					
LPG	0.6	2.1	0.2	0.3	**3.2**
Chemical feed	0.4	2.5	0.2	0.5	**3.6**
Gasoline	2.7	8.6	1.0	1.4	**13.7**
Inter-EU Gasoline export		1.2	0.3	1.0	**2.4**
BTX feed	0.6	0.3	0.1	0.0	**1.0**
Avtur & kerosene	1.1	4.8	1.1	1.0	**8.0**
Automotive diesel	5.5	13.3	2.3	3.0	**24.0**
Heating oil	0.2	1.7	0.2	0.5	**2.7**
Other gas oil	0.2	2.1	0.2	0.2	**2.7**
Fuel oil 1%	0.3	1.1	0.1		**1.6**
Fuel oil 2%	1.3		2.2	0.0	**3.6**
Fuel oil 3.0%	0.4	1.9		1.4	**3.6**
Bunker		3.6			**3.6**
Lubes	0.3	0.6			**0.9**
High S coke		0.5			**0.5**
Sulphur	0.1	0.3	0.1	0.1	**0.5**
Bitumen	1.6	1.0		0.1	**2.7**
Total	**15.1**	**45.6**	**7.9**	**9.6**	**78.2**

ITALY/GREECE

	Simple	FCC	HCU	FCC & HCU	Total System
Crude Purchase Mtpa					
Brent Blend	12.9	14.3	2.3	14.6	**44.1**
Iranian light	2.6	11.9	6.6	8.9	**29.9**
Kuwait	10.0	10.0	7.0	15.3	**42.4**
Nigerian Forcados	2.8	0.9	0.7		**4.4**
Total	**28.3**	**37.0**	**16.6**	**38.8**	**120.7**
Other Purchases Mtpa					
BTX return	0.3				0.3
Methanol		0.1		0.1	**0.2**
Natural gas		0.4	0.2	0.4	**1.0**
Chemical return	0.1	0.5	0.0	0.2	**0.8**
Total	**0.4**	**1.0**	**0.2**	**0.7**	**2.3**
Blending Mtpa					
Refinery Gas	0.1				**0.1**
LPG	0.8	1.3	0.8	1.6	**4.5**
Chemical feed	1.3	2.7	0.8	2.6	**7.4**
Gasoline export		0.3		0.7	**1.0**
Gasoline	3.4	6.6	3.2	7.8	**21.0**
Inter-EU Gasoline export		0.7		1.1	**1.8**
BTX feed	0.6		0.4		**1.0**
Avtur & kerosene	2.1	3.6	0.8	2.9	**9.4**
Automotive diesel	7.0	8.4	5.1	12.6	**33.1**
Heating oil	1.6	1.3	1.1	0.6	**4.5**
Other gas oil	0.3	2.1	0.7	1.4	**4.5**
Fuel oil 0.6%	0.0		0.2		**0.2**
Fuel oil 1%	4.0	2.6	0.7	1.6	**8.9**
Fuel oil 3.0%	0.4		1.3	0.4	**2.1**
Bunker		1.7		3.4	**5.1**
Lubes	0.6	0.7			**1.3**
Low S coke		0.2			**0.2**
High S coke		0.5			**0.5**
Sulphur	0.2	0.3	0.1	0.3	**0.9**
Heavy residue			1.4	1.6	**3.0**
Bitumen	1.2	1.0		0.1	**2.3**
Total	**23.4**	**33.9**	**16.6**	**38.9**	**112.8**

APPENDIX 3 EQUATIONS USED TO CALCULATE COSTS AND CO_2 EMISSIONS

// Added capacity calculations

Plant capacity added above reference capacity Mtpa = if(Plant throughput MTPA New plant >0
, Plant throughput MTPA New plant ,"-")

Hydrotreater added = If((Plant throughput Mtpa.Hydrotreater - Plant throughput Mtpa.Hydrotreater:d1404) >0,
(Plant throughput Mtpa.Hydrotreater - Plant throughput Mtpa.Hydrotreater:d1404),0) +
if((Plant throughput Mtpa.Reformer LP - Plant throughput Mtpa.Reformer LP:d1404)>0,
(Plant throughput Mtpa.Reformer LP - Plant throughput Mtpa.Reformer LP:d1404),0) +
if((Plant throughput Mtpa.Reformer HP - Plant throughput Mtpa.Reformer HP:d1404)>0,
(Plant throughput Mtpa.Reformer HP - Plant throughput Mtpa.Reformer HP:d1404),0) +
if((Plant throughput Mtpa.Hydrodesulphuriser LP - Plant throughput Mtpa.Hydrodesulphuriser LP:d1404)>0, (Plant throughput Mtpa.Hydrodesulphuriser LP - Plant throughput Mtpa.Hydrodesulphuriser LP:d1404),0)

// The need to Hydrotreat Kerosene to achieve ultra low sulphur levels in Diesel is back calculated via changes in existing Hydrotreater utilisation, changes in Reformer utilisation and changes in LP HDS utilisation releasing these units for HTU service.//

// Establish the number of process units added based on scale & type.

Number of Process units = if(Plant capacity added above reference capacity Mtpa >0,
if(Investment::Internal:Scale = "Typical",
Plant capacity added above reference capacity Mtpa / Investment::Internal:Typical capacity Mtpa ,
if(Plant capacity added above reference capacity Mtpa / Number of Refineries >Investment::Internal:Min capacity Mtpa , Number of Refineries ,
Plant capacity added above reference capacity Mtpa / Investment::Internal:Min capacity Mtpa)),"-")

// Investment Calculations

'Investment in added process plant. MUS$'.Excluding Total = if (Plant capacity added above reference capacity Mtpa >0,(Plant capacity added above reference capacity Mtpa / Number of Process units / Investment::Typical capacity Mtpa:Internal) ^ 0.6 * Investment::Base cost M$:Internal *Number of Process units , "-")

//Reformer LP investment =0

//Bitumen investment = 0

//Lubes investment = 0

MCN Reformer upgrade = if (MCN Reformer added >0,
Number of Refineries * Investment::MCN Reforming:Internal:Base cost M$, "-")

// Modifications required to enable FCCU naphtha reforming are estimated at $20 millions per plant requiring this operation.

Other Investment MUS$.Total = groupsum(Other Investment MUS$)

// *Investment Summary*

External MTBE Plants = Other Purchases.Mtbe / Investment::External:Typical capacity Mtpa:MTBE plant *
Investment::External:Base cost M$:MTBE plant

External Methanol Plant = Other Purchases.Mtbe *0.37/ Investment::External:Typical capacity Mtpa:'Butamer (Internal) ,Methanol (External)' * Investment::External:Base cost M$:'Butamer (Internal) ,Methanol (External)'

External Methanol Plant =(Other Purchases.Mtbe *0.37/ Investment::External:Typical capacity Mtpa:'Butamer (Internal) ,Methanol (External)' +Methanol) * Investment::External:Base cost M$:'Butamer (Internal) ,Methanol (External)'

// *Modified 1/12/1998 to account for investment required to satisfy internal refinery Methanol demand.*

Other Investment MUS$.Hydrogen recovery =(Consumed.Total - Produced.Hydrogen unit - Produced.Hydrogen unit new) * 500

Offsite facilites for transfers = if (Transfers Ex.Total >0, Number of Refineries * 5.0,0) + if(Transfers To.Total > 0, Number of Refineries * 1.0,0) Number of Refineries = Capacity::Number of Refineries

// Material Balance Calculations

Blending Mtpa.Total = groupsum(Blending Mtpa)

Refinery Fuel.Total = groupsum(Refinery Fuel)

Losses.Total = groupsum(Losses)

Crude Purchase.Total = groupsum(Crude Purchase)

Other Purchases.Total = groupsum(Other Purchases)

Transfers Ex.Total = groupsum(Transfers Ex)

Transfers To.Total = groupsum(Transfers To)

// *Totalising all investment in one refinery type is put here to be able to see the effect of the eliminating some savings in the delta calculations.*

'Investment in added process plant. MUS$'.Total = groupsum('Investment in added process plant. MUS$')

// *External Investment Calculations*

// *Totalising of refinery types are put her to ensure consistency across types with total system investments.*

All Refineries.Total System =if (groupsum(All Refineries)>0, groupsum(All Refineries), "-")

// Utilisation Calculations

Utilisation percent of reference capacity =If (Capacity::Reference Capacity>0, Plant throughput Mtpa / Capacity::Reference Capacity,"-")

// Matrial Balance

Material Balance = if ((Crude Purchase.Total + Other Purchases.Total + Transfers Ex.Total) <>0, (Transfers To.Total + Blending Mtpa.Total+ Refinery Fuel.Total + Losses.Total) / (Crude Purchase.Total + Other Purchases.Total + Transfers Ex.Total) , "-")

// Incremental investment over base case

Total Internal Investment = 'Investment in added process plant. MUS$'.Total - 'Investment in added process plant. MUS$'.Total:d1404 + Offsite facilites for transfers - Offsite facilites for transfers:d1404 + Other Investment MUS$.Hydrogen recovery - Other Investment MUS$.Hydrogen recovery:d1404

Total External Investment = External MTBE Plants - External MTBE Plants:d1404 + External Methanol Plant - External Methanol Plant:d1404

Incremental Investment MUS$. Total additional Investment = groupsum(Incremental Investment MUS$)

// *Energy and Carbon balance calculations. Incremental over base case* .

Kuwait CO_2 EU = (Crude Purchase.Kuwait - Crude Purchase.Kuwait:d1404) * 'Feedstock & fixed'::Kuwait:Carbon wt% *44/12

Methanol CO_2 EU = (Methanol - Methanol:d1404) * 'Feedstock & fixed'::Methanol:Carbon wt% * 44/12

MTBE CO_2 EU = (Mtbe - Mtbe:d1404) * 'Feedstock & fixed'::Mtbe:Carbon wt% * 44/12

CO_2 EU Mtpa.Total = groupsum(CO_2 EU Mtpa)

Crude CO_2 =(Crude Purchase.Kuwait - Crude Purchase.Kuwait:d1404) * 'Feedstock & fixed'::Kuwait:Carbon wt% * 44/12

Natural Gas CO_2 =(0.67*(Methanol - Methanol:d1404) + 0.67*0.37*(Mtbe - Mtbe:d1404)) * 'Feedstock & fixed'::Natural Gas:Carbon wt% * 44/12

CO_2 EU Mtpa.Natural Gas Imports CO_2 =(Natural gas - Natural gas:d1404) * 'Feedstock & fixed'::Natural Gas:Carbon wt% * 44/12

Global CO_2 Mtpa.Natural Gas Imports CO_2 = (Natural gas - Natural gas:d1404) * 'Feedstock & fixed'::Natural Gas:Carbon wt% * 44/12

Field Butane CO_2 = 0.76*(Mtbe - Mtbe:d1404) * 'Feedstock & fixed'::Field Butane:Carbon wt% * 44/12

Global CO_2 Mtpa.Total = groupsum(Global CO_2 Mtpa)

Crude Value = (Crude Purchase.Kuwait - Crude Purchase.Kuwait:d1404) * 150

Natural Gas Value = 1.11*(0.67*(Methanol - Methanol:d1404) + 0.67*0.37*(Mtbe - Mtbe:d1404)) * 150

Natural gas imports = (Natural gas -Natural gas:d1404) * 200

Field Butane Value = 1.09* 0.76*(Mtbe - Mtbe:d1404) * 150

'Value @ $150 per TOE MUS$'.Total = groupsum('Value @ $150 per TOE MUS$')

// Maintenance operating cost and overheads. All calculated as cost above base case.

'Maintenance, ops & OH' = (1+ 0.2) * (1+ 0.2) * (Total Internal Investment) * 0.03

// Maintenance cost estimated to be 3% of Capital Investment, Operating Labour 20% of Maintenance costs. Overhead 20% of Operating labour plus maintenance costs.

Transfer costs = (Transfers Ex.Total - Transfers Ex.Total:d1404) * 12

'Energy cost (global)' = 'Value @ $150 per TOE MUS$'.Total

Cetane additive = if(Select(Specifications Diesel::AGO1 Cetane index:Limit, Specifications Diesel::Spec limit:Limit, Diesel case&"-Min")<=55, (Select(Specifications Diesel::AGO1 Cetane index:Limit, Specifications Diesel::Spec limit:Limit, Diesel case&"-Min") - Select(Specifications Diesel::AGO1 Cetane index:Limit, Specifications Diesel::Spec limit:Limit, d1404:Diesel case&"-Min")) * 'AGO1 Automotive Diesel , Mtpa' * 0.4 *2/3, (3-1)*'AGO1 Automotive Diesel , Mtpa' * 0.4)

// Cetane additive = if(Select(Specifications Diesel::AGO1 Cetane index:Limit, Specifications Diesel::Spec limit:Limit, Diesel case&"-Min")<=55, (Select(Specifications Diesel::AGO1 Cetane index:Limit, Specifications Diesel::Spec limit:Limit, Diesel case&"-Min") - Select(Specifications Diesel::AGO1 Cetane index:Limit, Specifications Diesel::Spec limit:Limit, ecur2:Diesel case&"-Min")) * 'AGO1 Automotive Diesel , Mtpa' * 0.4 *2/3, (3-1)*'AGO1 Automotive Diesel , Mtpa' * 0.4)'

// Both of the above equations were superseded in the revised Cetane Number cost study. As the base case contains the maximum average dosage of cetane improver additive (3 CN points) the delta Cetane additive costs are all set at 0.

External maintenance, ops & OH' = (1+ 0.2) * (1+ 0.2) * (Total External Investment) * 0.03
// Maintenance cost estimated to be 3% of Capital Investment, Operating Labour 20% of Maintenance costs. Overhead 20% of Operating labour plus maintenance costs.

Incremental Operating costs M$ pa.Total additional operating cost M$ pa = groupsum(Incremental Operating costs M$ pa)

// *Net Present Value (Consistent with AO1 explanatory memorandum, but not with Touche Report)*

// *Incremental over base case*

Net Present Value M$ = Total additional Investment + Total additional operating cost M$ pa * 9.75 - 'Value power @ $60/MWH M$' * 9.75

Net Present Value MEuro = Net Present Value M$ /1.1

APPENDIX 4 EXAMPLES OF CAPITAL COSTS (M$) BY UNIT TYPE BY REFINERY TYPE BY REGION

Sum EU15	f09y0 Simple	FCC	HCU	FCC & HCU	total System	f14y4 Simple	FCC	HCU	FCC & HCU	Total System
Number of Refineries	27	44	10	13	94	27	44	10	13	94
Investment in added process plant. MUS$										
Distiller investment	0	0	0	0	0	0	0	0	3	3
Vac Dist investment	0	0	0	0	0	0	5	0	0	5
Visbreaker investment	1	0	0	0	1	0	0	0	0	0
Reformer LP investment	0	0	0	0	0	0	0	0	0	0
Reformer HP investment	0	0	0	5	5	0	0	0	0	0
MCN Reformer upgrade	0	820	60	180	1060	40	860	80	200	1180
Platformate splitter investment	0	2	0	0	3	0	2	0	4	6
Hydrotreater investment	0	0	0	0	0	44	111	29	81	265
Hydrodesulphuriser LP investment	0	0	0	0	0	0	0	0	0	0
Hydrodesulphuriser MP investment	0	0	0	0	0	0	0	0	0	0
Hydrodesulphuriser HP investment	0	0	0	10	10	714	2328	524	556	4122
Bitumen investment	0	0	0	0	0	0	0	0	0	0
Lubes investment	0	0	0	0	0	0	0	0	4	4
Hydrogen investment	0	3	0	5	8	68	178	55	68	368
Delayed coker investment	0	0	0	0	0	0	0	0	0	0
Alky investment	0	19	0	0	19	8	247	0	0	255
Isom o/t investment	0	0	0	0	0	0	0	0	0	0
Isom rec investment	3	0	0	0	3	209	516	165	270	1160
LPL isom investment	0	0	0	3	3	0	3	0	28	31
MTBE investment	0	4	0	25	29	0	27	0	27	55
Butamer investment	0	0	0	0	0	0	0	0	0	0
Sulphur investment	0	0	0	0	0	8	35	16	0	58
Tame investment	0	0	0	0	0	0	27	0	12	39
Residue Desulph investment	0	0	0	0	0	0	0	0	0	0
HP LCO dearom. investment	0	0	0	0	0	0	0	0	0	0
2 stage hydrogen. investment	0	0	0	0	0	0	67	0	0	67
HCCG hydrotreater investment	0	0	0	0	0	67	530	8	84	690
Cat cracker investment	0	0	0	0	0	26	0	6	0	32
Hydro resid con investment	0	0	0	6	6	0	29	0	0	29
Hydrocracker rec. investment	0	0	0	0	0	0	0	0	0	0
Hydrocracker o/t investment	0	8	0	0	8	52	88	0	0	140
Gofiner investment	5	0	0	0	5	32	19	4	2	57
LCCG Splitter inv	0	0	0	2	2	2	23	0	6	32
LCCG Merox extraction inv	0	0	0	0	0	3	59	8	7	78
FGDWL inv	0	0	0	0	0	0	0	0	0	0
Total	10	856	60	237	1163	1273	5156	894	1351	8676
Other Investment MUS$										
External MTBE Plants	11	272	0	70	353	291	322	186	395	1194
External Methanol Plant	5	368	1	107	482	123	406	80	243	851
Hydrogen recovery	95	480	115	190	880	65	445	95	155	760
Offsite facilites for transfers	123	198	39	57	417	158	249	58	61	526
Total	234	1318	155	424	2131	637	1422	418	853	3331
Incremental Investment MUS$										
Total Internal Investment	0	0	0	0	0	1269	4316	833	1084	7501
Total External Investment	0	0	0	0	0	398	88	264	460	1210
Total additional Investment	0	0	0	0	0	1667	4403	1097	1544	8711
CO2 EU Mtpa										
Kuwait CO2 EU					0					2.10
Methanol CO2 EU					0					0.05
MTBE CO2 EU					0					3.00
Total					0					5.15
Global CO2 Mtpa					0					0.00
Crude CO2					0					2.10
Natural Gas CO2					0					0.90
Field Butane CO2					0					2.78
Total					0					5.77
Value @ $150 per TOE MUS$										
Crude Value					0					99.8
Natural Gas Value					0					53.5
Field Butane Value					0					149.2
Total					0					302.5
Incremental Operating costs M$ pa					0					0.0
Maintenance, ops & OH					0					324.1
Transfer costs					0					-18.1
Energy cost (global)					0					302.5
Cetane additive					0					0.0
External maintenance, ops & OH					0					52.3
Total additional operating cost M$ pa					0					660.7
Net Present Value M$					0					15154
Net Present Value MEcu					0					13776

Scandinavia	a09y0					a14y4				
	Simple	FCC	HCU	FCC & HCU	Total System	Simple	FCC	HCU	FCC & HCU	Total System
Number of Refineries	6	1		2	9	6	1		2	9
Investment in added process plant. MUS$										
Distiller investment										
Vac Dist investment										
Visbreaker investment										
Reformer LP investment										
Reformer HP investment				5	5					
MCN Reformer upgrade		20			20					
Platformate splitter investment									1	1
Hydrotreater investment							1		32	33
Hydrodesulphuriser LP investment										
Hydrodesulphuriser MP investment										
Hydrodesulphuriser HP investment						37	4			41
Bitumen investment										
Lubes investment										
Hydrogen investment						18	3			20
Delayed coker investment										
Alky investment						8	3			11
Isom o/t investment										
Isom rec investment						45			45	89
LPL isom investment									6	6
MTBE investment										
Butamer investment										
Sulphur investment										
Tame investment							2		6	8
Residue Desulph investment										
HP LCO dearom. investment										
2 stage hydrogen. investment										
HCCG hydrotreater investment							4		13	16
Cat cracker investment						26				26
Hydro resid con investment										
Hydrocracker rec. investment										
Hydrocracker o/t investment						52	7			59
Gofiner investment						18				18
LCCG Splitter inv							1			1
LCCG Merox extraction inv										
FGDWL inv										
Total	0	20	0	5	25	203	24	0	102	330
Other Investment MUS$										
External MTBE Plants	0	0	0	0		38	0	0	0	38
External Methanol Plant	0	3	0	13	16	16	4	0	12	32
Hydrogen recovery	25	0	0	35	60	15	0	0	30	45
Offsite facilites for transfers	36	6	0	10	52	36	6	0	10	52
Total	61	9	0	58	128	105	10	0	52	166
Incremental Investment MUS$										
Total Internal Investment	0	0	0	0	0	193	4	0	92	289
Total External Investment	0	0	0	0	0	54	1	0	-1	53
Total additional Investment	0	0	0	0	0	247	5	0	90	342
CO2 EU Mtpa										
Kuwait CO2 EU					0.0					0.07
Methanol CO2 EU					0.0					0.00
MTBE CO2 EU					0.0					0.14
Total					0.0					0.20
Global CO2 Mtpa										
Crude CO2					0.0					0.07
Natural Gas CO2					0.0					0.04
Field Butane CO2					0.0					0.12
Total					0.0					0.23
Value @ $150 per TOE MUS$										
Crude Value					0.0					3.2
Natural Gas Value					0.0					2.1
Field Butane Value					0.0					6.7
Total					0.0					12.0
Incremental Operating costs M$ pa										
Maintenance, ops & OH					0.0					12.5
Transfer costs					0.0					-4.5
Energy cost (global)					0.0					12.0
Cetane additive					0.0					0.0
External maintenance, ops & OH					0.0					2.3
Total additional operating cost M$ pa					0.0					22.2
Net Present Value M$					0					559
Net Present Value MEuro					0					508

UK & Ireland	u09y0 Simple	FCC	HCU	FCC & HCU	Total System	u14y4 Simple	FCC	HCU	FCC & HCU	Total System
Number of Refineries	2	7	1	1	11	2	7	1	1	11
Investment in added process plant. MUS$										
Distiller investment				0	0				3	3
Vac Dist investment										
Visbreaker investment	1				1					
Reformer LP investment										
Reformer HP investment										
MCN Reformer upgrade		140	20		160		140			140
Platformate splitter investment		0		0	0		2		3	5
Hydrotreater investment							46		1	47
Hydrodesulphuriser LP investment										
Hydrodesulphuriser MP investment										
Hydrodesulphuriser HP investment						16	508	23	6	553
Bitumen investment										
Lubes investment										
Hydrogen investment		3			3		30	3	3	35
Delayed coker investment										
Alky investment										
Isom o/t investment										
Isom rec investment						6				6
LPL isom investment							3		22	25
MTBE investment				6	6				6	6
Butamer investment										
Sulphur investment							8			8
Tame investment							14			14
Residue Desulph investment										
HP LCO dearom. investment										
2 stage hydrogen. investment							16			16
HCCG hydrotreater investment							69			69
Cat cracker investment										
Hydro resid con investment										
Hydrocracker rec. investment										
Hydrocracker o/t investment		8			8		53			53
Gofiner investment										
LCCG Splitter inv										
LCCG Merox extraction inv										
FGDWL inv										
Total	1	151	20	6	179	22	890	26	43	980
Other Investment MUS$										
External MTBE Plants	5	27	0	2	34	28	15	30	0	74
External Methanol Plant	2	12	0	6	20	12	8	13	4	37
Hydrogen recovery	5	120	15	15	155	5	125	15	15	160
Offsite facilites for transfers	12	42	6	6	66	12	42	6	6	66
Total	24	200	21	29	274	57	191	64	25	337
Incremental Investment MUS$										
Total Internal Investment	0	0	0	0	0	21	744	6	36	807
Total External Investment	0	0	0	0	0	33	-15	43	-4	57
Total additional Investment	0	0	0	0	0	54	729	49	32	864
CO2 EU Mtpa										
Kuwait CO2 EU					0					0.38
Methanol CO2 EU					0					0.00
MTBE CO2 EU					0					0.14
Total					0					0.52
Global CO2 Mtpa										
Crude CO2					0					0.38
Natural Gas CO2					0					0.04
Field Butane CO2					0					0.13
Total					0					0.55
Value @ $150 per TOE MUS$										
Crude Value					0					18.0
Natural Gas Value					0					2.5
Field Butane Value					0					7.1
Total					0					27.5
Incremental Operating costs M$ pa										
Maintenance, ops & OH					0					34.9
Transfer costs					0					-4.9
Energy cost (global)					0					27.5
Cetane additive					0					0.0
External maintenance, ops & OH					0					2.5
Total additional operating cost M$ pa					0					60.0
Net Present Value M$					0					1,449
Net Present Value MEcu					0					1,317

Benelux	c09y0 Simple	FCC	HCU	FCC & HCU	Total System	c14y4 Simple	FCC	HCU	FCC & HCU	Total System
Number of Refineries	2	3	3	1	9	2	3	3	1	9
Investment in added process plant. MUS$										
Distiller investment										
Vac Dist investment										
Visbreaker investment										
Reformer LP investment										
Reformer HP investment										
MCN Reformer upgrade							60		20	80
Platformate splitter investment	0	0	0		0					
Hydrotreater investment								6	32	38
Hydrodesulphuriser LP investment										
Hydrodesulphuriser MP investment										
Hydrodesulphuriser HP investment						21	72	151	69	313
Bitumen investment										
Lubes investment									4	4
Hydrogen investment						3	23	20		45
Delayed coker investment										
Alky investment										
Isom o/t investment										
Isom rec investment						2	82	45	29	157
LPL isom investment										
MTBE investment							8		4	12
Butamer investment										
Sulphur investment							8	4		12
Tame investment										
Residue Desulph investment										
HP LCO dearom. investment										
2 stage hydrogen. investment										
HCCG hydrotreater investment						1	23			24
Cat cracker investment										
Hydro resid con investment							29			29
Hydrocracker rec. investment										
Hydrocracker o/t investment							28			28
Gofiner investment							19		2	21
LCCG Splitter inv							1			1
LCCG Merox extraction inv										
FGDWL inv										
Total	0	0	0	0	0	26	352	225	159	763
Other Investment MUS$										
External MTBE Plants	0	0	0	0		3	0	32	5	39
External Methanol Plant	0	29	1	9	39	1	35	15	13	64
Hydrogen recovery	0	55	25	25	105	0	50	15	25	90
Offsite facilites for transfers	12	3	15	5	35	12	3	18	5	38
Total	12	87	41	39	179	16	88	79	48	231
Incremental Investment MUS$										
Total Internal Investment	0	0	0	0	0	25	347	218	160	751
Total External Investment	0	0	0	0	0	4	6	45	9	64
Total additional Investment	0	0	0	0	0	29	353	263	169	815
CO2 EU Mtpa										
Kuwait CO2 EU					0					0.59
Methanol CO2 EU					0					0.03
MTBE CO2 EU					0					0.14
Total					0					0.76
Global CO2 Mtpa										
Crude CO2					0					0.59
Natural Gas CO2					0					0.08
Field Butane CO2					0					0.13
Total					0					0.80
Value @ $150 per TOE MUS$										
Crude Value					0					28.1
Natural Gas Value					0					4.7
Field Butane Value					0					7.0
Total					0					39.7
Incremental Operating costs M$ pa										
Maintenance, ops & OH					0					32.4
Transfer costs					0					0.3
Energy cost (global)					0					39.7
Cetane additive					0					0.0
External maintenance, ops & OH					0					2.8
Total additional operating cost M$ pa					0					75.1
Net Present Value M$					0					1,547
Net Present Value MEcu					0					1,407

Germany & Austria	d09y0 Simple	FCC	HCU	FCC & HCU	Total System	d14y4 Simple	FCC	HCU	FCC & HCU	Total System
Number of Refineries	2	10	3	1	16	2	10	3	1	16
Investment in added process plant. MUS$										
Distiller investment										
Vac Dist investment										
Visbreaker investment										
Reformer LP investment										
Reformer HP investment										
MCN Reformer upgrade		200		20	220	40	200	60	20	320
Platformate splitter investment		2			2					
Hydrotreater investment						14	6		1	20
Hydrodesulphuriser LP investment										
Hydrodesulphuriser MP investment										
Hydrodesulphuriser HP investment						90	390	149	62	690
Bitumen investment										
Lubes investment										
Hydrogen investment						8	10	20	13	50
Delayed coker investment										
Alky investment		19			19		217			217
Isom o/t investment										
Isom rec investment	3				3	54	197	51	46	348
LPL isom investment										
MTBE investment		2		8	10				8	8
Butamer investment										
Sulphur investment						4	4	8		16
Tame investment										
Residue Desulph investment										
HP LCO dearom. investment										
2 stage hydrogen. investment										
HCCG hydrotreater investment						24	253	4	27	309
Cat cracker investment								6		6
Hydro resid con investment										
Hydrocracker rec. investment										
Hydrocracker o/t investment										
Gofiner investment						15		4		19
LCCG Splitter inv		0		1	1	2	12	0	4	19
LCCG Merox extraction inv						3	25	8	6	42
FGDWL inv										
Total	3	223	0	29	255	253	1,314	310	186	2,063
Other Investment MUS$										
External MTBE Plants	6	242	0	0	248	71	25	56	0	152
External Methanol Plant	3	191	0	6	200	30	97	24	6	157
Hydrogen recovery	5	105	35	25	170	5	85	30	15	135
Offsite facilites for transfers	2	50	3	0	55	12	60	18	5	95
Total	16	587	38	31	673	118	268	128	26	539
Incremental Investment MUS$										
Total Internal Investment	0	0	0	0	0	260	1,081	320	152	1,813
Total External Investment	0	0	0	0	0	92	-310	80	0	-139
Total additional Investment	0	0	0	0	0	352	771	400	152	1,675
CO2 EU Mtpa										
Kuwait CO2 EU					0					2.49
Methanol CO2 EU					0					-0.01
MTBE CO2 EU					0					-0.34
Total					0					2.14
Global CO2 Mtpa										
Crude CO2					0					2.49
Natural Gas CO2					0					-0.11
Field Butane CO2					0					-0.32
Total					0					2.07
Value @ $150 per TOE MUS$										
Crude Value					0					118.4
Natural Gas Value					0					-6.3
Field Butane Value					0					-17.0
Total					0					95.0
Incremental Operating costs M$ pa										
Maintenance, ops & OH					0					78.3
Transfer costs					0					6.9
Energy cost (global)					0					95.0
Cetane additive					0					0.0
External maintenance, ops & OH					0					-6.0
Total additional operating cost M$ pa					0					174.2
Net Present Value M$					0					3,373
Net Present Value MEcu					0					3,067

France	f09y0					f14y4				
	Simple	FCC	HCU	FCC & HCU	total System	Simple	FCC	HCU	FCC & HCU	Total System
Number of Refineries	1	11	0	1	13	1	11	0	1	13
Investment in added process plant. MUS$										
Distiller investment										
Vac Dist investment										
Visbreaker investment										
Reformer LP investment										
Reformer HP investment										
MCN Reformer upgrade		220		20	240		220		20	240
Platformate splitter investment	0				0					
Hydrotreater investment							24			24
Hydrodesulphuriser LP investment										
Hydrodesulphuriser MP investment										
Hydrodesulphuriser HP investment						46	664		83	794
Bitumen investment										
Lubes investment										
Hydrogen investment				5	5		58		18	75
Delayed coker investment										
Alky investment										
Isom o/t investment										
Isom rec investment									37	37
LPL isom investment				3	3					
MTBE investment				6	6				8	8
Butamer investment										
Sulphur investment							8			8
Tame investment										
Residue Desulph investment										
HP LCO dearom. investment										
2 stage hydrogen. investment							51			51
HCCG hydrotreater investment							92			92
Cat cracker investment										
Hydro resid con investment										
Hydrocracker rec. investment										
Hydrocracker o/t investment										
Gofiner investment										
LCCG Splitter inv		0			0					
LCCG Merox extraction inv							6			6
FGDWL inv										
Total	0	220	0	34	254	46	1,122	0	165	1,334
Other Investment MUS$										
External MTBE Plants	0	0	0	68	68	7	279	0	25	312
External Methanol Plant	0	72	0	34	105	3	185	0	16	203
Hydrogen recovery	5	90	0	10	105	0	90	0	5	95
Offsite facilites for transfers	1	55	0	6	62	6	66	0	5	77
Total	6	217	0	117	340	16	620	0	51	687
Incremental Investment MUS$										
Total Internal Investment	0	0	0	0	0	46	913	0	125	1,084
Total External Investment	0	0	0	0	0	10	392	0	-60	342
Total additional Investment	0	0	0	0	0	56	1,305	0	65	1,426
CO2 EU Mtpa										
Kuwait CO2 EU					0					-0.37
Methanol CO2 EU					0					-0.02
MTBE CO2 EU					0					0.87
Total					0					0.49
Global CO2 Mtpa										
Crude CO2					0					-0.37
Natural Gas CO2					0					0.22
Field Butane CO2					0					0.80
Total					0					0.66
Value @ $150 per TOE MUS$										
Crude Value					0					-17.4
Natural Gas Value					0					13.0
Field Butane Value					0					43.2
Total					0					38.9
Incremental Operating costs M$ pa										
Maintenance, ops & OH					0					46.8
Transfer costs					0					-1.4
Energy cost (global)					0					38.9
Cetane additive					0					0.0
External maintenance, ops & OH					0					14.8
Total additional operating cost M$ pa					0					99.1
Net Present Value M$					0					2,392
Net Present Value MEcu					0					2,175

Iberia	s09y0 Simple	FCC	HCU	FCC & HCU	Total System	s14y4 Simple	FCC	HCU	FCC & HCU	Total System
Number of Refineries	4	6	1	1	12	4	6	1	1	12
Investment in added process plant. MUS$										
Distiller investment										
Vac Dist investment										
Visbreaker investment										
Reformer LP investment										
Reformer HP investment										
MCN Reformer upgrade		120		20	140		120	20	20	160
Platformate splitter investment										
Hydrotreater investment						20			1	21
Hydrodesulphuriser LP investment										
Hydrodesulphuriser MP investment										
Hydrodesulphuriser HP investment						185	392	78	68	723
Bitumen investment										
Lubes investment										
Hydrogen investment						15	30		10	55
Delayed coker investment										
Alky investment							27			27
Isom o/t investment										
Isom rec investment						26	137	13	43	219
LPL isom investment										
MTBE investment		2			2		18			18
Butamer investment										
Sulphur investment						4	4	4		12
Tame investment							12		6	18
Residue Desulph investment										
HP LCO dearom. investment										
2 stage hydrogen. investment										
HCCG hydrotreater investment						15	33	4	17	69
Cat cracker investment										
Hydro resid con investment										
Hydrocracker rec. investment										
Hydrocracker o/t investment										
Gofiner investment										
LCCG Splitter inv				0	0		8		2	10
LCCG Merox extraction inv							13		2	14
FGDWL inv										
Total	0	122	0	20	142	264	794	118	168	1,345
Other Investment MUS$										
External MTBE Plants	0	0	0	0		56	0	18	0	74
External Methanol Plant	0	29	0	5	34	24	43	7	6	80
Hydrogen recovery	20	65	10	10	105	15	55	10	10	90
Offsite facilites for transfers	0	6	5	0	11	20	36	6	0	62
Total	20	100	15	15	150	115	134	41	16	305
Incremental Investment MUS$										
Total Internal Investment	0	0	0	0	0	279	692	119	148	1,238
Total External Investment	0	0	0	0	0	80	14	25	1	119
Total additional Investment	0	0	0	0	0	359	706	144	149	1,357
CO2 EU Mtpa										
Kuwait CO2 EU					0					0.47
Methanol CO2 EU					0					0.05
MTBE CO2 EU					0					0.26
Total					0					0.78
Global CO2 Mtpa										
Crude CO2					0					0.47
Natural Gas CO2					0					0.14
Field Butane CO2					0					0.24
Total					0					0.85
Value @ $150 per TOE MUS$										
Crude Value					0					22.2
Natural Gas Value					0					8.3
Field Butane Value					0					13.0
Total					0					43.6
Incremental Operating costs M$ pa										
Maintenance, ops & OH					0					53.5
Transfer costs					0					4.6
Energy cost (global)					0					43.6
Cetane additive					0					0.0
External maintenance, ops & OH					0					5.1
Total additional operating cost M$ pa					0					106.9
Net Present Value M$					0					2,399
Net Present Value MEcu					0					2,181

Italy & Greece	i09y0 Simple	FCC	HCU	FCC & HCU	Total System	i14y4 Simple	FCC	HCU	FCC & HCU	Total System
Number of Refineries	10	6	2	6	24	10	6	2	6	24
Investment in added process plant. MUS$										
Distiller investment										
Vac Dist investment							5			5
Visbreaker investment										
Reformer LP investment										
Reformer HP investment										
MCN Reformer upgrade		120	40	120	280		120		120	240
Platformate splitter investment										
Hydrotreater investment						10	33	23	14	81
Hydrodesulphuriser LP investment										
Hydrodesulphuriser MP investment										
Hydrodesulphuriser HP investment				10	10	319	298	123	269	1,009
Bitumen investment										
Lubes investment										
Hydrogen investment						25	25	13	25	88
Delayed coker investment										
Alky investment										
Isom o/t investment										
Isom rec investment						77	101	56	70	304
LPL isom investment										
MTBE investment				6	6		2		2	4
Butamer investment										
Sulphur investment							4			4
Tame investment										
Residue Desulph investment										
HP LCO dearom. investment										
2 stage hydrogen. investment										
HCCG hydrotreater investment						27	56		28	111
Cat cracker investment										
Hydro resid con investment				6	6					
Hydrocracker rec. investment										
Hydrocracker o/t investment										
Gofiner investment	5				5					
LCCG Splitter inv				1	1		1			1
LCCG Merox extraction inv							16			16
FGDWL inv										
Total	5	120	40	143	307	458	660	215	528	1,861
Other Investment MUS$										
External MTBE Plants	0	4	0	0	4	89	2	50	365	506
External Methanol Plant	0	33	0	34	67	38	34	21	185	278
Hydrogen recovery	35	45	30	70	180	25	40	25	55	145
Offsite facilites for transfers	60	36	10	30	136	60	36	10	30	136
Total	95	118	40	134	387	211	113	107	635	1,066
Incremental Investment MUS$										
Total Internal Investment	0	0	0	0	0	444	535	170	370	1,518
Total External Investment	0	0	0	0	0	126	0	72	516	714
Total additional Investment	0	0	0	0	0	570	534	242	886	2,232
CO2 EU Mtpa										
Kuwait CO2 EU					0					-1.53
Methanol CO2 EU					0					-0.01
MTBE CO2 EU					0					1.80
Total					0					0.26
Global CO2 Mtpa										
Crude CO2					0					-1.53
Natural Gas CO2					0					0.49
Field Butane CO2					0					1.66
Total					0					0.62
Value @ $150 per TOE MUS$										
Crude Value					0					-72.6
Natural Gas Value					0					29.2
Field Butane Value					0					89.2
Total					0					45.8
Incremental Operating costs M$ pa										
Maintenance, ops & OH					0					65.6
Transfer costs					0					-19.0
Energy cost (global)					0					45.8
Cetane additive					0					0.0
External maintenance, ops & OH					0					30.8
Total additional operating cost M$ pa					0					123.2
Net Present Value M$					0					3,433
Net Present Value MEcu					0					3,121

APPENDIX 5 EU-15 SUMMARY OF INVESTMENT & OPERATING COSTS AND NPV RESULTS

STF-9 cases excluding higher CN cases

	09y0	09y1	09y2	09y3	09y4	10y0	11y0	11y4	12y0	14y0	14y2	14y4
Investment in added process plant. MUS$												
Distiller investment	0	.	1	1	4	1	2	3	.	1	2	3
Vac Dist investment	.	5	2	2	2	.	3	3	1	3	9	5
Visbreaker investment	1	0	1	1	0	1	1	0	.	1	1	.
Reformer LP investment	.	.	.	.	2	9	13	57	1	.	.	.
Reformer HP investment	5	5	7	8	7	4	5	12	6	.	.	.
MCN Reformer upgrade	1060	1180	1060	1040	1040	1300	1440	1360	900	1160	1160	1180
Platformate splitter investment	3	3	4	5	6	10	29	39	0	5	5	6
Hydrotreater investment	.	177	306	264	304	138	304	406	195	264	271	265
Hydrodesulphuriser LP investment	.	.	.	.	.	.	.	.	.	.	.	.
Hydrodesulphuriser MP investment	.	.	.	.	.	.	.	.	.	.	.	.
Hydrodesulphuriser HP investment	10	1160	2579	3292	4059	21	35	4093	47	112	2668	4122
Bitumen investment	.	.	6	4	.	.	.	1	.	.	.	.
Lubes investment	.	.	7	.	.	.	.	.	.	.	9	4
Hydrogen investment	8	55	138	163	238	10	28	243	83	123	265	368
Delayed coker investment	.	.	.	.	.	.	.	.	.	.	.	.
Alky investment	19	8	22	25	36	49	38	58	231	310	247	255
Isom o/t investment	.	.	.	.	.	.	5	.	.	.	.	.
Isom rec investment	3	8	2	5	6	35	50	38	932	1024	1135	1160
LPL isom investment	3	6	15	18	30	47	178	254	.	23	23	31
MTBE investment	29	35	31	33	31	37	39	27	61	63	57	55
Butamer investment	.	.	.	.	.	2	.	.	5	.	.	.
Sulphur investment	.	12	16	19	31	8	27	66	12	19	35	58
Tame investment	.	.	.	.	.	2	31	31	.	29	29	39
Residue Desulph investment	.	.	.	.	.	.	.	.	.	.	.	.
HP LCO dearom. investment	.	.	.	.	.	.	.	.	.	.	.	.
2 stage hydrogen. investment	.	.	.	.	9	.	.	24	.	.	.	67
HCCG hydrotreater investment	.	.	.	.	.	123	598	552	264	689	686	690
Cat cracker investment	.	.	.	.	.	.	4	30	13	46	44	32
Hydro resid con investment	6	23	47	64	58	12	.	.	.	.	.	29
Hydrocracker rec. investment	.	.	.	.	.	.	.	.	.	.	.	.
Hydrocracker o/t investment	8	17	55	70	111	18	44	135	10	37	85	140
Gofiner investment	5	9	23	34	65	10	72	260	15	33	66	57
LCCG Splitter inv	2	3	3	4	5	7	33	32	2	27	33	32
LCCG Merox extraction inv	.	.	.	.	.	.	59	49	.	74	69	78
FGDWL inv	.	.	.	.	.	.	.	.	.	.	.	.
Total	**1163**	**2707**	**4324**	**5051**	**6045**	**1845**	**3040**	**7774**	**2777**	**4043**	**6900**	**8676**
Other Investment MUS$												
External MTBE Plants	353	370	386	379	389	160	125	11	1775	1265	1176	1194
External Methanol Plant	482	492	491	490	491	408	389	328	1106	891	848	851
Hydrogen recovery	880	855	865	885	875	875	875	900	775	800	750	760
Offsite facilites for transfers	417	406	465	465	474	494	478	513	411	469	486	526
Total	**2131**	**2123**	**2206**	**2218**	**2229**	**1937**	**1867**	**1752**	**4067**	**3425**	**3260**	**3331**
Incremental Investment MUS$												
Total Internal Investment	.	1508	3193	3941	4934	753	1933	6727	1502	2852	5675	7501
Total External Investment	.	28	42	34	45	-266	-320	-496	2047	1322	1190	1210
Total additional Investment	**.**	**1536**	**3235**	**3975**	**4979**	**487**	**1612**	**6231**	**3549**	**4174**	**6865**	**8711**
Global CO2 Mtpa												
Crude CO2	.	0.9	1.9	2.3	2.9	1.5	4.2	7.9	-6.2	-1.6	1.1	2.1
Natural Gas CO2	.	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.4	1.5	1.0	0.9	0.9
Field Butane CO2	.	0.1	0.1	0.1	0.1	-0.6	-0.8	-1.1	4.7	3.0	2.7	2.8
Total	.	1.0	2.0	2.4	3.0	0.7	3.3	6.4	0.0	2.5	4.7	5.8
Incremental Operating costs M$ pa												
Maintenance, ops & OH	.	65	138	170	213	33	83	291	65	123	245	324
Transfer costs	.	1	5	2	-7	2	-2	-2	-36	-18	-9	-18
Energy cost (global)	.	49	96	115	145	26	149	292	49	149	251	302
Cetane additive	.	.	.	.	.	.	.	.	.	.	.	.
External maintenance, ops & OH	.	1	2	1	2	-11	-14	-21	88	57	51	52
Total additional operating cost M$ pa	**.**	**116**	**240**	**289**	**354**	**49**	**216**	**559**	**166**	**311**	**538**	**661**
Net Present Value M$	**.**	**2668**	**5574**	**6793**	**8427**	**966**	**3722**	**11685**	**5172**	**7209**	**12113**	**15154**
Net Present Value MEURO	**.**	**2426**	**5067**	**6176**	**7661**	**878**	**3383**	**10623**	**4701**	**6554**	**11012**	**13776**

STF-9 CN cases (excluding cases above 56 CN with one or more infeasible regions)

	1404	1405	1406
Investment in added process plant. MUS$			
Distiller investment		3	.
Vac Dist investment		0	1
Visbreaker investment		1	0
Reformer LP investment		5	14
Reformer HP investment		10	16
MCN Reformer upgrade	1000	1000	1080
Platformate splitter investment	.	6	16
Hydrotreater investment	.	210	345
Hydrodesulphuriser LP investment	.		.
Hydrodesulphuriser MP investment	.		.
Hydrodesulphuriser HP investment	.		.
Bitumen investment	.		6
Lubes investment	.	.	.
Hydrogen investment	.	593	845
Delayed coker investment	.	.	.
Alky investment	.	.	.
Isom o/t investment	.	.	.
Isom rec investment	.	54	161
LPL isom investment	.	44	124
MTBE investment	.	2	12
Butamer investment	.	.	.
Sulphur investment	.	27	50
Tame investment	.	.	.
Residue Desulph investment	.	.	.
HP LCO dearomatisation investment	.	.	.
2nd stage dearomatisation investment	.	2897	3580
HCCG hydrotreater investment	2	51	59
Cat cracker investment	.	.	.
Hydro resid con investment	.	.	.
Hydrocracker rec. investment	.	531	1273
Hydrocracker o/t investment	.	30	20
Gofiner investment	.	19	11
LCCG Splitter investment	.	8	8
LCCG Merox extraction investment	0	.	.
FGDWL investment	.	180	337
Solvent Deasphalter	.	.	.
Residue Gasifier	.	.	.
Power gen	.	.	.
Hydrogen from SG	.	.	.
Other Investment MUS$			
External MTBE Plants	911	876	879
External Methanol Plant	805	779	782
Hydrogen recovery	565	550	540
Offsite facilities for transfers	425	419	439
Total	**2706**	**2624**	**2639**
Incremental Investment MUS$			
Total Internal Investment	**.**	**4648**	**6945**
Total External Investment	**.**	**-61**	**-56**
Total additional Investment	**.**	**4587**	**6889**
Incremental Operating costs M$ pa			
Maintenance, ops & OH	.	201	300
Transfer costs	.	-20	-39
Energy cost (global)	.	386	568
Cetane additive	.	.	.
External maintenance, ops & OH	.	-3	-2
Total additional operating cost M$ pa	**.**	**565**	**826**
Net Present Value M$	**.**	**10096**	**14944**
Net Present Value MEUR	**.**	**9178**	**13585**

APPENDIX 6 EXPLANATORY NOTES

AO1 measures	The road fuel qualities required by EU legislation for Year 2000 and Year 2005 following the first Auto/Oil co-operative initiative aimed at developing rational cost-effective measures.
Antagonism	Is present when the effects of two different condition changes are bigger taken together than the sum of the effects taken individually.
ASTM D976	A procedure that uses the density and 50% boiling point temperature (2 parameters) to provide Cetane Indices of components used for calculating Cetane Index of blended diesel fuel.
Base case (09Y0)	The case against which all the condition changes investigated are compared and the delta effects (cost and CO_2 emissions) calculated. The first 2 digits uniquely refer to a gasoline case specification and the second 2 digits to a diesel specification.
DG-XVII 2020 study	The energy demand forecasts published by the European Commission's Directorate General XVII (energy). This comprised four scenarios with energy demands for years 2000, 2005, 2010, 2015 & 2020. One of these scenarios, Conventional Wisdom, was selected for the current study purposes.
EPEFE	The European Programme on Emissions, Fuels and Engine Technologies (EPEFE) published in 1995 established the relationship between fuel quality parameters and exhaust emissions of vehicles (pollutants: CO, NOx, HC, PM) for use in the AO1 air quality and cost-effectiveness evaluation process.
ETBE	See MTBE. Ethyl tertiary butyl ether ($C_6H_{14}0$) is a less volatile but otherwise similar gasoline component made by the same process but using ethanol (possibly bioethanol) instead of methanol.
GEUR	Billion (10^9) Euro
LHV	Lower heating value, a measure of the energy in a given mass of component or fuel.
LP model	A computer tool to calculate the economic optimum performance of a system under a given set of conditions.
MEUR	Million (10^6) Euro
MTBE	Methyl tertiary butyl ether ($C_5H_{12}0$), a non aromatic oxygenate high octane gasoline component made by combining imported methanol produced from natural gas either in small EU refinery units (50 kt/year, say) using isobutene produced in a refinery or in outside-EU world-scale units (400 kt/year, say) using isobutene made by processing oil/gas field butanes.

NPV	The Net Present Value combines once off costs (e.g. investment costs) and ongoing costs (e.g. annual energy costs), weighted to reflect the higher value of cash today compared with cash later in time to provide a measure of the total costs over a period of time (15 years in this study).
Parametrically	Changing one variable at a time.
PAH (di+)	Hydrocarbon molecule containing two and more aromatic rings.
pre-Kyoto	The EU energy demand scenario as forecast immediately prior to the 1997 UN Kyoto conference commitments made by the European Commission setting EU member states' 2010 CO_2 emissions ceilings.
Reformulation	Changing the composition of a road fuel as a consequence of improving environmental performance by imposing more severe specifications.
Synergy	Is present when the effects of two different condition changes are smaller taken together than the sum of the effects taken individually.
TAME	Tertiary amyl methyl ether, ($C_6H_{14}0$) similar to ETBE, made in refineries by reacting imported methanol with an olefinic C_5 naphtha component as produced from cat crackers.
Year 2000 specifications	The road fuels specifications proposed by the October 1997 European Council common position legislation to be implemented by 2000 and included in the EU Directive 98/70/EC, i.e. Gasoline: Sulphur content (mg/kg) 150 max, Aromatics content (% volume) 42 max, Olefins content (% volume) 18 max. Diesel: Sulphur content (mg/kg) 350 max, Cetane number (CN) 51 min, Density (kg/l) 0.845 max, Polyaromatic hydrocarbons (di+, % mass) 11 max.