Impact of product quality and demand evolution on EU refineries at the 2020 horizon

CO_2 emissions trend and mitigation options

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ABSTRACT

This report presents an integrated assessment of the impact of product quality and demand changes on EU refineries between 2000 and 2020 in terms of investment requirements, energy consumption and CO_2 emissions. It further explores the potential of various mitigating options available to EU refiners to curb the inevitable increase of their CO_2 emissions.

KEYWORDS

Demand, call-on-refineries, energy consumption, CO_2 emissions, capital investment, gasoil/gasoline ratio

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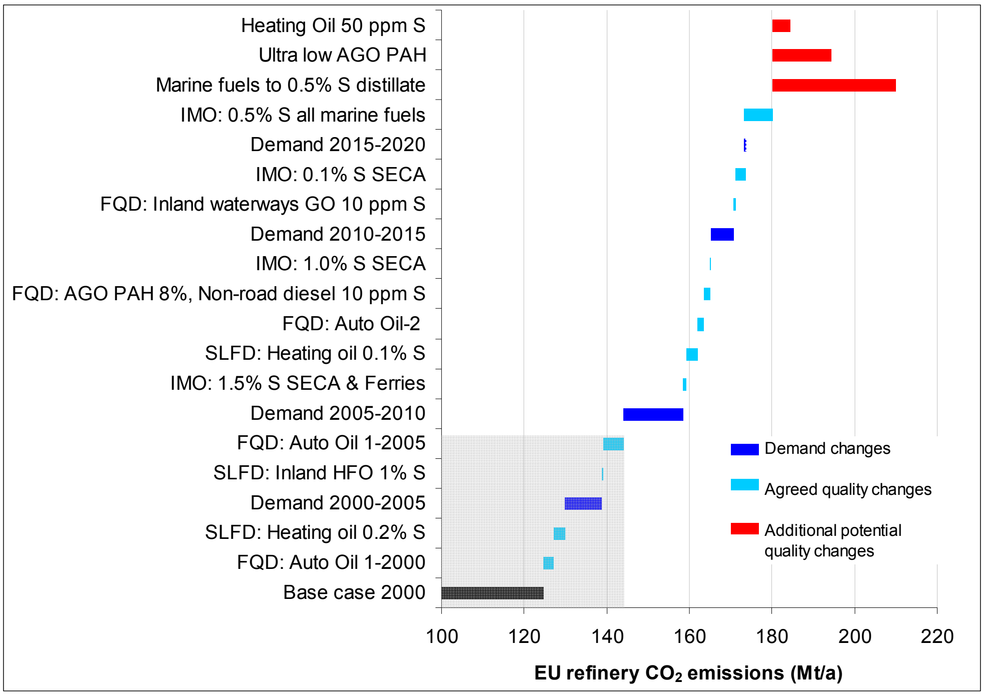
SUMMARY

Over the years oil refineries in the EU have developed and adapted to meet the evolving demand, in both qualitative and quantitative terms, while coping with an ever-changing supply of economically attractive crude oils. The combination of changes in product specifications, demand and crude supply requires constant adaptation of the refineries, taking all factors into account including the availability of dependable product import and export sources to balance production and demand under acceptable economic terms.

Starting from the premise that EU refineries continue to supply the EU market, this report sets out to assess their required investments between 2000 and 2020 and the impact on CO_2 emissions taking into account all regulations affecting refineries and their products that already have or will enter into force and the actual and anticipated supply and demand evolution during the period.

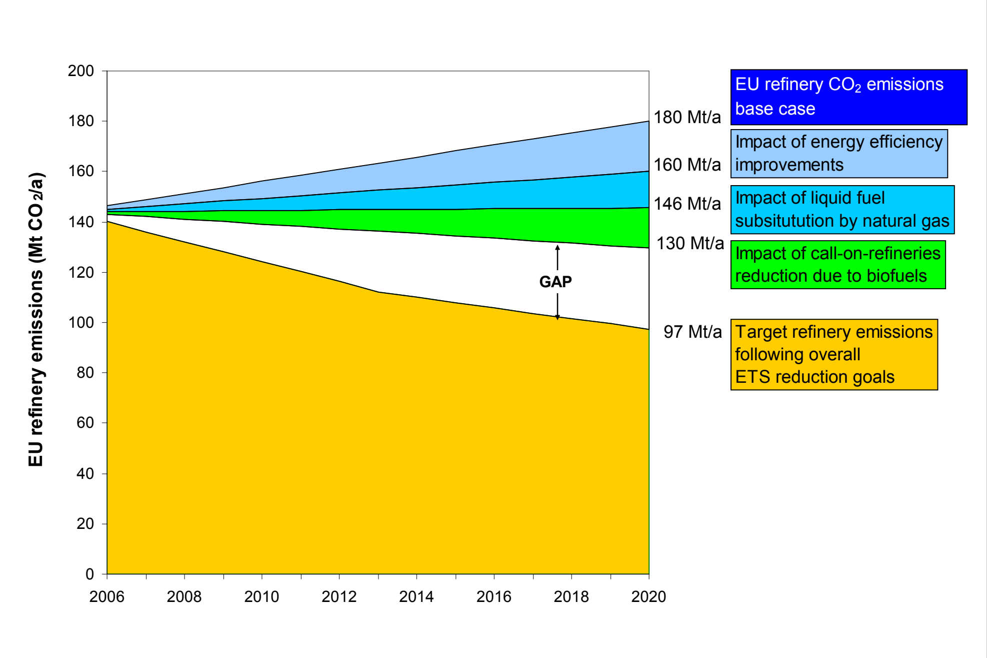
The combination of tougher product specifications, particularly the newly adopted international regulations on marine fuels, and of the relentless increase of the middle distillates over gasoline ratio leads to considerable investment needs, in the order of 61 G$ from 2005, 30 of which can be traced back to product quality changes and the balance to demand changes.

The resulting increase of processing intensity including the increasing need for hydrogen leads to a steady increase of CO_2 emissions. The figure below separately illustrates the impact of the various legislative measures as they come into force and of the demand changes, mostly characterised by the increasing middle distillates over gasoline ratio. Starting from the 2000 level, product quality and demand changes are respectively responsible for some 27 and 28 Mt/a additional CO_2 emissions.



In this context, meeting the EU policy goal of reducing the absolute level of CO_2 emissions from refineries is a tough challenge. The mitigating measures available to refiners are limited. Energy efficiency improvement, a constant theme for many years in refineries, still presents opportunities and these will undoubtedly be grasped especially in the current “expensive energy” environment. Replacing what liquid fuel is still burnt in refineries today by natural gas would reduce emissions at the refineries but the question has to be asked whether it would indeed result in global emission reductions. Similarly increased reliance on lighter crude oils might reduce EU refinery emissions but, inasmuch as these grades are in limited supply, would simply cause the opposite switch somewhere else in the world for no global curbing of emissions. CO_2 capture and storage raises many hopes and expectations but will not realistically make a meaningful contribution until the end of the period and into the third decade of this century.

Short of curtailing their level of activities, including reflecting the loss of call-on-refineries resulting from the introduction of biofuels, it is difficult to see how EU refineries will be able to achieve more than a stabilisation of their emissions between today and 2020.



1. CONTEXT AND BACKGROUND

Over the years oil refineries in the EU have developed and adapted to meet the evolving demand, in both qualitative and quantitative terms, while coping with an ever-changing supply of economically attractive crude oils.

The combination of changes in product specifications, demand and crude supply requires constant adaptation of the refineries, taking all factors into account including the availability of dependable product import and export sources to balance production and demand under acceptable economic terms.

In the last few years a number of CONCAWE studies have evaluated the impact of several discreet changes such as the road fuel specification changes associated with the Auto Oil programmes and sulphur reduction in marine fuels [1-5].

Although it is of interest to isolate the effects of individual parameters, it also has to be realised that these effects are not entirely independent of each other. There is a complex interaction between supply, demand, processing and other refinery constraints so that meeting the challenge of a combination of changes can require more or less effort than the sum of what would be required to meet each of them individually. This affects investment and operating costs as well as energy consumption and CO_2 emissions. Another aspect that is worth describing is the time line, as different regulations are due to come into force at different times when different levels of demand are expected.

This report sets out to describe the chronological evolution of the EU refining environment between 2000 and 2020 taking into account all known regulations that already have or will enter into force and the actual and anticipated supply and demand evolution during the period. It also considers key additional quality changes that have the potential for large impacts.

Reduction of CO_2 emissions is one of the major challenges for the coming years and the report also explores the options open the refiners to mitigate the impact of forthcoming changes on emissions from refineries.

2. SCOPE OF THE STUDY

Based on the results of a modelling study, this report develops an integrated view of the transformations required in EU refineries in order to cope with all product legislation and expected demand evolution to the 2020 horizon. It also explores the additional impact of other potential product quality changes that, although not firmly proposed or written into law at this point, are being discussed in various fora.

The year 2005 is used as the reference point for which the model is calibrated.

The momentous changes to road fuel quality implemented during the first 5 years of this decade as well as the relentless increase of diesel demand at the expense of gasoline have already forced large scale changes in EU refineries. This has also been illustrated by back casting the model to the year 2000 and the demand and product specifications applicable then[1].

The consequences for EU refineries are studied, with the CONCAWE refining model, in terms of new investments, total cost, energy consumption and CO_2 emissions. The key influence of the level of residue conversion, the fraction of sulphur removed from the crude and the required production ratio of middle distillate versus gasoline are analysed and discussed.

Having established the key impacts of demand and product quality changes over the period, we then examine the options available to EU refiners to mitigate these effects in terms of energy consumption and CO_2 emissions. In particular we look at the potential for energy efficiency improvements, refinery fuel switching, changes in crude oil diet and briefly consider the potential for CO_2 Capture and Storage (CCS) in refineries.

Equally momentous changes are afoot in the world of marine fuels and these have the potential to fundamentally affect refineries the world over and particularly in Europe. Although these changes are included in this report, this essential aspect of the future oil product scene will be discussed in more detail in a separate CONCAWE report to be published in due course.

[1] We considered that back casting beyond 2000 would take the model too far from its 2005 calibration point. Also from the point of view of CO_2 emissions, no reliable data is available before the beginning of the current decade.

3. MODELLING THE EU REFINING SYSTEM

This tool used for this study was the CONCAWE EU refining model. This model uses the linear programming technique to simulate the European refining system. It has a library of process units operating modes (yields, product properties, energy use and costs). EU-27 (+ Norway and Switzerland) is represented by 9 regions (see **Table 1**). In each region the actual refining capacity is aggregated, for each process unit, into a single notional refinery. The diversity of actual crude oils is represented by 6 model crudes. Other specific feedstocks can also be imported. The model can produce all usual refinery products in various quality grades. Exchanges of key components and finished products between regions are allowed at a cost. Economic data is included in the form of feedstock prices, product values, logistic costs, refinery investment and operating costs. Although ethylene crackers and aromatics production plants belong to the petrochemical rather than refining industry, olefins and aromatics production is included in the model so that the interactions between the two sectors, which are crucial to the understanding and dynamics of the lighter end of the barrel (gasoline, naphtha, LPG), are represented.

Table 1 The 9-regions of the CONCAWE EU refining model (EU-27+2)

Region	Countries [(1)]	Total primary capacity		
		kbbl/sd	Mt/a [(2)]	% of total
Baltic	Denmark, Finland, Norway, Sweden, *Estonia, Latvia,* Lithuania	1455	67	9%
Benelux	Belgium, Netherlands, *Luxembourg*	2144	99	13%
Germany	Germany	2508	115	15%
Central Europe	Austria, Switzerland, Czech, Hungary, Poland, Slovakia	1279	59	8%
UK & Ireland	United Kingdom, Ireland	1976	91	12%
France	France	2070	95	13%
Iberia	Spain, Portugal	1604	74	10%
Mediterranean	Italy, Greece, Slovenia, *Malta, Cyprus*	2475	114	15%
South East Europe	Bulgaria, Romania	781	36	5%
Total		16293	749	

[(1)] Countries in *italic* have no refineries

[(2)] Indicative number based on a notional 340 operating days per year

Given a set of premises and constraints (product demands, crude and feedstocks availability, plant capacities and economic data), the model proposes an “optimised” feasible solution on the basis of an economic objective function (maximum profit calculated as product value minus cost of crudes and feedstocks, minus operating costs minus financial burden from investments). The model obviously respects the total mass balance but also the elemental balances for carbon hydrogen and sulphur. This ensures amongst others that hydrogen deemed to be added to streams in the processes is actually accounted for in the final products. In this way the model can reliably estimate the impact of changes in terms of CO_2 emissions from both refinery sites and the whole of the petroleum products sector i.e. including changes in the carbon content of fuels. In the same way the sulphur balance allows tracking the fate of the sulphur in the crudes.

Because specification changes also lead to changes in calorific value we consider that demand for fuel products is based on calorific value rather than mass and therefore adjust the mass demand accordingly in each case.

The model was calibrated with real data from 2005. The calibration included tuning of the “energy efficiency” of process plants to match actual overall energy consumption data and small adjustments to the actual plant capacities in order to ensure that the base case is feasible and not over-constrained. This was then back-casted to the 2000 demand for which the “existing capacities” were adjusted.

All cases were then run as independent pathways to the future, always starting from the 2000 base case and adding additional product quality constraints and demand requirements one by one. Comparison of future scenarios with the 2000 base case established the need for additional plant capacities, the total cost to refiners of meeting the demand as well as the impact on energy consumption and CO_2 emissions of the refineries.

This approach assumes perfect foresight into the developments under consideration and therefore perfect synergy between the different requirements in order to optimise investments for each combination of constraints. Accordingly, when migrating from one case to the next, we did not take into account any investment that may be required in one case and not used by the model in the next, under the assumption that such investment would not actually be made. This may be seen as optimistic but is justified by the fact that, with the exception of some “step-out” cases at the end of the period, we have been looking at provisions that are either already known and planned for today or have been the subject of firm proposals.

As a rule the model was required to produce the stipulated demand from a given crude slate. Availability of other feedstocks, including natural gas either for hydrogen production or as fuel, was also kept constant. The main flexibilities were crude allocation to each region, intermediate and finished product exchanges and mainly investment in new process units (i.e. beyond the 2005 installed capacities). In line with considerations in *section 4.3* the crude diet was kept the same in all cases (45% light low sulphur, 55% heavy high sulphur) only one crude (Heavy Middle East) being allowed to vary to balance the requirements (e.g. for refinery energy consumption). Changes in e.g. crude slate or availability of natural gas were studied through special sensitivity cases, thus clearly isolating the impact of different factors.

When running the model in this manner, the impact of absolute prices on the model response are somewhat limited as the model runs more in a “cost minimisation” than “profit maximisation” mode. This methodology also dispenses with the need to engage in price forecasts which are inevitably speculative and subject to criticism. Nevertheless a set of prices must be used. In this case we have used the average 2007 prices for North West Europe in all cases for both crude and products as detailed in **Appendix 1**.

All operating and investment cost figures in this report are meant to be in constant 2008 US$.

In this report, we concentrate on the global EU analysis. Although the model gives a full account of the outcome for each region, it is not possible to draw meaningful conclusions from regional changes between cases. This is because the model optimises the whole of Europe rather than each region separately. From one case to the other the regional crude diet as well as the level of component transfers between regions can vary significantly effectively moving the “goal post” in each individual case.

4. EVOLUTION OF OIL PRODUCTS SUPPLY DEMAND AND QUALITY IN EUROPE BETWEEN 2000 AND 2020

In the last decade the oil product market in Europe has undergone very significant changes. This will continue through the coming decade and towards the 2020 time horizon considered in this study. The changes stem both from the evolution of demand, particularly with that of road fuels but also the relentless increase in the proportion of diesel and jet fuel, and from product quality changes brought about chiefly by environmental legislation across the spectrum of fuel grades.

In this section we first consider the timeline of product quality changes brought about by new legislation. We then consider the evolution of demand using forecasts essentially based on results of consultancy firm Wood Mackenzie's (WM) "Global Outlook" as published in 2007. This excludes petrochemicals (i.e. light olefins and aromatics) for which data was obtained from CEFIC[2]. Finally we briefly discuss the EU crude supply situation and its likely evolution over the period.

4.1. PRODUCT QUALITY LEGISLATION

Pressure on the quality of petroleum fuels has been relentless for many years. This has affected all fuels although road fuels have arguably been the subject of most of the attention over the past say 20 years. This is set to continue in the foreseeable future with a number of already legislated measures due to enter into force although, at this stage, no major further changes are foreseen for road fuels. The focus is now to some extent moving towards marine fuels.

Table 2 shows the chronological sequence of specification changes of various fuel products from the mid 90s through to 2020 as implied by agreed or proposed legislation.

"Fuels Quality Directive" (FQD)

The various dispositions of Directive 98/70/EC promulgated as a result of the first Auto-Oil programme came into force between 2000 and 2005 affecting road fuels. The second Auto-Oil programme resulted in a first revision, including the introduction of sulphur-free road fuels (<10 ppm). A further revision currently under discussion introduces further limits on road fuels, non-road mobile machinery fuels and inland waterways fuels.

"Sulphur in Liquid Fuels Directive" (SLFD)

Directive 1999/32/EC affects heating oil, industrial gasoils and inland heavy fuel oils.

Marine fuels legislation (IMO)

The sulphur content of marine fuels is regulated on a worldwide basis through the International Maritime Organisation (IMO). An agreement under the International Convention for the Prevention of Pollution from Ships (MARPOL), known as MARPOL Annex VI, introduced a global sulphur content cap of 4.5% m/m as per May 2005. It also introduced the concept of Sulphur Emission Control Areas (SECA) which are special sea areas where ship sulphur emissions are consistent with a fuel having a maximum sulphur content of 1.5% m/m. The Baltic and North Sea have

[2] European Council of Chemical Industry Federations

been designated as SECAs. Following its ratification in 2005, MARPOL Annex VI came into force as of May 2006 for the Baltic Sea and November 2007 for the North Sea. A revision process of that legislation was initiated by IMO's Marine Environment Protection Committee in July 2005.

In addition, the EU adopted Directive 2005/33/EC which extends the 1.5% m/m sulphur limit to "passenger ships on a regular service to or from an EU port" (further referred to as "ferries") and came into effect in August 2006. The Directive includes a review clause whereby the possibility can be envisaged of extension of the sulphur limit to all EU waters and its further reduction.

IMO's Marine Environment Protection Committee (MPEC) recently adopted a proposal to decrease the maximum sulphur content in SECAs to 1.0% by 2010 and 0.1% by 2015 and, parallel to decrease the global marine fuels sulphur cap to 3.5% by 2010 and down to 0.5% by 2020 or 2025 at the latest (subject to a review in 2018). It is not clear at this stage whether the EU would enforce the SECA reduction schedule also to "ferries".

It has to be noted that, outside the SECAs, the IMO cap reduction proposal and the Directive do not directly mandate the indicated fuel sulphur content but rather emissions consistent with these sulphur contents. This therefore leaves open the possibility to use sea water scrubbers, a number of which have been developed to full scale demonstration stage. This study, however, examines the fuel desulphurisation option.

The reduction of the marine fuels global sulphur cap to 4.5% (2005) and 3.5% (2010) were not modelled as separate cases as our model did not experience these limits as constraints. In real life, a limited number of refineries and fuel blenders may be affected in Europe but the main impact is likely to be in areas outside Europe where marine fuel sulphur contents tend to be higher (e.g. in the Middle East).

No significant quality changes are foreseen for other products. This includes jet fuel. the maximum sulphur content of which is assume to remain at 0.3% m/m over the entire period. **Appendix 2** shows the detail of the specifications and corresponding quality targets used in the model, the difference representing the usual level of operating quality margins that refineries have to use in order to ensure on-spec products.

Table 2 Chronology of specification changes

Year	Product(s)	Legislation	
2000	Gasoline / Diesel	Directive 98/70/EC on fuels quality: Auto Oil 1 phase 1	150/350 ppm S in gasoline/diesel + other specs
2000	IGO/Heating oil	Directive 1999/32/EC on sulphur in liquid fuels	Heating oil 0.2% S
2003	HFO	Directive 1999/32/EC on sulphur in liquid fuels	Inland HFO 1% 1S
2005	Gasoline / Diesel	Directive 98/70/EC on fuels quality: Auto Oil 1 phase 2	50 ppm S in gasoline/diesel + 35% aromatics in gasoline
2006-7	Marine fuels	Marpol Annex VI, Directive 2005/33/EC on the sulphur content of marine fuels: sulphur restrictions in Baltic and North Sea SECAs and for EU ferries	1.5% S in marine fuel for SECA & Ferries
2008	IGO/Heating oil	Directive 1999/32/EC on sulphur in liquid fuels	Heating oil 0.1% S
2009	Gasoline / Diesel	Directive 98/70/EC on fuels quality: Auto Oil 2	10 ppm S in gasoline/diesel
2009	Gasoline / Diesel	Fuels Quality Directive proposal: Non-road diesel specification and diesel PAH limit	8% m/m PAH in road diesel 10 ppm S in non-road diesel
2010	Marine fuels	IMO: sulphur restriction in SECAs, extended to EU ferries by Directive 2005/33/EC on the sulphur content of marine fuels	1.0% S in marine fuel for SECAs
2011	Marine diesel	Fuels Quality Directive proposal: Inland waterways diesel	10 ppm S in gasoil for inland waterways
2015	Marine fuels	IMO: sulphur restriction in SECAs, extended to EU ferries by Directive 2005/33/EC on the sulphur content of marine fuels	0.1% S in marine fuel for SECAs
2020	Marine fuels	IMO: Global sulphur cap	0.5% S in all marine fuels
Step-out cases			
	Marine fuels	*Substitution of all marine fuels by distillates at <0.5% sulphur*	
	Diesel	*Reduction of PAH to < 2% m/m*	
	Heating oil	*Heating oil sulphur reduction to <50 ppm*	

Table 2 also includes the assumptions made for three "step-out" cases representing possible, albeit not legislated or formally proposed, potential future changes:

- All residual marine fuel replaced by distillate (at the sulphur level prevailing in 2020 i.e. 0.1% in SECAs and 0.5% elsewhere),
- Large reduction of road diesel PAH content (down to 2% m/m),
- Reduction of heating oil sulphur content to 50 ppm.

Appendix 3 shows the assumed quality of the marine "distillate" that would substitute residual fuel. This is consistent with the grade known as DMB.

4.2. PRODUCT DEMAND AND CALL ON REFINERIES

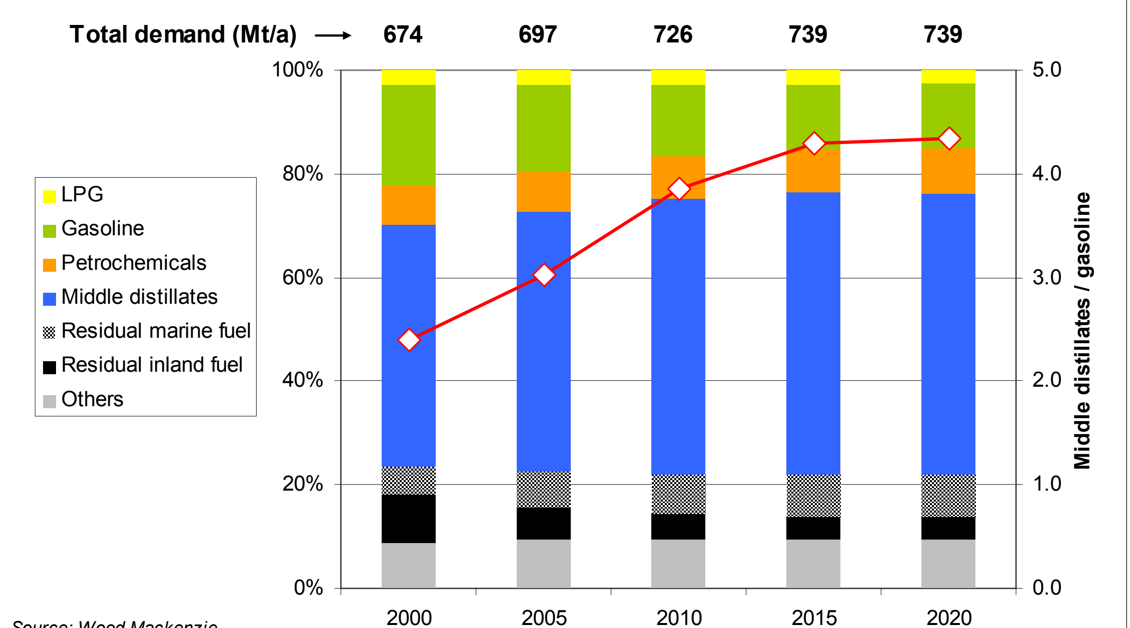
For many years European petroleum product demand has been shaped by three main trends:

- Slow rate of growth of total demand,
- Gradual erosion of demand for heavy fuels and concomitant development of markets for light products,
- Within the light products market, a relentless increase of demand for "middle distillates" particularly automotive diesel and jet fuel, and a slow erosion of motor gasoline demand.

These trends are largely expected to continue as illustrated in **Figure 1** (a more comprehensive table is also included in **Appendix 4**). Total demand in EU-27+2, still sustained by growth in the new Member States in the early years, is expected to flatten from 2015. The gradual erosion of heavy fuel demand is, however, slowing down particularly towards the end of the period as the reduction of inland fuel demand is fully compensated by growth of the marine market.

The figure also shows the historic and predicted steady increase of the ratio between middle distillates and gasoline demand until at least 2015. The WM data suggests levelling out of this ratio thereafter as the trend towards ever more diesel cars slows down and eventually reverses. Many parameters will play a part in determining the actual outcome. As far as cars are concerned this implies success of gasoline vehicle fuel economy improvement technologies while after treatment devices penalise diesel vehicles. Other crucial developments will be the rate of development of road haulage that represents a large proportion of total diesel demand. The rate of growth of air transport will of course be crucial in determining jet fuel demand. The WM figures are considered optimistic by some i.e. forecasting too low ratios towards the end of the period.

Figure 1 EU petroleum product demand evolution 2000-2020
("Petrochemicals" includes light olefins and aromatics)



Source: Wood Mackenzie

Evaluation of the impact of marine fuel legislation requires estimating demand volumes at a more detailed level than available from WM. This includes demand in SECAs as well as additional demand for "ferries" (as per Directive 2005/33/EC see *section 4.1* above).

Demand in the North and Baltic seas SECAs was originally estimated on the basis of internal information. The figures were found to be in reasonable agreement with those used by IIASA for their integrated air quality assessment model RAINS. Estimation of the additional demand represented by "ferries" that operate within European waters but outside SECAs proved more difficult not least because there does not appear to be full agreement as to what vessels are covered by the definition given in the Directive. The BMT report [6] indicates that "RoRo" (Roll-on/Roll-off) and cruise ships represent about 30% of total fuel consumption in

Europe. Based on a recent study of shipping in the Mediterranean by ENTEC for CONCAWE, “passenger” ships represent roughly 50% of the available engine power in the overall RoRo segment, which include both cargo only and passenger ships. We therefore assumed that the vessels meant to be covered by the Directive account for 15% (50%*30%) of total EU demand. In order to avoid double counting this percentage was only taken into account for areas not affected by the SECA regulation. The resulting demand for the various segments is shown in **Table 3**.

Table 3 Residual marine fuel demand for various segments

Mt/a	2000	2005	2010	2015	2020
Total	36.3	46.5	56.0	60.3	62.1
SECAs	9.6	12.5	15.9	17.2	17.8
% of total	*26%*	*27%*	*28%*	*29%*	*29%*
non SECA ferries			5.9	6.3	6.5
SECAs + Ferries	9.6	12.5	21.8	23.5	24.3
% of total	*26%*	*27%*	*39%*	*39%*	*39%*

Having established the European market demand, one has to estimate the actual call on EU refineries i.e. make an assumption on the amount of trade (import/export) that is likely to take place. We have deliberately kept these figures constant in order to keep consistency between cases i.e. compare cases where EU refineries have to bear the cost of adaptation to changes. As shown in **Appendix 4** we have assumed 22 Mt/a of gasoline exports, 20 Mt/a of gasoil and 15 Mt/a of jet fuel imports. These distillate figures are consistent with actual figures from the last few years. Gasoline exports have been higher in the last 2-3 years but there are many signs that this market is shrinking and we thought prudent to use a somewhat lower figure.

If data on marine fuel consumption is rather scarce, information on the origin of these fuels is even more difficult to obtain. In this study, we have assumed that bunkering outside the EU by EU-bound ships is roughly balanced with ships doing the reverse i.e. that EU refineries are supplying the equivalent of the whole of the EU demand.

4.3. EU CRUDE OIL SUPPLY

Crude oil is a worldwide commodity. Although most grades are traded on a wide geographical basis, consuming regions tend, for logistic and geopolitical reasons, to have preferred supply sources. The favourable geographic location of Europe in relation to light and sweet crude producing regions (North Sea, North and West Africa) has resulted in a fairly light crude diet in the past two to three decades.

North Sea: This is indigenous production for which Western Europe has a clear logistic advantage. Although some North Sea crude finds its way to the US, the bulk is consumed in Europe. These crudes are mostly light and low sulphur.

Africa: North African crudes (Algeria, Libya, Egypt) are naturally part of Southern Europe's "captive" production. West African crudes can profitably go either to North America or to Europe and the market is divided between these two destinations. There is a wide range of quality amongst these crudes from very light and low sulphur Algerian grades to fairly heavy and sour Egyptians.

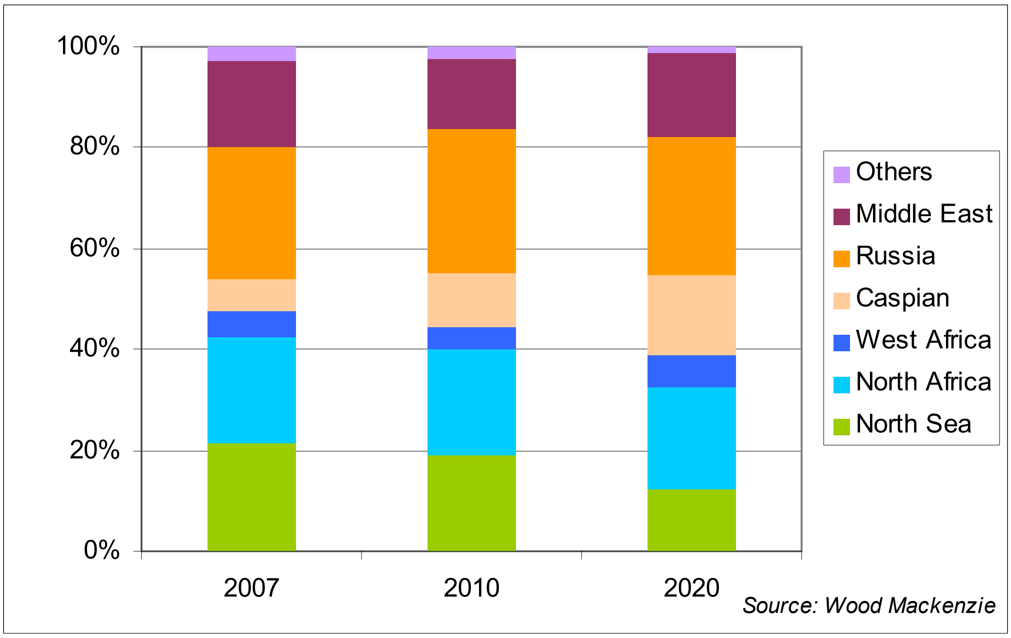
Middle East: The region is an important supplier, mainly of heavy, high-sulphur grades, typically used for the manufacture of bitumen or base oils for lubricant production and by refineries with appropriate desulphurisation and residue conversion facilities.

FSU: Russia is a steady and growing supplier of medium quality crude to Europe, partly through an extensive inland pipeline system extending to most former East European block countries. The Caspian basin is poised to become a major producer of light sweet crudes with Europe as a preferred customer because of favourable logistics.

EU-27+2 consumed about 715 Mt of crude oil and feedstocks in 2005 (695 Mt in 2000). This is set to grow to 765 Mt in 2020. Although it is considered that supply should be adequate within this timeframe, the sources of supply for Europe will change. North Sea production will decline but other regions such as West Africa and the Caspian basin will take over. These changes in the origin of the crude oil will not significantly affect the average quality and it should be possible to maintain the current proportion of around 45% of sweet (i.e. low sulphur) crudes over the next decade. In the long term though, the quality of world reserves heralds an inevitable trend towards heavier and more sulphurous crudes.

The current and projected European crude supply is shown **Figure 2**.

Figure 2 Current and projected crude slate in Europe



Using our model crudes this diet was modelled as shown in **Table 4**. During the model calibration exercise it appeared that matching the average sulphur content of the combined crude diet with actual figures resulted in too low a proportion of residual material. This was corrected by "heavying" the diet through addition of 20 Mt/a of Brent vacuum residue.

Table 4 Model crude diet

Mt/a	2000	2005	2010	2015	2020
Brent*	228.1	238.2	254.7	265.4	265.7
Nigerian	58.7	58.7	58.7	58.7	58.7
Algerian condensate	1.7	1.7	1.7	1.7	1.7
Iranian light	143.0	143.0	143.0	143.0	143.0
Urals	139.0	128.9	112.4	101.7	101.4
Kuwait	71.3	94.7	Balance as required		

* Plus 20 Mt/a vacuum residue of same origin

4.4. OTHER FEEDSTOCKS

In addition to crude oil a number of additional feed streams and blending components were provided and essentially kept constant throughout the study except in specific sensitivity cases.

- 3 Mt/a methane (natural gas) for either hydrogen production or fuel
- 2.5 Mt/a ethane as steam cracker feedstock
- Enough ethanol to feed the existing refinery-based ETBE manufacturing capacity (about 1 Mt/a)
- 10 Mt/a each of road quality diesel and heating oil (imports)
- 15 Mt/a jet fuel
- 1.7 Mt/a ETBE

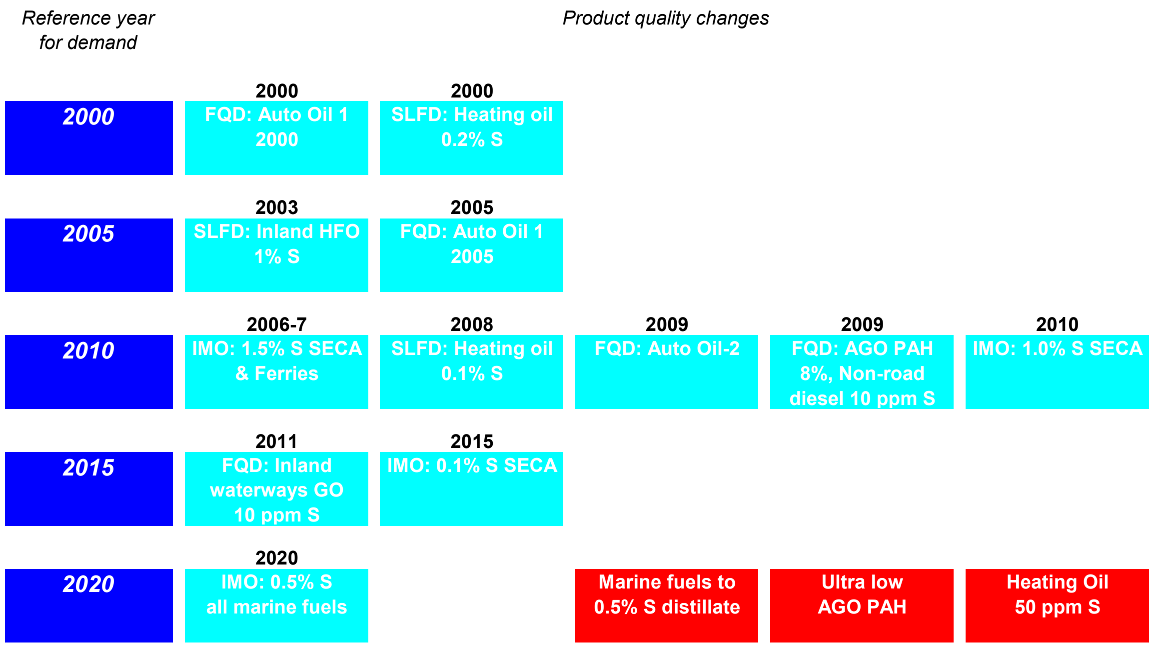
Note that naphtha imports were gradually phased out to zero by 2015.

5. STUDY CASES

In a first set of cases we endeavoured to represent the evolution of EU refineries over the years as new legislation comes into force and as demand evolves. The total period between 2000 and 2020 was divided into 5-year periods in which demand was kept constant and the quality changes introduced in chronological order. The “demand” step at the beginning of each period included all quality changes introduced in the previous one. The three quality “step-out” cases mentioned in *section 4.1* were explored separately using the 2020 demand as well as in a combined case where possible synergies were taken into account.

As mentioned in *section 3* the refinery configuration in place in 2005 was used as starting point in every case i.e. assuming perfect foresight and therefore optimum combination of investment for each end point. In this first set, the refineries' performance in energy terms was kept constant i.e. no improvement in energy efficiency was assumed compared to 2005 for which the model was calibrated). The set of cases is shown graphically in **Figure 3**.

Figure 3 Time-bound cases



The same set was subsequently rerun, now assuming steady efficiency improvements (see further details in *section 6*). Also using the 2020 demand, additional sensitivity cases were included to investigate the impact of:

- Reduction of the liquid refinery fuel maximum sulphur content to 0.2%,
- Refinery liquid fuel substitution by imported natural gas,
- Changing crude diet,
- The price of CO_2.

Finally a “low demand” case was included in relation to biofuels introduction. More details on all these sensitivities are discussed in *section 6*.

6. KEY IMPACTS FROM 2000 TO 2020

As indicated in *section 3*, our modelling includes refineries as such and petrochemical plants producing light olefins (steam crackers) and aromatics. In this section and the following, the term “refinery” is used to describe the whole system. The specific share of petrochemicals is discussed in *section 6.5*.

In all cases the model was forced to produce the “call on refineries” discussed in *section 4.2* for the time-period under consideration. **Table 5** shows the evolution of total production and crude diet over the 5-year periods as well as the impact of the three quality step-out cases both separately and combined.

The fraction of light products increases only marginally except where the switch to distillate marine fuels causes a very large change, effectively eliminating more than half of the residual fuel production. In accordance to the WM forecast the crude diet remains fairly constant in terms of quality although the average crude sulphur content increases somewhat as a result of our choice of a heavy high sulphur Middle Eastern grade as balancing crude.

The most notable change in terms of demand is the relentless increase of the middle distillate to gasoline ratio, at least until 2015. This makes it increasingly difficult for EU refineries to produce the required product slate and requires massive investments in new plants as well as additional processing energy, additional hydrogen production and ultimately additional CO_2 emissions.

Table 5 Refinery production and crude diet

		Timeline					Potential product quality changes			
		2000	2005	2010	2015	2020	Marine fuel to 0.5% S distillate	Ultra low diesel fuel PAH	Heating oil to 50 ppm S	All three changes
Crude diet										
API gravity		35.3	35.2	35.2	35.1	35.1	35.1	35.1	35.1	35.1
Proportion of LS crude		45%	45%	45%	45%	45%	45%	45%	45%	45%
Sulphur content	% m/m	1.00%	1.04%	1.10%	1.14%	1.14%	1.14%	1.14%	1.14%	1.15%
Atm. Residue yield	% m/m	42.7%	42.8%	42.9%	43.0%	42.9%	43.0%	43.0%	42.9%	43.0%
Total production	Mt/a	672	689	716	729	728	725	727	728	724
Fraction of light products[(1)]		80.2%	81.7%	82.1%	82.2%	82.2%	90.5%	82.2%	82.2%	90.5%
Production ratios										
Diesel / gasoline		0.9	1.2	1.6	1.9	1.9	1.9	1.9	1.9	1.9
Gasoil / gasoline		1.6	2.0	2.5	2.7	2.6	3.2	2.6	2.6	3.1
Middle distillates / gasoline		1.8	2.3	2.9	3.2	3.2	3.7	3.2	3.2	3.7

(1) Gasoils and lighter, also including petrochemicals

6.1. ADAPTATION OF EU REFINERIES: INVESTMENT IN NEW PLANTS

If EU refineries are to continue supplying the EU market as they do today, they will need to undergo major adaptation. As explained before, because we constrain the model with fixed demand and minimum flexibility on crude and feedstock supplies, the only available response is investment according to the lowest overall cost (capital charge and operating costs).

Figures 4a/b illustrate the scale of investment required. **Figure 4a** details the contribution of each quality or demand change over the whole time period whereas **Figure 4b** separately shows the cumulative investment requirement related to demand and product quality between 2005 and 2020. “Potential PQ changes” represents the case where all three step-out cases have been combined.

The industry has already heavily invested since the beginning of the decade, essentially to meet Auto-Oil specifications for road transport and desulphurise heating oil. Our backcasting to 2000 indicates about 15 G$ investment to meet changing demand between 2000 and 2005 but this is, as indicated earlier, assuming a constant level of import/export. Some of this investment has undoubtedly occurred in reality but the demand change and particularly the increase in the middle distillate to gasoline ratio has been partially met by increased trading activities (gasoline export and gasoil imports to/from outside the EU) thereby lowering the investment burden. Looking forward, the investment requirement between 2005 and 2020 is about 61 G$, 30 of which would go into meeting forthcoming legislation and 31 into adapting to changing demand. Further legislation, particularly on marine fuels and diesel fuel PAH content, could nearly double that number.

Figure 4a Time series of investment required in EU refineries

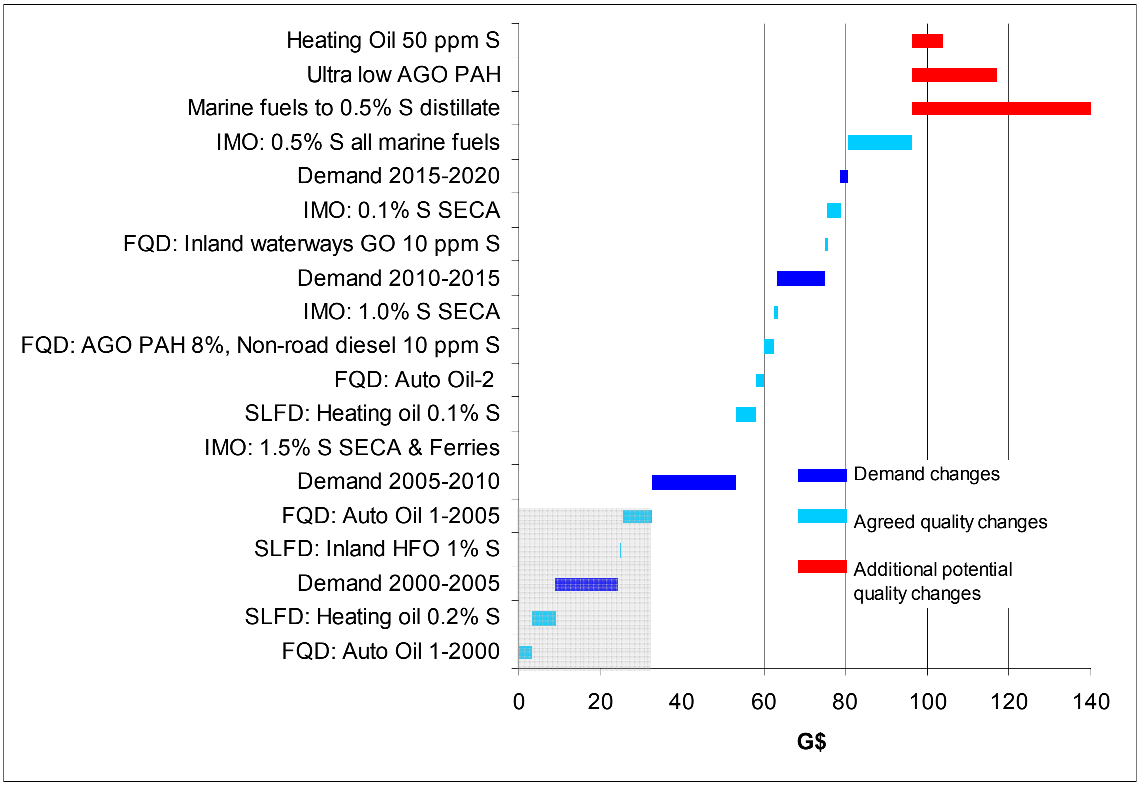


Figure 4b Cumulative investment required in EU refineries by 2020

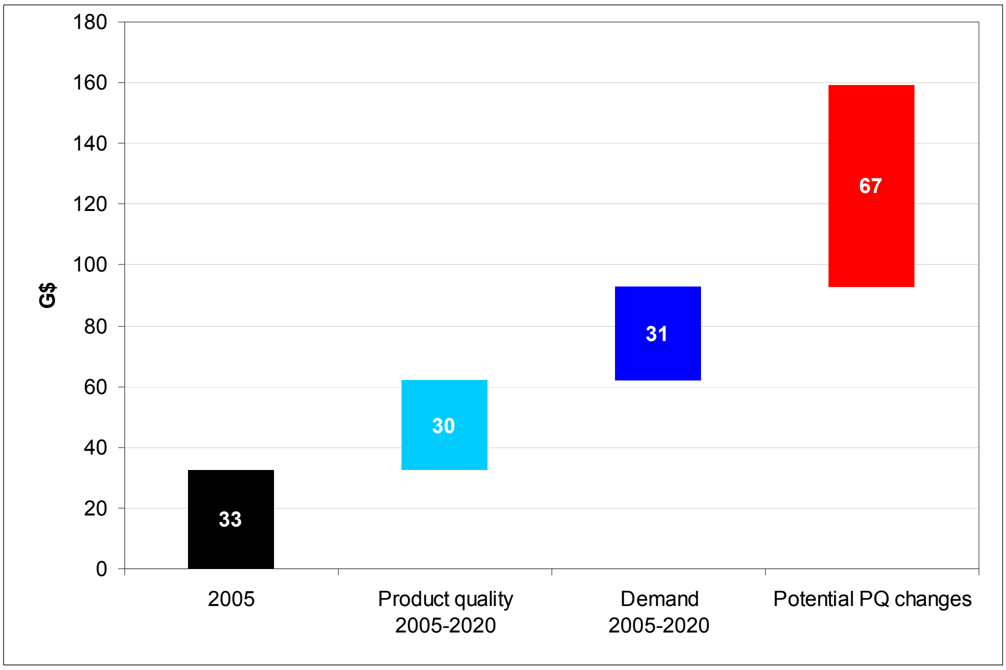


Table 6 shows the type and capacities of the new plants that will be required as well as the actual utilisation of all plants. For the time series from 2000 to 2020 the deemed 2000 capacities are used as reference. For the quality step-out case the reference is the 2020 end point.

New capacity and utilisation do not always follow the same pattern e.g. in some cases additional capacity is required whereas utilisation decreases. This is because the figures are cumulative across the 9 modelling regions. Some regions may require additional capacity (and utilisation) whereas others may see utilisation of existing capacity decrease.

Crude distillation increases marginally (in line with total demand increase) but the main changes are seen in residue conversion processes.

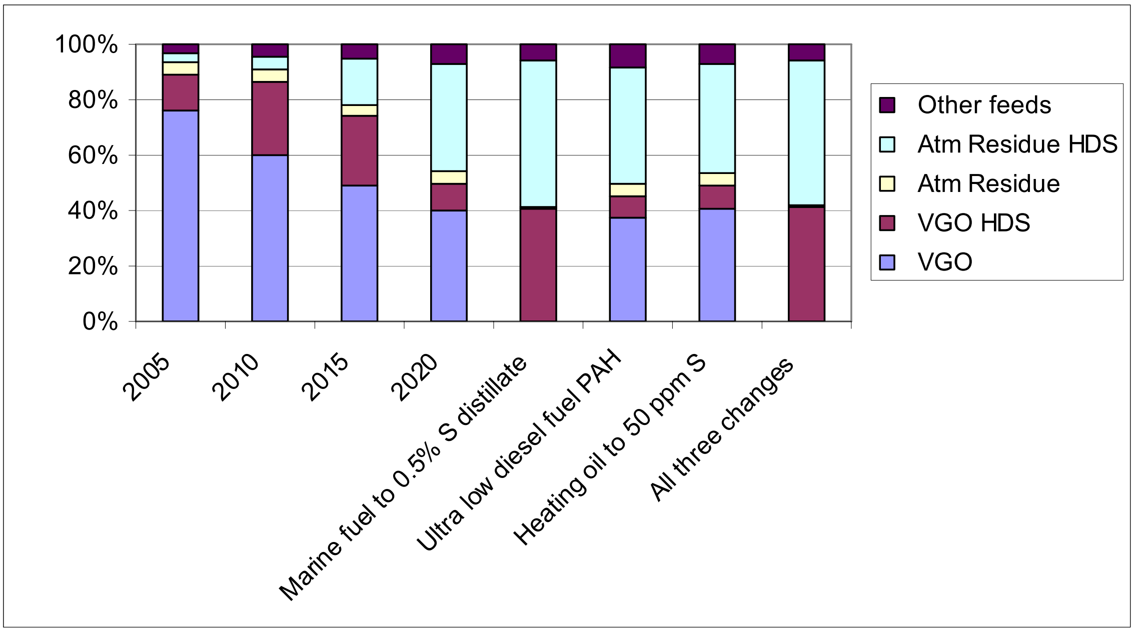
Utilisation of FCCs is somewhat eroded although not as much as one could have imagined in a situation where the model tries to minimise gasoline production. The mechanism favoured by the model is to utilise existing FCC capacity as far as possible by pretreating the distillate feedstocks in mild hydrocrackers and using large amounts of desulphurised atmospheric residues (**Figure 5**). At the same time virgin vacuum gasoil is made available for additional hydrocrackers producing the much needed middle distillates. Vacuum distillation capacity still needs to increase to produce additional hydrocracking feedstock. The FCC mode of operation also shifts from the traditional high severity / high gasoline mode to lower severity yielding more middle distillates.

Table 6 Capacity utilisation and additional process unit capacity

	Timeline					Potential product quality changes			
	2000	2005	2010	2015	2020	Marine fuel to 0.5% S distillate	Ultra low diesel fuel PAH	Heating oil to 50 ppm S	All three changes
Existing and new process unit throughput (Mt/a)									
Crude atmospheric distillation	642	665	700	721	723	728	725	723	731
Vacuum distillation	250	259	272	261	211	243	207	211	246
Visbreaking	73	82	87	82	65	61	60	65	62
Coking	11	12	12	11	11	20	11	11	21
FCC	123	123	107	102	108	95	101	108	94
Hydrocracking	45	58	94	101	77	134	78	76	136
Resid desulphurisation/conversion	8	10	12	28	79	91	82	79	89
Reformate / FCC gasoline splitting	12	65	50	48	47	35	45	48	36
Aromatics extraction	8	5	7	9	12	12	12	12	12
Isomerisation / Alkylation	15	18	15	14	13	15	14	13	16
PP splitting	4	4	4	4	4	4	4	4	4
Middle distillate hydrotreating	70	153	158	211	222	193	224	268	238
Gasoil dearomatisation	0	0	0	0	0	0	117	0	100
Hydrogen (in kt/a of H_2)	86	422	693	974	1283	1951	1797	1374	2418
Steam cracker	61	68	71	72	74	77	74	74	77
Additional process units capacity (Mt/a)		Relative to base 2000				Relative to 2020 end point			
Crude atmospheric distillation		24	57	77	79	8	3	1	14
Vacuum distillation		9	22	11	7	5	-1	0	7
Visbreaking		9	15	10	5	2	-4	0	2
Coking		0	0	0	0	9	0	0	10
FCC		0	0	0	0	1	-1	0	0
Hydrocracking		16	60	70	35	78	5	0	81
Resid desulphurisation/conversion		2	3	19	71	12	3	0	10
Reformate / FCC gasoline splitting		53	38	36	35	-12	-2	1	-12
Aromatics extraction		1	1	2	4	0	0	0	0
Isomerisation / Alkylation		2	1	1	1	1	0	0	2
PP splitting		0	1	1	1	1	0	0	0
Middle distillate hydrotreating		83	89	142	154	-28	0	45	14
Gasoil dearomatisation		0	0	0	0	0	117	0	100
Hydrogen (in kt/a of H_2)		336	606	887	1196	668	514	92	1136
Steam cracker		7	11	11	14	3	0	0	3
		Relative to base 2000				Relative to 2020 end point			
Capital expenditure G$		36.0	56.6	78.5	96.1	43.9	20.7	7.6	66.6
Total annual cost(1) G$/a		9.2	14.6	20.1	24.6	12.2	5.5	1.9	18.3

(1) Including capital charge, excluding margin effects

Figure 5 FCC feed composition



The 2020 end point is quite different from the 2015 case because of the desulphurisation of marine fuels to 0.5%. This requires a large increase of residue desulphurisation capacity, partly compensated by a lower need for new hydrocrackers (residue desulphurisation also provides some conversion).

Replacing residual marine fuels, even already desulphurised to 0.5%, by distillates would still require a massive addition of hydrocracking capacity while distillate desulphurisation capacity is reduced as a result. This is matched by a large increase of the installed hydrogen production capacity as, in fine, the around 1% higher hydrogen content of the distillate material which represents a total of around 550,000 t/a of hydrogen, needs to be covered.

Coking requires a special mention. The constant demand imposed on all runs within a time period extends to petroleum coke. This is in order to keep the same envelope for all runs and maintain consistency and comparability. Freeing up coke demand would give the model the opportunity to use more cokers at the expense of other conversion units. The choice would, however, be strongly influenced by the arbitrary assumption made regarding the price of coke relative to other products, rather than the indication of a structural requirement. We have tested this on some key cases and found that the availability of additional coke demand has only a marginal impact on investment and refinery energy consumption and CO_2 emissions. The fact that coker utilisation is constant for all cases in the time series should therefore be no surprise. This is, however, also consistent with the fact that the conversion level remains broadly the same. In the “marine distillate” step-out case, conversion is much higher and so is coker capacity. As this is at still constant coke demand this indicates a choice for lighter coker feedstocks.

The need for additional reformate splitters is related to the introduction of the 35% aromatics limit in gasoline in 2005.

As the sulphur specification of many product grades remains under pressure, additional distillate desulphurisation capacity is still required. Lowering PAH in diesel fuel requires dedicated gasoil dearomatisation units as what aromatics saturation is achieved through desulphurisation falls well short of what would be required for such ultra low PAH levels.

These improved products have a higher hydrogen/carbon ratio hence the massive increase in hydrogen production capacity. Note that the combination of the three quality step-out cases in the last column results in nearly doubling the hydrogen capacity utilisation.

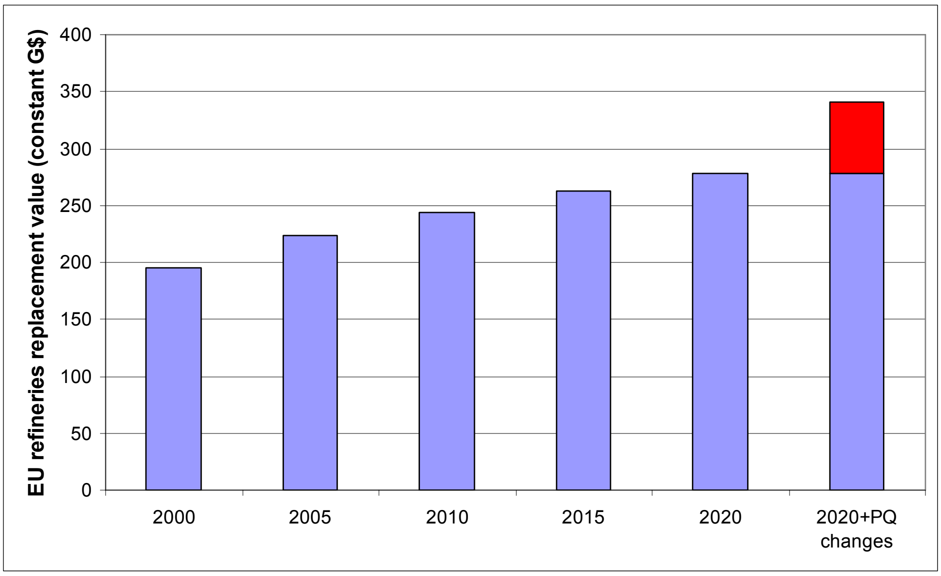
Steam cracking capacity increases in line with demand for olefins. There are also changes in the composition of the feed available to steam crackers, further discussed in *section 6.5*.

The sum of the requirements of the three step-out cases is somewhat less than when all three constraints are combined indicating a degree of synergy, albeit limited (the total extra capital expenditure for the three cases would be 72 G$ against 67 for the combined case).

Although some of the new plants are simply replacing existing ones, most of them genuinely represent additional processing and therefore contribute to increasing the complexity of the refineries. A rough measure of complexity is the replacement value of utilised plants. On this basis **Figure 6** shows that refinery complexity needs to increase by over 40% to 2020 and up to nearly 75% should the additional quality changes come to pass.

Note:
The increases in replacement value shown in **Figure 6** are somewhat lower than the capex numbers in **Table 6**. This is because the latter take into account the size of new plants required in the different regions, some of which are sub-optimal in size and therefore more expensive per tonne of new capacity. In **Figure 6** we have used a single "$ investment cost / t capacity" factor for each process unit.

Figure 6 EU refineries replacement value (constant $, process units only)



At this point it is useful to reflect on the implications of such large investment requirements. Beyond the availability of funds, there is an issue of practical feasibility in terms of ability to muster the appropriate resources for such a large number of potential projects. Even assuming a high degree of concentration and optimisation of investments, the average size of a hydrocracker is unlikely to be much beyond 2 Mt/a. Just building 40 Mt/a new hydrocracking capacity between 2005 and 2020 would then require 20 major projects.

Of course this study starts from the premise that EU refineries continue to meet the demand while imports and exports remain constant. The magnitude of the implied investments suggests that in reality, a proportion of the additional demand will have to be met through trade.

6.2. REFINERY ENERGY CONSUMPTION AND CO_2 EMISSIONS

New plants do not necessarily require more energy if they replace existing ones but, as we have seen above, in this case most new plants are "additional" i.e. represent real additional processing. The impact on the energy consumption of refineries is shown in **Figure 7a/b** and **Table 7**.

Figure 7a Evolution of total energy consumption of EU refineries
(No efficiency improvement after 2005)

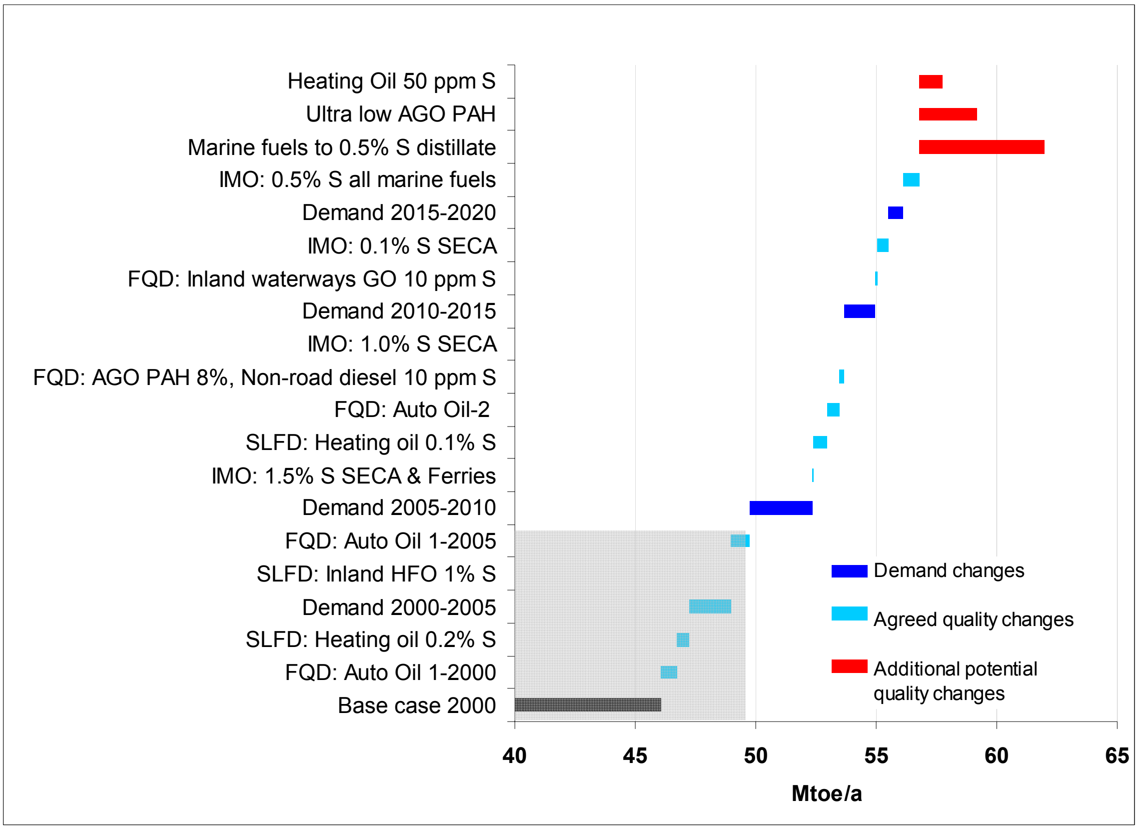


Figure 7b Share of demand and product quality in the increase of EU refinery energy consumption between 2005 and 2020
(No efficiency improvement after 2005)

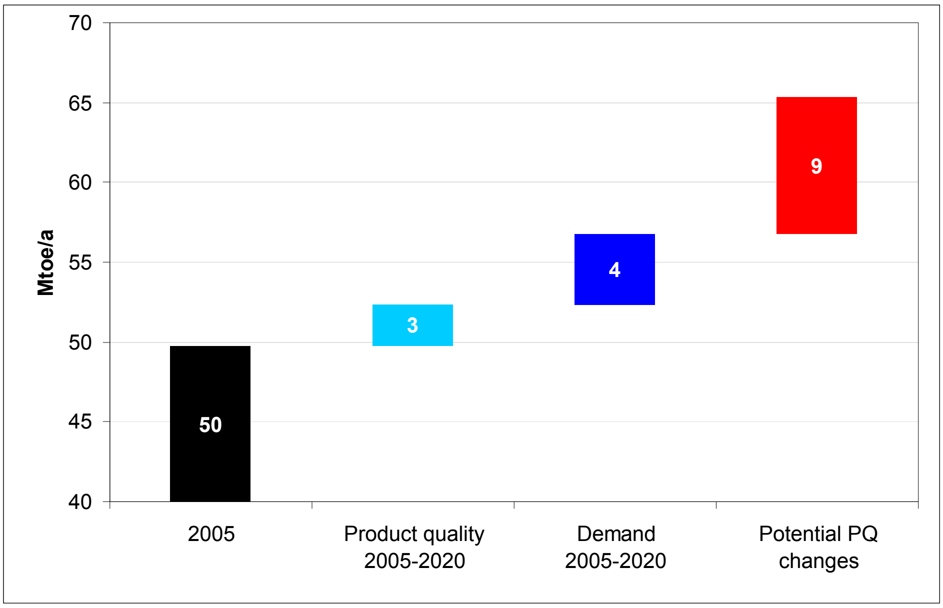


Table 7 Energy consumption and CO_2 emissions in EU refineries
(No efficiency improvement after 2005)

		Timeline					Potential product quality changes			
		2000	2005	2010	2015	2020	Marine fuel to 0.5% S distillate	Ultra low diesel fuel PAH	Heating oil to 50 ppm S	All three changes
							Relative to 2020 end point			
Energy consumption	Mtoe/a	45.1	49.7	52.4	55.0	56.8	5.2	2.4	1.0	8.5
	% of tot. feed	7.0%	7.5%	7.5%	7.6%	7.9%	0.7%	0.3%	0.1%	1.1%
Refinery fuel composition										
Refinery and imported gas		74.9%	65.1%	55.5%	53.0%	50.3%	47.1%	44.6%	49.0%	46.4%
Residuel fuels		11.9%	22.8%	34.5%	37.6%	39.3%	44.4%	46.0%	40.7%	45.7%
FCC coke		13.3%	12.1%	10.0%	9.4%	10.4%	8.5%	9.4%	10.3%	7.9%
CO_2 emissions							Relative to 2020 end point			
From refineries	Mt/a	122	144	159	171	180	30	14	4	46
	t/t of tot. feed	0.18	0.21	0.22	0.23	0.24	0.04	0.02	0.01	0.06
From fuel products	Mt/a	1882	1916	1986	2011	1992	-13	-6	-1	-19
Total	Mt/a	2002	2058	2143	2180	2170	16	8	3	27
(including burning of fuel products)										
From refineries	% of total	6.1%	7.0%	7.4%	7.8%	8.3%	9.6%	8.9%	8.5%	10.3%

The total energy requirement of EU refineries increases from 45 Mtoe/a in 2000 to 57 Mtoe/a in 2020. The combination of the three “step-out” quality changes could add another 8.5 Mt/a. The specific energy requirement also increases from 7.0% of total feed in 2005 to 7.9% in 2020, jumping to 9.0% with the extra quality changes. Our stepwise approach allows us to estimate the relative share of demand and product quality changes in the total (**Figure 7b**). The potential quality changes could more than double the total increase from 2005.

With these increased energy needs additional CO_2 emissions are incurred (**Figure 8a/b**). From an estimated 122 Mt in 2000, EU refinery CO_2 emissions reached some 144 Mt in 2005 and are set to grow to 180 Mt in 2020. From 2005 onwards, quality and demand changes each account for roughly 50% of the total increase (**Figure 8b**). With the extra quality changes, this could reach 226 Mt. The specific emissions (in tonne CO_2 per tonne of feedstock processed) are also set to increase (by 45% if including all the additional quality changes compared to 2005).

The total CO_2 emissions associated with EU petroleum products production and use (i.e. including the emissions incurred when burning the fuel products) increase by a larger amount because of the slowly increasing total demand. Note that the refinery emissions as a proportion of the total increase from 6.1% in 2000 to 8.3% in 2020 and could reach 10.3% with the step-out quality cases.

The relationship between energy and CO_2 emissions is not straightforward however. The obvious link between energy consumption and CO_2 emissions is the carbon content of the fuel burnt. Refineries largely produce their own fuel, burning in priority those streams that have no or little commercial outlet or value. The coke deposited on the FCC catalyst is burnt as part of the process, generating energy, most of which is used to feed the endothermic cracking reactions and supply heat for product separation. When heavy feeds are processed surplus heat is produced and exported to other process units. A number of refinery processes produce light hydrocarbon gases (methane and ethane) that generally do not have any practical commercial outlets and must therefore be burnt in the refinery. The balance of energy needs is provided by internally produced liquid fuels (often residual fuels as far as the refinery sulphur and other emission limits allow) and/or imported natural gas. Again for consistency reason we have allowed the same amount of natural gas import in all cases (3 Mt/a). Some of this gas may be used to produce hydrogen and the balance is used for energy generation. The combined sulphur content of the fuel burnt has been kept to a maximum of 1% (including FCC coke), consistent with the "bubble concept" in force today (impact of changes to this regulation is discussed in *section 6.6*). **Table 7** reveals very significant changes to the composition of the fuel pool as determined by the model over the years. The proportion of liquid in the pool nearly doubles from 23 to 39% between 2005 and 2020, further increasing to 45% with the step-out quality changes. This reflects the increased shortage of fuel gas as energy consumption increases while at the same time utilisation of large producers such as FCC and visbreakers is slowly eroding.

Figure 8a Evolution of CO_2 emissions from EU refineries
(No efficiency improvement after 2005)

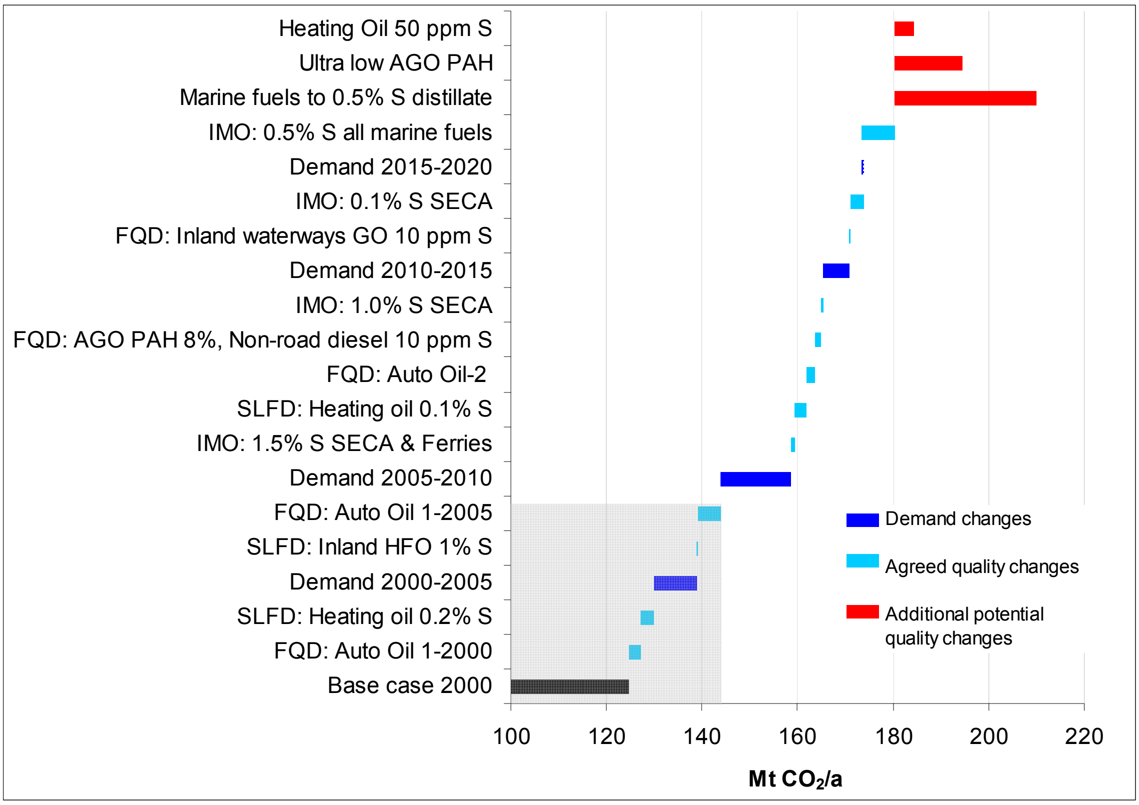
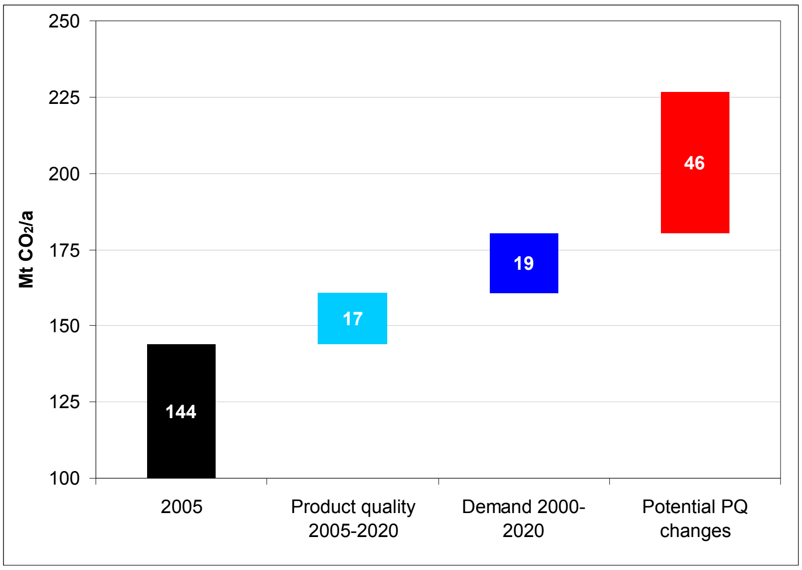


Figure 8b Share of demand and product quality in the increase of EU refinery CO_2 emissions between 2005 and 2020
(No efficiency improvement after 2005)



The second source of CO_2 emissions is hydrogen production from hydrocarbons. While it indeed requires energy, hydrogen production also results in the release of CO_2 from the decarbonisation of the hydrocarbon feed ("chemical" CO_2). In the most favourable case, methane is used in the steam reforming process according to

$$CH_4 + 2\ H_2O \rightarrow CO_2 + 4\ H_2$$

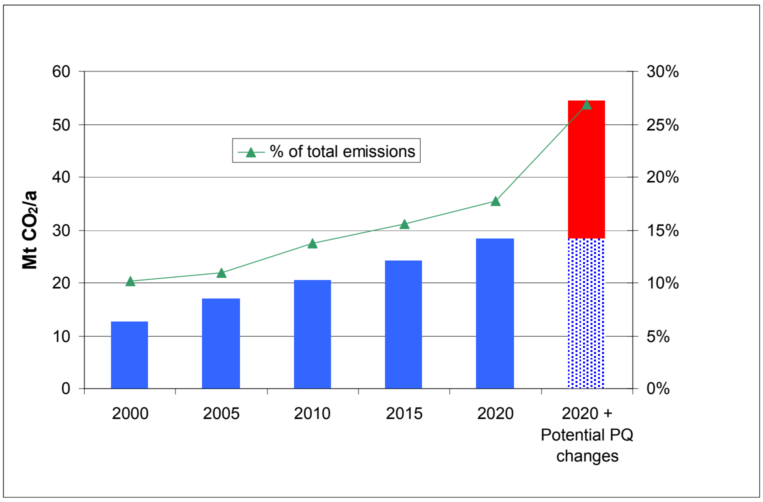
Out of 8 grams of hydrogen produced, 4 come from water and the other 4 from the hydrocarbon feed, releasing 44 g of CO_2. The ratio is less favourable when heavier feeds are used. **Figure 9** shows how the relentless increase of hydrogen demand in the refineries results in an increase of the absolute "chemical" CO_2 production and of its share of the total CO_2 emissions from about 10% currently to 15% in 2020 and possibly to 27% with the additional quality changes.

At the same time the proportion of refinery gas in the hydrogen plant feed increases from 37% in 2005 to 63% in 2020 and further to 81% for the step-out case. Importing more natural gas would of course redress the balance and result in lower refinery CO_2 emissions (see *section 7.2*).

It is worth noting that, in all cases, the model uses essentially methane and some ethane as feedstock for extra hydrogen manufacture so that the "chemical" CO_2 emissions are as low as they practically can be (in the model, refinery gas is defined as exclusively methane and ethane). Propane and heavier hydrocarbons are allowed as hydrogen plant feed but have not been used in the cases considered). One of the options open to refineries to destroy residue is gasification for combined production of electricity and hydrogen. Although this is overall a very efficient way to use residue, it would result in much larger CO_2 emissions per tonne of hydrogen.

Table 7 also shows the CO_2 potentially emitted by the fuel products produced by the refineries as well as the total balance, illustrating the emissions gain when burning fuels that contain relatively more hydrogen and the net loss resulting from the combined impact of processing and use.

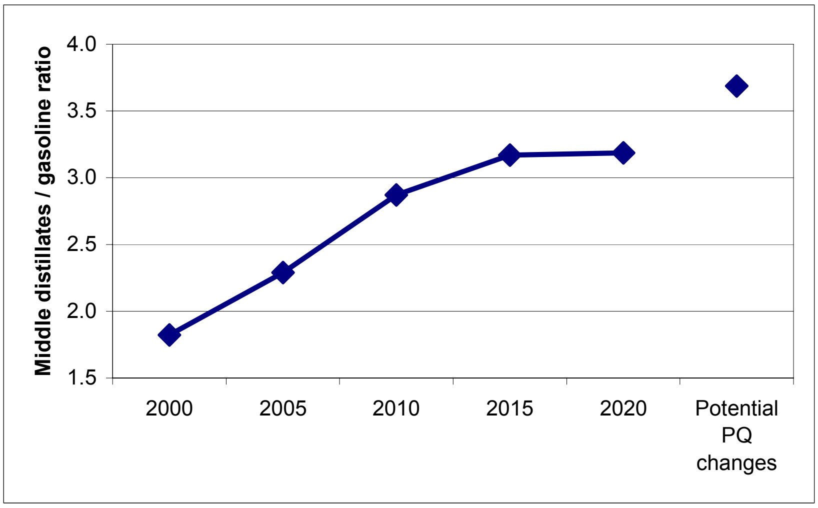
Figure 9 "Chemical" CO_2 from hydrogen production in EU refineries
(does not include emissions from energy used for hydrogen production)



6.3. MAIN DRIVERS: MIDDLE DISTILLATE / GASOLINE RATIO AND SULPHUR REMOVAL

At the beginning of this section we noted the steady increase of the middle distillate to gasoline (MD/G) ratio, shown graphically in **Figure 10.** The relevance of this parameter for EU refineries has been illustrated in an earlier CONCAWE report [5]. Ratios above are very high indeed and in the range where we previously found evidence of a possible reversal of the overall "well-to-wheels" advantage of diesel over gasoline due to excessive extra CO_2 emissions in refineries.

Figure 10 Evolution of the middle distillate / gasoline ratio



Figures 11 and 12a/b show how both investment costs and CO_2 emissions (both absolute and relative to feed) increase with the MD/G ratio. In order to clarify this relationship we have run an additional set of cases representing the 2000-2020 time series at constant product quality (2005 specifications) also including a point representing a switch to (high sulphur) marine distillates. For this additional series both investment and CO_2 emissions show a relationship with the MD/G ratio which is consistent with our previous findings, i.e. a steady increase with a sharp upturn of the slope at values of the ratio between 3.0 to 3.5. For the 2000-2005 time series with actual specifications the correlation is not as good because there are other factors at play, chiefly the desulphurisation of a number of products. This is of course particularly noticeable in 2020 when marine fuels need to be desulphurised to 0.5%. The step-out cases stray further out of line as they bring more desulphurisation and also dearomatisation in the low PAH case. The marine distillate case combines both although the impact of desulphurisation to 0.5% appears very small. This is because in the unconstrained case, the model produces a marine distillate with a sulphur content of only 1.2%.

Figure 11 Impact of middle distillate / gasoline ratio on capital expenditure

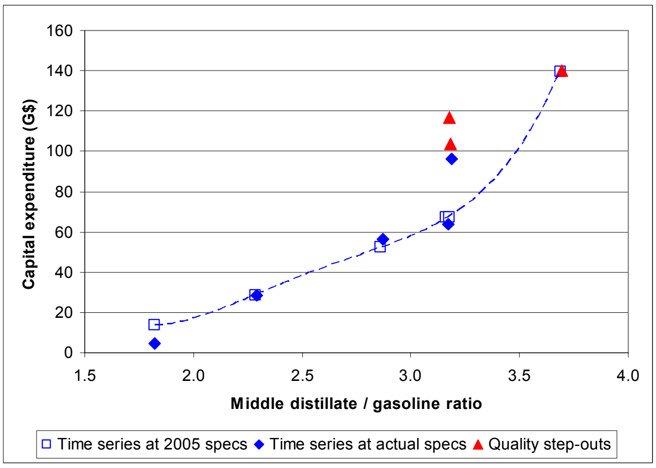
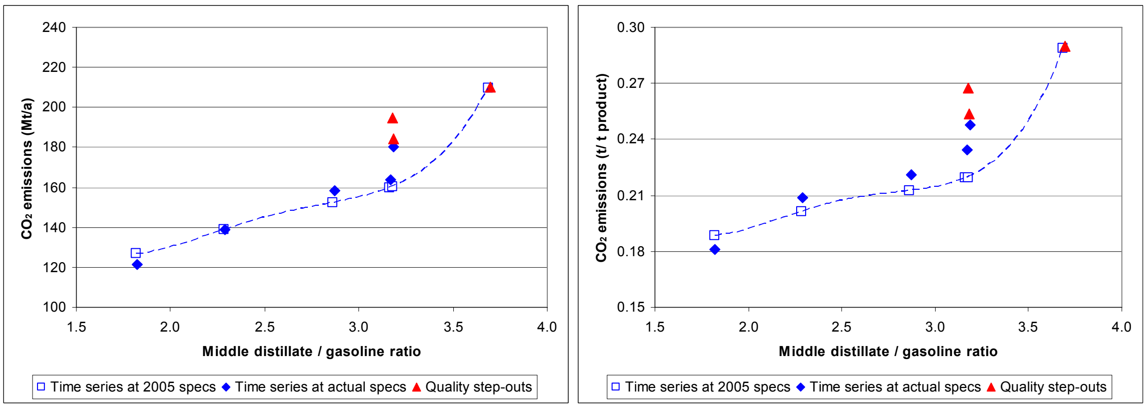


Figure 12a/b Impact of the middle distillate / gasoline ratio on EU refinery CO_2 emissions



The proportion of sulphur in the crude actually removed (and recovered as sulphur) shows a remarkable increase. **Figure 13** shows that, by 2020, EU refineries will have to remove 70% of feed sulphur, increasing the tonnage of sulphur recovered nearly threefold. Note that the additional changes in product quality considered here have little impact on sulphur removal as they mostly concern other properties.

Table 8 details the origin of the increased sulphur removal. By 2020 roughly half of the increase is related to marine fuels which, as per the IMO regulation, will then have been almost completely desulphurised. Demand changes account for slightly more than a quarter of the increase, the balance being attributable to road and other inland fuels.

Figure 13 Fraction of feed sulphur removed

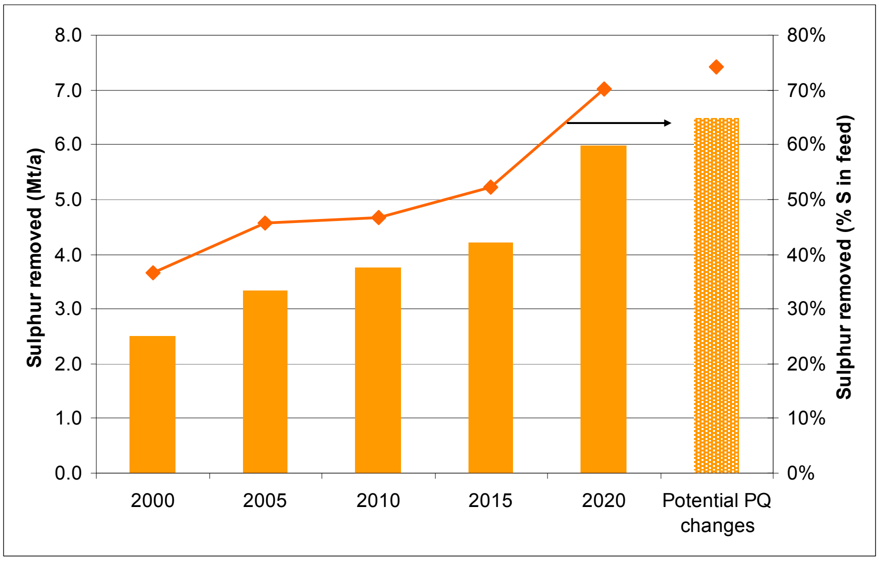


Table 8 Respective roles of product desulphurisation and demand on sulphur removal increase from 2000

Figures in Mt/a of sulphur (over 2000 production of 2.49 Mt/a)	2005	2010	2015	2020	Potential PQ changes
Product desulphurisation					
Road fuels	0.12	0.18	0.18	0.18	0.19
Marine fuels		0.42	0.55	1.83	2.22
Other fuels	0.42	0.53	0.53	0.53	0.62
Demand changes	0.30	0.74	1.05	0.96	0.96
Total	0.84	1.88	2.31	3.50	3.99

In **Figures 14 and 15a/b** we have plotted refinery investments and CO_2 emissions versus sulphur removed for both the 2000/2020 time series and the step-out cases. They also show a good correlation between sulphur removed and both investment costs and CO_2 emissions at least for the time series. In other words sulphur removal acts as a kind of proxy for severity of operations. Not surprisingly the two step-out cases that address other issues such as PAH in diesel and switch from residual to distillate marine fuels are out of line.

Figure 14 Impact of feed sulphur removal on capital expenditure

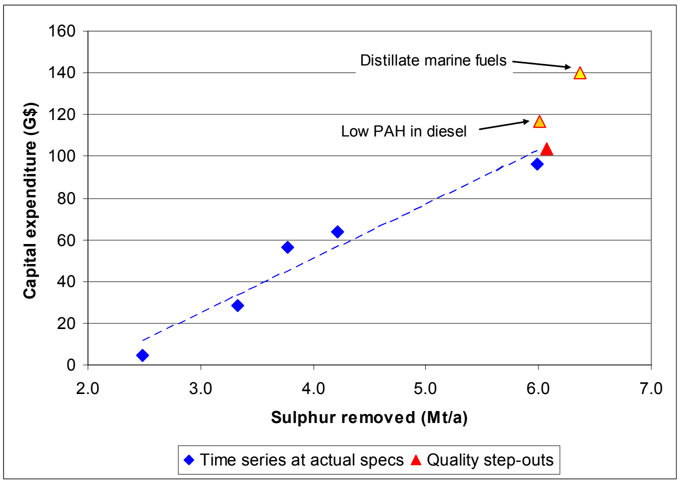
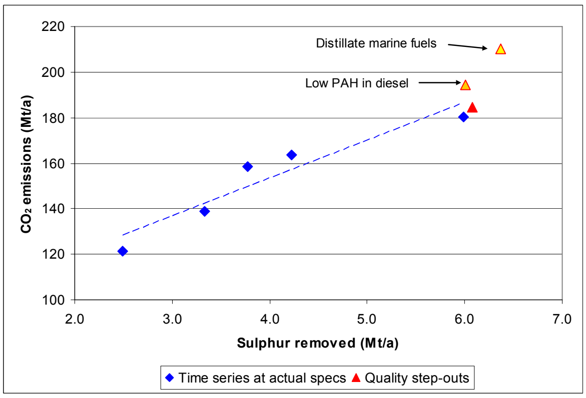
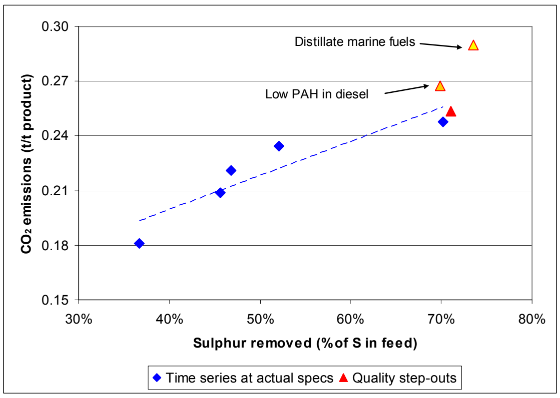


Figure 15a/b Impact of feed sulphur removal on EU refinery CO_2 emissions





6.4. SENSITIVITY TO CO_2 PRICE

One of the important features of the future EU industry including refining will be the increasing cost attached to CO_2 emissions, reflected in a CO_2 market price under the EU Emissions Trading Scheme (EU ETS). All above study cases were run without a CO_2 price. It is of course of interest to investigate whether the increasing cost of CO_2 emissions would markedly influence the model solution or, in other words, whether more or less CO_2-intensive solutions are likely to be available to EU refiners to achieve the same production in both quantity and quality. It must be understood that this section does not explore the CO_2 mitigation options open to refiners. These are discussed in *section 7*.

We have repeated the 2020 case with a range of CO_2 prices from 0 to 100 \$/t. **Table 9** and **Figure 16** show that there is some scope for more energy and CO_2 efficient investment but the gain remains relatively small. This should in fact not come as a surprise for, as long as the same products have to be made from the same feeds, all alternative processing routes are more or less equivalent in terms of cost, energy and CO_2 emissions.

The additional cost burden of CO_2 emissions for the refiners obviously would increase proportionally to the CO_2 price reaching nearly 18 G$/a at 100 $/t CO_2. The net cost of marginal CO_2 abatement can be calculated as the total additional refiner's cost divided by the number of tonnes of CO_2 not produced. The total cost must account for capital charge, operating costs for additional plants and the benefit of fuel savings. The latter would depend on the general crude and product price level. With our generic price set (based on NWE 2007 average, see **Appendix 1**) the net CO_2 cost starts at 160 $/t in 2005, exceeding 250 $/t at the 100 $/t CO_2 price mark.

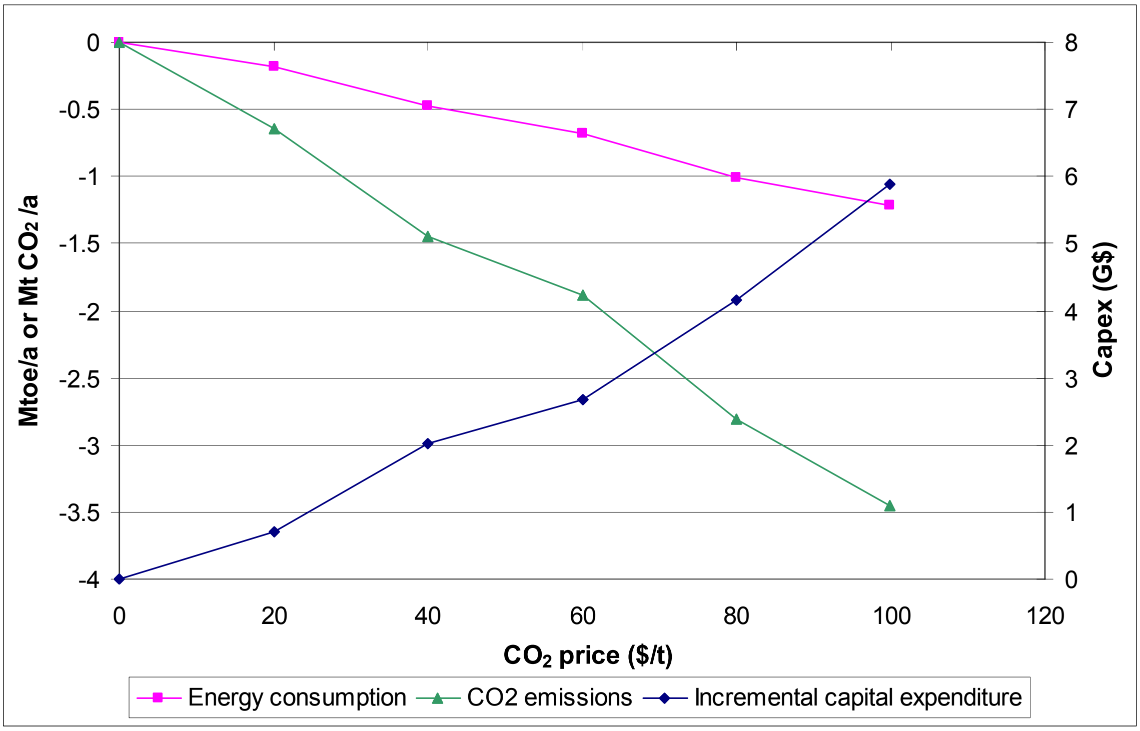
Table 9 Sensitivity of model solution to CO_2 price

CO_2 price	$/t	0	20	40	60	80	100
Incremental capital expenditure	G$	Ref	0.70	2.0	2.7	4.2	5.9
Total cost[(1)]		Ref	103	263	373	586	876
Energy consumption	Mtoe/a	56.8	56.6	56.3	56.1	55.8	55.6
CO2 emissions	Mt/a	180.3	179.6	178.8	178.4	177.5	176.8
Total refiner's cost of CO_2 emissions	G$/a	0.0	3.6	7.2	10.7	14.2	17.7
Net cost of marginal CO_2 reduction[(2)]	$/t	0.0	160	182	198	209	254

(1) Including capital charge

(2) Assuming refinery energy cost consistent with price set in Appendix 3

Figure 16 Sensitivity of model solution to CO_2 price



6.5. PETROCHEMICALS

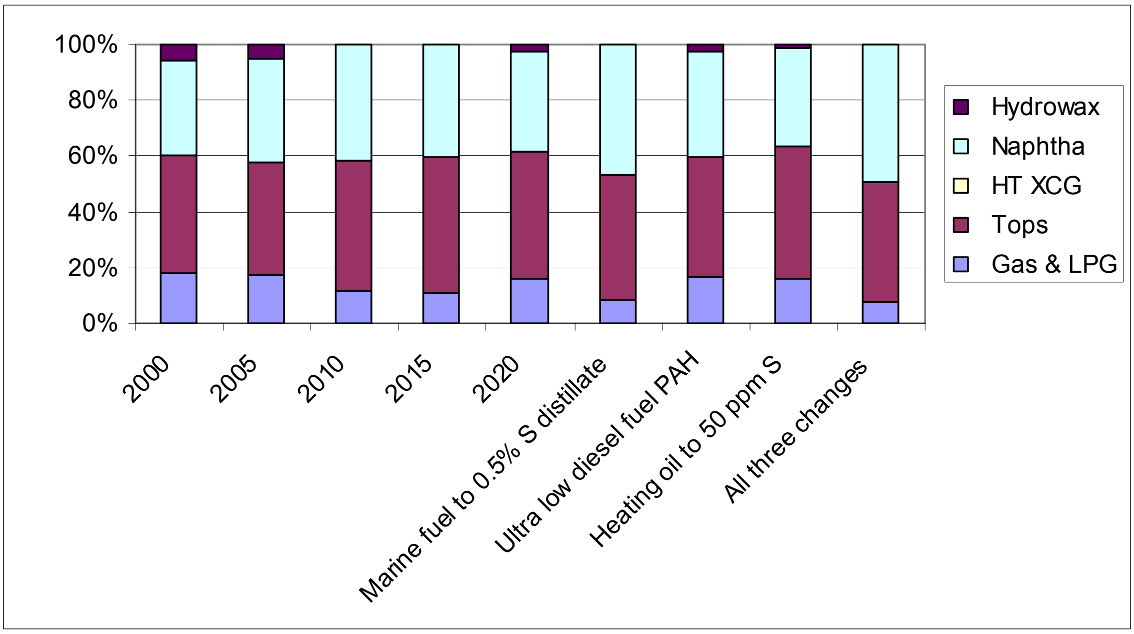
As was previously mentioned, the figures discussed above cover the complete scope of the simulations i.e. include petrochemical operations for light olefins and aromatics production. Because the model performs an integrated optimisation it is not possible to precisely isolate the share of petrochemical operations in the total numbers but an estimate can be made with some simplifying assumptions. **Table 10** summarises the figures relevant to petrochemicals for the main time series up to 2020.

Between 2005 and 2020 demand for olefins and BTX is expected to increase by about 10% and 40% respectively. This will have to be met by capacity increases. The model foresees a doubling of aromatic extraction capacity (these are refinery-based plants using reformate as feedstock. In the model the plants dealing with the pyrolysis gasoline are integrated into the steam crackers and not accounted for separately). There are some changes in the composition of the steam crackers feedstock as shown in **Figure 17**. Generally more tops become available with less heavy naphtha and LPG. On balance the olefins yield remains more or less constant around 57% (ethylene + propylene).

Table 10 Summary of Petrochemicals operation

		2000 (base)	2005	2010	2015	2020
Steam crackers feed	Mt/a	60.6	67.7	71.3	71.2	71.2
Ethane and LPG		18%	17%	11%	11%	17%
Light naphtha		42%	40%	47%	49%	47%
Heavy naphtha		34%	37%	42%	41%	38%
Hydrowax		6%	5%	0%	0%	3%
Production	Mt/a					
Olefins		37.6	41.5	42.6	43.5	46.0
BTX		12.9	14.1	15.6	17.5	19.6
Existing and new process plant throughput (Mt/a)						
Aromatics extraction		8	5	7	9	12
Steam cracker		61	68	71	72	74
New process plants capacity (Mt/a)			Relative to base 2000			
Aromatics extraction			0.7	1.2	1.9	4.5
Steam cracker			7.4	11.0	11.4	13.7
Capital expenditure	M$		3.8	6.2	6.3	8.2
Energy consumption	Mtoe/a	5.8	6.3	6.4	6.4	6.7
	% of tot. feed	9.6%	9.3%	9.0%	9.0%	9.4%
CO_2 emissions		15.7	18.1	19.4	20.0	21.3
	t/t of tot. feed	0.26	0.27	0.27	0.28	0.30

Figure 17 Steam crackers feed composition



6.6. REDUCTION OF THE MAXIMUM LIQUID REFINERY FUEL SULPHUR CONTENT TO 0.2%

Various pieces of legislation, and particularly the IPPC Directive, put pressure directly or indirectly on the maximum allowable sulphur content of the refinery fuel pool. Our base case assumes a limit of 1.0% sulphur under a “bubble” arrangement i.e. where only the average sulphur emissions from all sources are constrained. The exact figure that will prevail in 2020 is not entirely clear as legislation is not finalised while it is not certain that the bubble concept will still apply. In order to illustrate the impact of a major reduction of allowable sulphur emissions we have simulated a 0.2% maximum sulphur case for the liquid fuel, both without and with the possibility of additional natural gas imports (see also *section 7.2*).

Table 11 summarises the results compared to the 2020 end point discussed in the above sections.

The impact of refinery fuel sulphur reduction is complex. Rather unexpectedly, energy consumption goes down in both cases. Even without additional natural gas imports CO_2 emissions are also reduced. To explain this, one has to refer to *section 6.4* where we showed that the model has some capacity for reducing energy consumption and emissions when the associated cost increases. In this case the extra cost is introduced by way of a quality constraint. The cost of achieving this is however considerable, with a very large, and probably unrealistic, increase in residue desulphurisation capacity. For a saving of 4.3 Mt/a of CO_2 the cost is 2.8 G$ (after discounting the benefit of energy saving) i.e. about 650 $/t CO_2 saved.

When additional natural gas is allowed, it replaces marginal crude oil while the desulphurised residual material that was used as refinery fuel in the previous case must now be fully converted, hence the increase in vacuum distillation and hydrocracking capacity. As a result hydrogen demand is higher. CO_2 emissions decreased markedly of course as part of the crude intake is effectively replaced by natural gas.

Table 11 Impact of reducing refinery fuel sulphur content

		2020	2020, 0.2% S in refinery fuel	
		1.0% S in refinery fuel	No NG import	Unlimited NG import
Crude diet				
API gravity		35.1	35.1	35.3
Proportion of LS crude		45%	45%	47%
Sulphur content	% m/m	1.14%	1.13%	1.07%
Atm. Residue yield	% m/m	42.9%	42.9%	42.7%
Total production	Mt/a	728	728	728
Fraction of light products(1)		82.2%	82.2%	82.2%
Production ratios				
Diesel / gasoline		1.9	1.9	1.9
Gasoil / gasoline		2.6	2.6	2.6
Middle distillates / gasoline		3.2	3.2	3.2
Existing and new process plant throughput (Mt/a)				
Crude atmospheric distillation		723	722	701
Vacuum distillation		211	167	190
Visbreaking		65	46	46
Coking		11	12	12
FCC		108	116	112
Hydrocracking		77	68	86
Resid desulphurisation/conversion		79	125	103
Middle distillate hydrotreating		222	224	213
Hydrogen (in kt/a of H_2)		1283	1452	1540
Steam cracker		74	74	75
New process plants capacity (Mt/a)		Relative to base 2005	Delta	Delta
Crude atmospheric distillation		79	-1	-21
Vacuum distillation		7	-8	-6
Visbreaking		5	-1	-1
Coking		0	0	0
FCC		0	1	1
Hydrocracking		35	-13	13
Resid desulphurisation/conversion		71	46	24
Middle distillate hydrotreating		154	5	-6
Hydrogen (in kt/a of H_2)		1196	170	258
Steam cracker		14	-1	0
			Delta	Delta
Capital expenditure	G$	96.1	16.9	15.9
Total annual cost(1)	G$/a	24.6	2.8	1.7
			Delta	Delta
Energy consumption	Mtoe/a	56.8	-0.8	-0.6
	% of tot. feed	7.9%	-0.1%	0.2%
Refinery fuel composition				
Refinery and imported gas		50.3%	49.4%	84.4%
Residuel fuels		32.6%	6.2%	1.2%
Other liquids		6.6%	32.3%	2.9%
FCC coke		10.4%	12.0%	11.4%
CO_2 emissions			Delta	Delta
From refineries	Mt/a	180	-4.3	-20.1
	t/t of tot. feed	0.24	-0.01	-0.03
From fuel products	Mt/a	1992	2	2
Total (including burning of fuel products)	Mt/a	2170	-2	-19
From refineries	% of total	8.3%	8.1%	7.4%

(1) Including capital charge, excluding margin effects

6.7. COMPARISON WITH PREVIOUS STUDIES

As mentioned in the introduction CONCAWE has, in recent years, carried out several studies to evaluate the impact of specific measures on EU refineries. The present study incorporates all the individual measures considered in this past work although many aspects of both the underlying model data and base scenario have been somewhat modified/updated in terms e.g. of energy consumption, geographic scope (EU-27 v. EU-25) future demand and costs. In addition the present work considers each measure as integrated in a series of changes not all of which were previously foreseen so that synergies may exist that did not materialise before.

For these reasons it would not be expected to find precisely the same impact for individual measures. **Table 12** below gives a simple comparison of the impact in terms of CO_2 emissions, as found in the current work and in previous studies.

Table 12 Comparison of CO_2 emissions impacts with previous studies

Measure	This report	Previous studies		
	Mt CO_2/a		Published in	Ref
Auto Oil 1-2005	4.8	3.5	Report 8/05	2
Auto Oil-2	1.6	3.8	Report 8/05	2
Seca & Ferries 1.5% S	0.8	2.0	Report 2/06	4
RMF 0.5% S	7.0	4.7	Report 2/06	4
AGO PAH 2%	14.2	13.4	Report 7/05	3
Distillate marine fuel	29.8	33.0	Review 16.1	7
Total emission increase 2005-2015	26.9	19.7	Report 1/07	6

Although the figures are different they do not reveal major changes in trends. Some differences can be readily explained. For instance the reduced impact of distillate marine fuels originates mainly from the different specification attached to the “distillate” (it was similar to heating oil in the original study and has now been relaxed to DMB). The total emissions increase estimated in report 1/07 was based on a slightly different demand forecast and did not take account of all quality changes, particularly with regards to marine fuels. Others are more difficult to trace precisely and are the results of complex interactions within the model. The individual impacts of Auto Oil 1 and 2 are quite different but the total is quite close. It should be noted in this context that the model is set to maximise profit rather than minimise CO_2 emissions. Accordingly it does not always converge on the optimum solution in this regard.

This short analysis gives a sense of both the limitations in terms of the accuracy that can be expected from this type of analysis but also of its robustness in its ability to indicate trends.

7. MITIGATION MEASURES

The very significant increase of refinery CO_2 emissions described in the previous section have to be viewed in the context of the EU ETS (Greenhouse gases Emissions Trading Scheme as per Directive 2003/87/EC, currently under review) according to which EU refineries will be expected to decrease rather than increase their emissions or buy extra allowances on the market.

As discussed in *section 6.4*, the complexity of processing required for making the desired products for the EU market will result in a similar level of emissions, largely irrespective of the actual combination of processes used. Short of decreasing their activity and resorting to more extra EU trade, refiners have a limited number of options to affect this underlying trend. In the sections we examine the potential of energy efficiency, fuel switching, crude oil change and CO_2 Capture and Storage (CCS) in terms of both direct impact on refinery CO_2 emissions and actual effect on global emissions.

7.1. ENERGY EFFICIENCY

Increasing energy efficiency, i.e. using less energy to deliver the same service, is undoubtedly a no-regret option, and it is the only one that offers both energy and GHG emission savings. This is not a new pursuit in an industry where fuel represents the single highest cost item, particularly at current price levels. Between 1990 and 2005, EU refiners have increased the efficiency of their operations by an estimated 13%. Part of this is the result of sustained focus on energy saving in everyday operation as well as investments in e.g. improved heat integration or energy efficient pumps and compressors. The “low-hanging fruits” have long been picked though, and improvements in recent years have already involved complex and expensive schemes. A significant part of the efficiency improvements has been achieved by installing highly efficient combined heat and power plants (CHP) in replacement of simple steam boilers and imported electricity. Further opportunities still exist but are increasingly difficult to achieve and less cost-effective.

The extra cost of energy brought about by CO_2 pricing will provide an additional incentive for energy saving projects. Energy management is, however, a site-specific issue and it is difficult to take an overall view of what might be achievable. Starting from the historical figure above, we have assumed a general 0.5% improvement per year, with in addition a 20% better energy performance for new plants compared to existing ones at any given time. It has to be emphasised that this is not a forecast based on hard technical data, but rather a challenging scenario. **Figure 18 and 19** illustrate the impact of such efficiency improvements in terms of energy consumption and CO_2 emissions compared to the base case presented in *section 6* and for the 2020 end point.

Energy efficiency improvements can, to a large extent, compensate for the increased energy requirement to 2020 as long as the extra product quality changes do not materialise.

The situation is less favourable for CO_2 emissions. As alluded to before, this is due in part to fuel pool changes, as future processing schemes tend to produce relatively less fuel gas which is then compensated by additional use of liquid fuel, but also to additional emissions that are generated when more “chemical” CO_2 is produced. The potential legislation envisaged would be particularly hydrogen intensive and imply a further large increase.

Figure 18 Potential of energy efficiency measure to mitigate EU refinery energy consumption increase in 2020

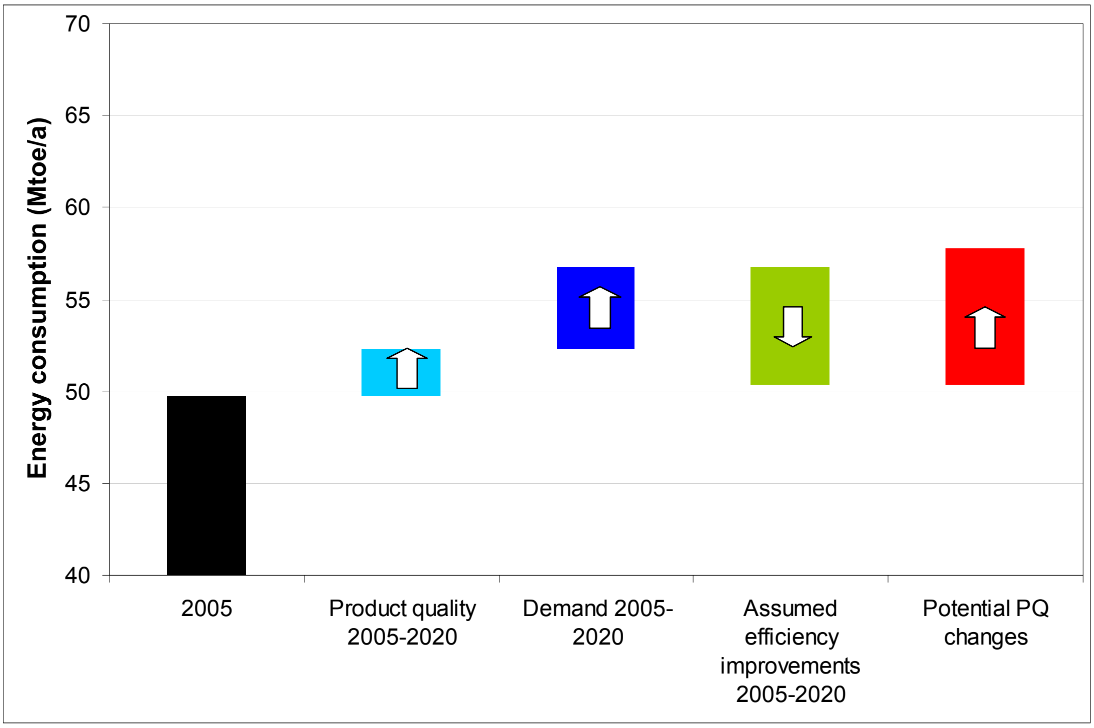
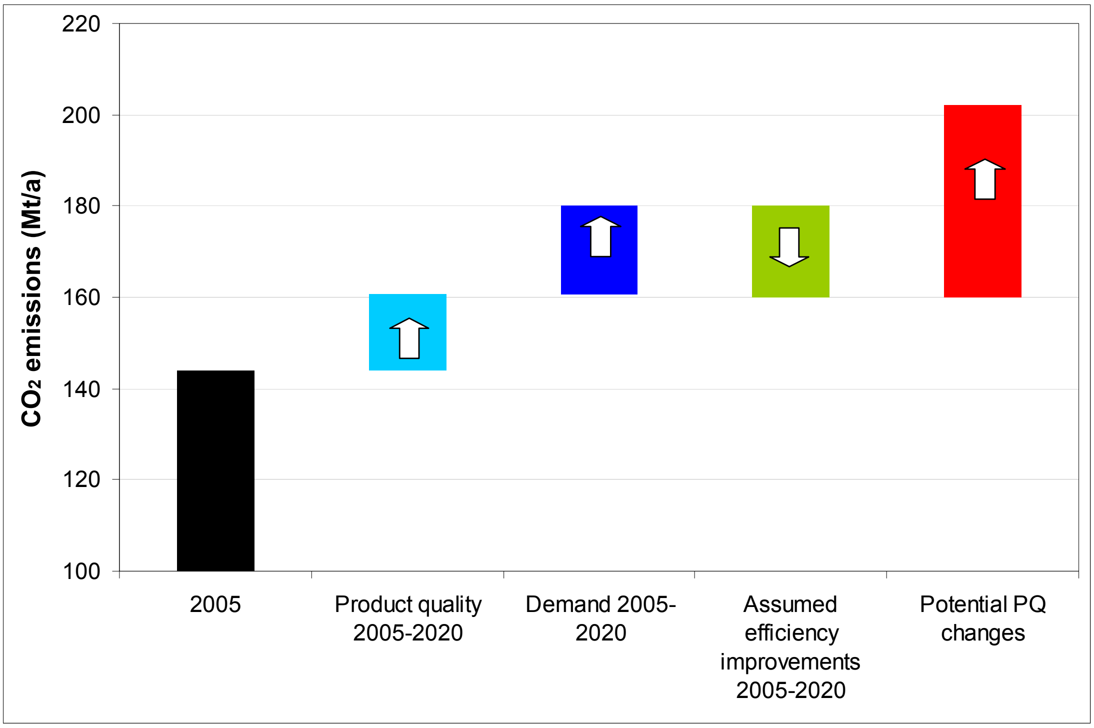


Figure 19 Potential of energy efficiency measure to mitigate EU refinery CO_2 emissions increase in 2020



7.2. FUEL SUBSTITUTION

The majority of fuels burned in refineries are self-generated in the form of light cases (C_1-C_2) and, in refineries that operate a Fluid Catalytic Cracker (FCC), the coke that is formed on the circulating catalyst as part of the process. Mostly as a result of emission control legislation and specific local environmental pressure, a number of EU refineries have already replaced heavy fuel oil by imported natural gas (currently 5-10% of refinery energy use). The balance of their requirement (about 25% on average) has traditionally been provided by liquid fuel, mostly low value residues that the refineries are equipped to handle. In that respect refineries are very effective at efficiently burning low value fuels that would otherwise need to be upgraded or displace other fuels.

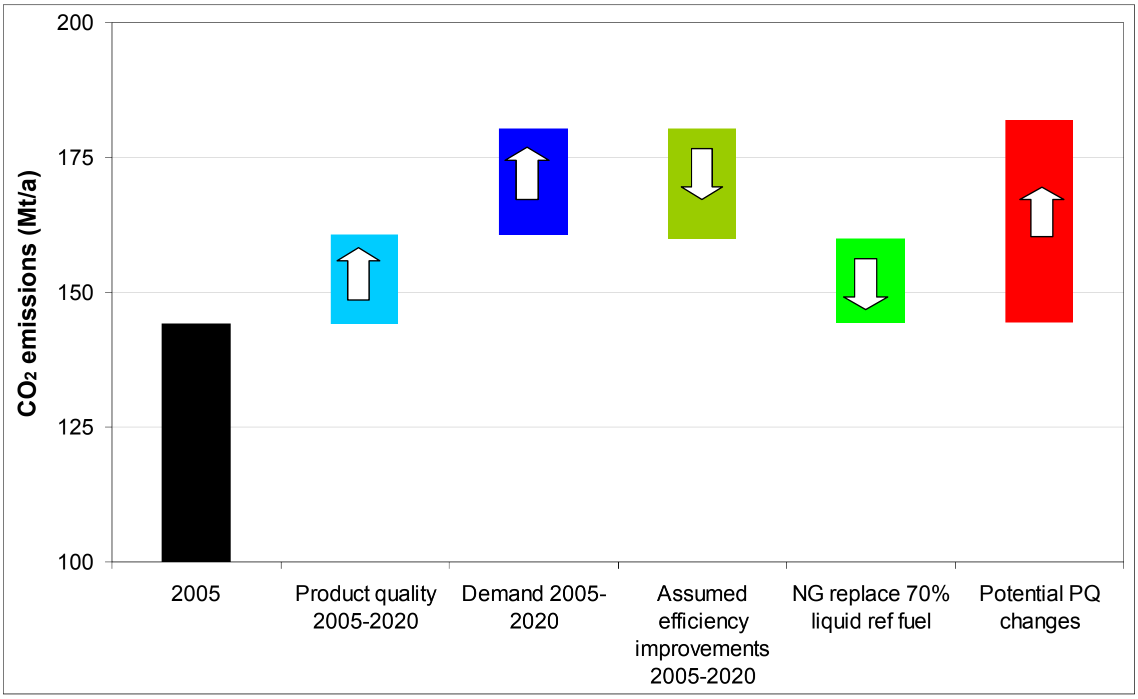
Replacing more liquid fuel by natural gas is of course a way to reduce direct CO_2 emissions from a refinery site as the emission factor of liquid fuel is in the order of 0.075 kg CO_2/GJ compared to 0.055 for pure methane.

We have seen (**Table 7**) that our model shows a steady increase of the proportion of liquid fuel in the fuel pool as a combined result of a relative decrease of refinery gas production and an increase of demand for light hydrocarbons for hydrogen manufacture (note that in 2005 the model shows a liquid fuel share of 23%, possibly slightly below the actual average figure although this is not known with any certainty). Starting now from the 2020 end point that includes improving energy efficiency, we simulated liquid fuel substitution by increasing the amount of natural gas imports, in order to arrive at a level of liquid fuel consumption equivalent to about 70% of that used in 2005 (100% substitution would not be realistically achievable as a number of refineries do not have access to a gas supply today and are unlikely to have it in the future). This resulted in a 15.6 Mt/a CO_2 reduction. We assumed that the unused heavy fuel would be converted (i.e. that the refinery output would remain constant) which explains why the reduction is somewhat less than would have been expected purely on the basis of the relative emission factors (about 18 Mt/a) as additional energy and hydrogen are required to convert the extra residue.

Figure 20 shows that the combination of challenging efficiency improvements and a switch to natural gas can do no more than approximately stabilise refinery emissions, assuming no further product quality legislation.

Importantly it must be pointed out that, although this fuel substitution does reduce emissions from refineries, its net effect on global emissions is not as straightforward. In effect it comes down to substituting crude oil by natural gas. From the point of view of global CO_2 emissions, this only represents a true reduction if it effectively causes additional natural gas to be produced and used. In reality this may not always be the case, as the increased natural gas demand in Europe may cause users in other regions to switch to cheaper and more carbon-intensive fuels. As mentioned above we have assumed that the unused heavy fuel would be converted. Again, this may not reflect the reality in all refineries, particularly in the simplest ones that would seek to sell the extra fuel rather than invest to convert it. It would then also displace other fuels in the market.

Figure 20 Impact of liquid fuel substitution by natural gas on EU refineries CO_2 emissions



7.3. USING LIGHTER CRUDE OIL

It is often suggested that processing lighter crude oil would be a way to reduce refinery emissions. It is undoubtedly correct that heavier crudes require more processing energy to achieve the same product yield pattern, because they contain more residual material that needs to be converted and also generally more sulphur that needs removing. As crudes tend to become heavier worldwide, the average crude diet in Europe is expected to follow this trend, albeit at a fairly slow rate compared to other regions of the world. This is because a number of light crude producing provinces are within easy reach of Europe where, as a result of prolonged availability of North Sea crudes, a number of refineries are well suited to light crude processing.

In our modelling we recognise this reality, but also use a heavy Middle East crude as incremental feed. In order to illustrate the impact of a lighter crude diet we have, in a sensitivity case, made the assumption that all heavy Middle East crude over and above what was in use in 2000 would be replaced by a light North Sea type crude (Brent). This represents a major shift of some 69 Mt/a (nearly 1.5 Mbbl/d) from heavy to light crude, roughly 10% of the total crude intake. The results are shown in **Table 13**.

In this case, the energy consumption of the refineries is reduced by 4.8%. The reduction of refinery CO_2 emissions is higher at 7.9% for two reasons:

- With a lighter crude, less conversion and less desulphurisation are required, resulting in a lower requirement for hydrogen and a lower “carbon loss” i.e. lower CO_2 emissions from decarbonisation of hydrocarbons,

- The refinery fuel diet has a somewhat lower emission factor in the case of the lighter crude, with more fuel gas and less FCC coke.

Table 13 Impact of increased light crude processing on refinery CO_2 emissions

Case	2020		Delta	
	Reference	Light marginal crude		
Crude diet (Mt/a)				
Total	715	711	-4	-0.6%
Light North Sea			69	
Heavy ME			-73	
% light crude	45%	55%	10%	
Average %S	1.12%	0.90%	-0.22%	
Fuel Consumption (Mtoe)	50.3	47.9	-2.4	-4.8%
CO_2 emissions (Mt/a)				
From refineries	160	147	-13	-7.9%
"Chemical' CO_2 from hydrogen production	28	25	-3	-11.4%
Total inc. burning of fuel products	2150	2136	-14	-0.6%

The CO_2 emissions reduction from using lighter crude increases only from 13 to 14 Mt/a when including the emissions from burning the fuel products, reflecting the fact that the product slate remains the same with only marginal differences in carbon/hydrogen content. When compared to the total emissions this reduction is, however, only 0.6%.

The above calculation considers only refining and does not make any assumptions with regards to the GHG footprint associated with production and transport of crude oil. There is no correlation between crude quality and extraction and/or transport energy, and the difference could go either way depending on the actual crude origins being considered.

These impacts may seem significant to some but there are other crucial points to consider:

- Whether Europe would be able to attract such a large additional amount of light crude can be a matter of conjecture but, in any case, crude oil consumption is largely a “zero sum game” when considered worldwide. Should Europe be successful in doing so, other world regions would have to process the heavier grades and emit correspondingly more CO_2. This would effectively cancel out any benefit and potentially lead to additional transport of crudes.

- Over the years, refineries have become gradually more complex in order to be able to process increasingly heavier crudes, thereby transforming low value residues into high value distillates. With decreasing resources of light crudes, it is important that refineries worldwide invest in that sort of complexity. Processing light crude is in fact a kind of “poor man’s option” that can avoid investment in a more sophisticated tool. It replaces capital expenditure by higher crude cost and therefore reduces the profitability of refineries. It would also tend to make refineries less flexible, less able to take opportunities of cheap crudes and more dependent on a declining and ever popular resource of light crudes.

Global crude oil composition is essentially fixed and therefore the major determinant of energy usage and CO_2 emissions in the global refining sector is the product pattern required in terms of both quality and quantity, which in turn determines the required level of residue conversion, the type of conversion unit and the amount of post-treating of intermediate products.

7.4. THE POTENTIAL OF CCS IN EU REFINERIES

CO_2 Capture and storage or “CCS” is a technology under development that is attracting a lot of attention as possibly the only acceptable way to continue to use fossil carbon resources in the next decades. Development has so far focussed on large single point emitters such as (coal fired) power stations where economies of scale can be realised. A number of demonstration projects are being considered with a view to develop such full-size plants at the 2020 horizon at the earliest. The legislative framework, particularly with regard to long term liabilities, still needs clarification.

Although figures are still a matter of debate, CCS will be costly, not the least because it requires additional energy (possibly as much as 30-40%) for capturing, separating, possibly treating CO_2, then transporting it and safely storing it for the long term. Capture will by far be the most expensive step and will be significantly cheaper and less energy intensive when concentrated CO_2 streams are available. For this reason power generation schemes involving oxy-combustion or gasification followed by hydrogen production are being contemplated. These schemes can produce highly concentrated CO_2 streams that are much easier to capture. Although there are trade-offs in terms of cost and energy consumption (e.g. to produce pure oxygen) many believe these schemes will carry an overall advantage.

In refineries, a small portion of the total CO_2 is emitted in concentrated form, essentially from older hydrogen plants where the “chemical” CO_2 is separated from the hydrogen stream through solvent extraction. Modern hydrogen plants using pressure swing absorption technology which produces a mixed gas used as additional fuel. The balance of the CO_2 is emitted in dilute form in the flue gases from a large number of large and small process heaters and utility boilers so that each of these multiple sources presents a specific challenge in terms of CO_2 capture. Oxy-combustion is uncharted territory in refineries and would present specific issues for process heaters.

The other prerequisite for a CCS project is the availability of a suitable geological storage structure within reasonable distance. Many options have been considered amongst which depleted oil and gas fields and, mostly, deep saline aquifers are the most promising. There are potentially enough such structures in Europe to store a large part of the continent’s emissions for many years. However, actual development of particular sites will require detailed evaluation.

In all cases a CO_2 transport infrastructure will be required, mostly in the form of pipelines. Such infrastructures are only likely to develop around large emitters such as fossil fuel power stations, eventually enabling smaller emitters to join the scheme at an acceptable cost.

One of the many challenges for CCS projects will be to coordinate the development of all three aspects – capture, transport, storage – at the same time as none of the three would make sense without the other two. Many factors will have to be managed including public acceptance for laying pipelines and locating storage sites.

Some refineries may develop CCS projects based on a combination of favourable local circumstances. In the next 15 years this will be the exception rather than the rule. For the longer term, the viability of wider use of CCS in refineries remains to be demonstrated.

8. INTRODUCTION OF BIOFUELS: LOW ROAD FUELS DEMAND SCENARIO

The already current and foreseen introduction of biofuels in EU road fuels will undoubtedly have an impact on demand for their fossil equivalent. In as much as Europe already relies on trade to balance refinery production and demand, one could argue that biofuels will simply displace trade for other products: bio-diesel would reduce diesel imports while ethanol would cause an increase of gasoline exports. Production from EU refineries would be largely unaffected. The other extreme would be to keep import/export constant and reduce refinery runs in order to compensate for the additional biofuel volumes. Globally though introducing biofuels somewhere in the world should reduce demand for their fossil counterparts which would support the second scenario. In order to assess the maximum possible impact of biofuels on EU refineries we have simulated the second scenario i.e. where refineries fully compensate for lost volumes.

One of the concerns in relation to potential biofuels supply is the limited availability of bio-diesel components in the face of an ever increasing global diesel demand. Starting from a 10% biofuels by energy in EU road fuels in 2020, our scenario assumes no obligation to spread the target equally between gasoline and diesel and a relatively larger penetration of ethanol in gasoline than bio-diesel in diesel. While limiting the ethanol content of the gasoline main grade to 10% v/v (E10), this could be achieved by aggressive introduction of “Flexible Fuel Vehicles” (half of total gasoline vehicle sales in 2020) resulting in about 8 Mt/a ethanol used as E85 in 2020. Bio-diesel components would be essentially FAME with some hydrotreated vegetable oils and a small amount of “Biomass-To-Liquid” (BTL) fuels from EU woody waste material.

These assumptions result in respective average energy contents of 14.4% ethanol in gasoline and 8.3% bio components in diesel. The corresponding demand for bio-diesel components is 21 Mtoe/a (which is challenging from a supply point of view) and 13 Mtoe/a for ethanol.

Results are shown in **Table 14**, compared to the reference 2020 case presented earlier, including the benefit of improved energy efficiency as discussed in *section 7.1*.

Refinery production of road fuel decreases by a total of 34 Mt/a while the diesel/gasoline ratio increases somewhat due to the relatively larger use of ethanol. Plant utilisation is reduced across the board resulting in a significantly lower need for investment.

Refinery energy consumption decreases in both absolute and relative terms as less material is processed and the conversion level is slightly reduced (less light products for the same amount of residual products). Conversely refinery CO_2 emissions decrease by about 10% or 16 Mt/a to 144 Mt/a i.e. bringing them back to the level emitted in 2005.

Table 14 Impact of a low road demand scenario linked to biofuels introduction

Cases including energy efficiency improvements		2020 Reference	2020 Low demand	*Delta*
Crude diet				
Intake		716	676	*-40*
API gravity		35.2	35.5	
Proportion of LS crude		46%	48%	
Sulphur content	% m/m	1.12%	1.04%	
Atm. Residue yield	% m/m	42.9%	42.3%	
Fraction of light products[(1)]		82.2%	81.5%	*-0.8%*
Road fuels demand	Mt/a			
Gasoline		92	79	*-13*
Diesel fuel		256	235	*-21*
Diesel / gasoline ratio		2.8	3.0	*0.2*
		Relative to 2005		
Capital expenditure	G$	62.8	49.3	*-13.6*
Total annual cost[(2)]	G$/a	13.8	9.3	*-4.6*
		Relative to base 2005		
Energy consumption	Mtoe/a	50.3	45.9	*-4.5*
	% of tot. feed	7.0%	6.8%	*-0.2%*
Refinery fuel composition				
Refinery and imported gas		55.1%	59.1%	
Liquid		33.1%	29.9%	
FCC coke		11.8%	11.0%	
CO_2 emissions				
From refineries	Mt/a	160	144	*-16*
	t/t of tot. feed	0.21	0.20	*-0.01*
Total (including burning of fuel products)	Mt/a	2150	2024	*-126*
From refineries	% of total	7.4%	7.1%	*-0.3%*

(1) Gasoils and lighter, also including petrochemicals

(2) Including capital charge, excluding margin effects

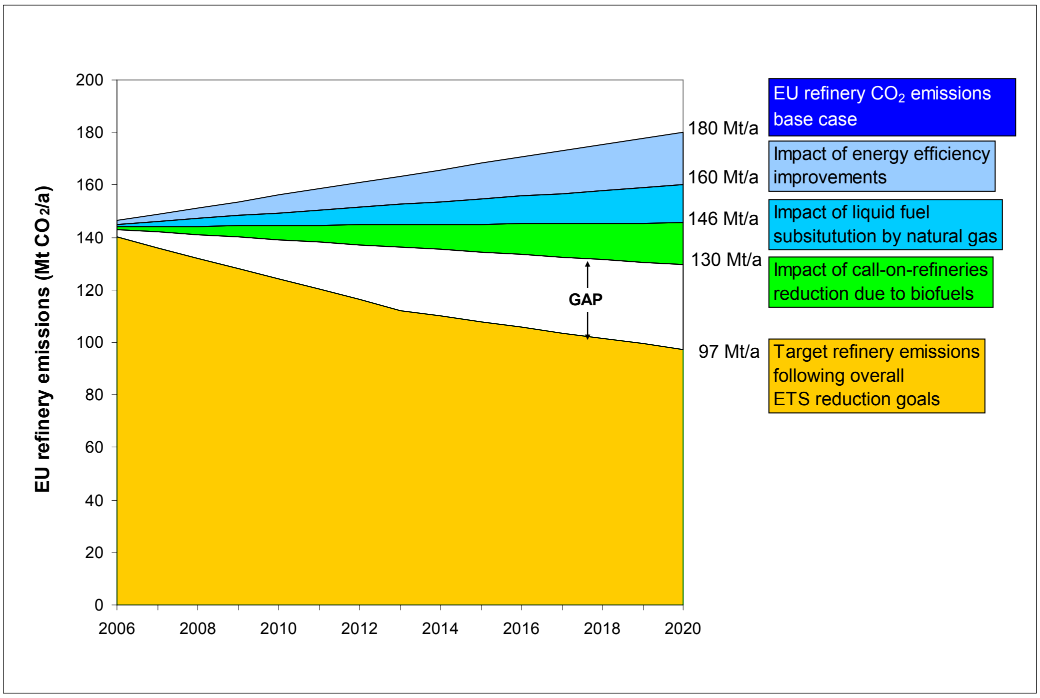
9. CONSIDERATION OF THE EU ETS REDUCTION TARGET

At this point it is interesting to refer back to the EU ETS and compare the foreseen evolution of refinery emissions, including mitigation measures, with the expectations implied by this legislation. **Figure 21** illustrates the gap that is likely to open between expectations and reality.

Applying to EU refineries a reduction target consistent with the overall ETS reduction goals leads to emissions of 97 Mt/a in 2020[3]. Our base case indicates nearly twice that figure at 180 Mt/a (without our additional product quality step-out cases). Energy efficiency improvements could deliver a reduction of some 20 Mt/a and fuel switching another 16 Mt/a (although some of the latter may not result in effective a global emission reduction). This would leave a gap of 49 Mt/a, which would need to be filled by other means failing which the sector would become a net purchaser of emissions even if all emission permits under the target line were allocated free-of-charge.

As we have seen above CCS is unlikely to deliver sizeable reduction before 2020. The only option available to EU refiners will be a reduction of activities. Fully compensating the loss of call-on-refineries caused by biofuels introduction could lead to some 16 Mt/a further reduction (see *section 8*) still leaving a gap of 33 Mt/a which, short of an effective reduction of demand, would need to be compensated by more imports possibly combined with a limited drive towards usage of lighter crudes. These two latter measures would simply displace emitting activities outside Europe and would not result in global reductions.

Figure 21 EU refineries CO_2 emissions trend and EU ETS allowances
(Allowance figures are approximate and for illustration only)



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[3] Assuming a total emission cap of 1720 Mt in 2020 minus 5% new entrants reserve and refining representing 6% of the total

10. CONCLUSIONS

Refiners the world over and in particular in Europe are facing a rapid evolution of their markets in the next 10-15 years. The EU is implementing one of the toughest set of fuel quality specifications while, in the same time frame, the imbalance between middle distillates and gasoline is relentlessly widening. In order to face these changes while still supplying the market, EU refiners will need to invest heavily in a variety of process units that improve product quality and change the shape of the “product barrel”.

In this context, reducing the absolute level of CO_2 emissions from refineries is a tough challenge. New investments and additional processing will inevitably result in higher CO_2 emissions all things being equal.

The mitigating measures available to refiners are limited. Energy efficiency improvement, a constant theme for many years in refineries, still presents opportunities and these will undoubtedly be grasped especially in the current “expensive energy” environment. Replacing what liquid fuel is still burnt in refineries today by natural gas would reduce emissions at the refineries but the question has to be asked whether it would indeed result in global emission reductions. CCS raises many hopes and expectations but will not realistically make a meaningful contribution until the end of the period and into the third decade of this century.

Short of curtailing their level of activities, including reflecting the loss of call-on-refineries resulting from the introduction of biofuels, it is difficult to see how EU refineries will be able to achieve more than a stabilisation of their emissions between today and 2020.

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APPENDIX 1 REFERENCE PRICE SET

North West Europe, 2007 average

All figures in $/t except when otherwise stated

Feedstocks and components

North Sea/Low Sulphur	552
West African	539
Russian	486
Middle East medium sour	517
Middle East sour	502
Condensate	641
Crude input average	524
$/bbl	*71.8*
Chemical Naphtha	665
Natural Gas	512
Atm Residue (North Sea)	402
Ethanol	500
Other Feed average	487
ETBE	824
Jet fuel	692
Middle distillate low sulphur	657
Middle distillate high sulphur	626
Blendstock Import average	671
All Input	530

Products

LPG	628
Ethylene	902
Propylene	859
Butylenes	710
Benzene	1047
Toluene	812
Xylenes	829
Chemical Products average	895
Gasoline EU Premium	687
Gasoline East Europe	687
Gasoline EU Super	696
Gasoline Export (US)	680
Gasoline EU Regular	678
Gasoline average	686
Jet fuel	697
Non Road Diesel	656
Road Diesel North	656
Road Diesel Middle	656
Road Diesel South	660
Road Diesel	657
Heating Oil North	626
Heating Oil Middle	627
Heating Oil South	637
Heating Oil	630
Marine Diesel	631
Diesel & Heating Oil average	648
Fuel Oil 0.6% Sulphur	354
Fuel Oil 1.0% Sulphur	354
Fuel Oil 2.5% Sulphur	347
Fuel Oil 3.5% Sulphur	329
Bunker Low sulphur	347
Bunker High Sulphur	326
Fuel Oil average	338
Bitumen	322
Lubricant base oils	626

APPENDIX 2 PRODUCT QUALITY LEGISLATION AND QUALITY LIMIT TARGETS FOR MODELLING

Quality change steps

Year	Product(s)	Legislation		Shorthand
2000	Gasoline / Diesel	Directive 98/70/EC on fuels quality: Auto Oil 1 phase 1	150/350 ppm S in gasoline/diesel + other specs	FQD: Auto Oil 1-2000
2000	IGO/Heating oil	Directive 1999/32/EC on sulphur in liquid fuels	Heating oil 0.2% S	SLFD: Heating oil 0.2% S
2003	HFO	Directive 1999/32/EC on sulphur in liquid fuels	Inland HFO 1% 1S	SLFD: Inland HFO 1% S
2005	Gasoline / Diesel	Directive 98/70/EC on fuels quality: Auto Oil 1 phase 2	50 ppm S in gasoline/diesel + 35% aromatics in gasoline	FQD: Auto Oil 1-2005
2006-7	Marine fuels	Marpol Annex VI, Directive 2005/33/EC on the sulphur content of marine fuels: sulphur restrictions in Baltic and North Sea SECAs and for EU ferries	1.5% S in marine fuel for SECA & Ferries	IMO: 1.5% S SECA & Ferries
2008	IGO/Heating oil	Directive 1999/32/EC on sulphur in liquid fuels	Heating oil 0.1% S	SLFD: Heating oil 0.1% S
2009	Gasoline / Diesel	Directive 98/70/EC on fuels quality: Auto Oil 2	10 ppm S in gasoline/diesel	FQD: Auto Oil-2
2009	Gasoline / Diesel	Fuels Quality Directive proposal: Non-road diesel specification and diesel PAH limit	8% m/m PAH in road diesel 10 ppm S in non-road diesel	FQD: AGO PAH 8%, NRD 10 ppm S
2010	Marine fuels	IMO: sulphur restriction in SECAs, extended to EU ferries by Directive 2005/33/EC on the sulphur content of marine fuels	1.0% S in marine fuel for SECAs	IMO: 1.0% S SECA
2011	Marine diesel	Fuels Quality Directive proposal: Inland waterways diesel	10 ppm S in gasoil for inland waterways	FQD: Inland waterways GO 10 ppm S
2015	Marine fuels	IMO: sulphur restriction in SECAs, extended to EU ferries by Directive 2005/33/EC on the sulphur content of marine fuels	0.1% S in marine fuel for SECAs	IMO: 0.1% S SECA
2020	Marine fuels	IMO: Global sulphur cap	0.5% S in all marine fuels	IMO: 0.5% S all marine fuels
Step-out cases				
	Marine fuels	*Substitution of all marine fuels by distillates at <0.5% sulphur*		*Marine Fuel to 0.5% S distillate*
	Diesel	*Reduction of PAH to < 2% m/m*		*Ultra low AGO PAH*
	Heating oil	*Heating oil sulphur reduction to <50 ppm*		*Heating Oil 50 ppm S*

Specifications

				Incremental Changes													
			1999	FQD: Auto Oil 1-2000 2000	SLFD: Heating oil 0.2% S 2000	SLFD: Inland HFO 1% S 2003	FQD: Auto Oil 1-2005 2005	SLFD: 1.5% S SECA & Ferries 2006	SLFD: Heating oil 0.1% S 2008	FQD: Auto Oil-2 2009	FQD: AGO PAH 8%, NRD 10 ppm S 2009	SLFD: 1.0% S SECA 2010	FQD: Inland waterways GO 10 ppm S 2011	SLFD: 0.1% S SECA 2015	SLFD: 0.5% S all marine fuels 2020	*Marine Fuel to 0.5% S distillate*
Gasoline																
	Sulphur	ppm	500	**150**	150	150	**50**	50	50	**10**	10	10	10	10	10	10
	Vap. Pres.	kPa	70	**60**	60	60	60	60	60	60	60	60	60	60	60	60
	Benzene	% v/v	5	**1**	1	1	1	1	1	1	1	1	1	1	1	1
	Aromatics	% v/v		**42**	42	42	**35**	35	35	35	35	35	35	35	35	35
	Olefins	% v/v		**18**	18	18	18	18	18	18	18	18	18	18	18	18
Diesel																
	Density	kg/m^3	860	**845**	845	845	845	845	845	845	845	845	845	845	845	845
	Sulphur	ppm	500	**350**	350	350	**50**	50	50	**10**	10	10	10	10	10	10
	Cetane		46	**51**	51	51	51	51	51	51	51	51	51	51	51	51
	PAH	% m/m		**11**	11	11	11	11	11	11	**8**	8	8	8	8	8
Heating Oil																
	Sulphur	% m/m	0.5	0.5	**0.2**	0.2	0.2	0.2	**0.1**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Marine Gasoil																
Inland	Sulphur	% m/m	0.5	0.5	**0.2**	0.2	0.2	0.2	**0.1**	0.1	0.1	0.1	**0.001**	0.001	0.001	0.001
Other	Sulphur	% m/m	0.5	0.5	**0.2**	0.2	0.2	0.2	**0.1**	0.1	0.1	0.1	0.1	0.1	0.1	**0.1**
Inland HFO																
	Sulphur	% m/m	3.5	3.5	3.5	**1.0**	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Marine fuels																
Global cap	Sulphur	% m/m					**4.5**	4.5	4.5	4.5	4.5	**3.5**	3.5	3.5	**0.5**	
SECAs	Sulphur	% m/m					**4.5**	**1.5**	1.5	1.5	1.5	**1.0**	1.0	**0.1**	0.1	
Ferries	Sulphur	% m/m					**4.5**	**1.5**	1.5	1.5	1.5	**1.0**	1.0	**0.1**	0.1	
Model constraints																
Gasoline																
	Sulphur	ppm		**140**	140	140	**40**	40	40	**7**	7	7	7	7	7	7
	Vap. Pres.	kPa		**60**	60	60	60	60	60	60	60	60	60	60	60	60
	Benzene	% v/v		**0.9**	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	Aromatics	% v/v		40	40	40	**33**	33	33	33	33	33	33	33	33	33
	Olefins	% v/v		17	17	17	17	17	17	17	17	17	17	17	17	17
Diesel																
	Density	kg/m^3		**840**	840	840	840	840	840	840	840	840	840	840	840	840
	Sulphur	ppm		**340**	340	340	**40**	40	40	**7**	7	7	7	7	7	7
	Cetane			**49**	49	49	49	49	49	49	49	49	49	49	49	49
	PAH	% m/m		**11**	11	11	11	11	11	11	**7**	7	7	7	7	7
Heating Oil																
	Sulphur	% m/m		0.48	**0.18**	0.18	0.18	0.18	**0.09**	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Marine Gasoil																
Inland	Sulphur	% m/m		0.48	**0.18**	0.18	0.18	0.18	**0.09**	0.09	0.09	0.09	**0.0007**	0.0007	0.0007	0.0007
Other	Sulphur	% m/m		0.48	**0.18**	0.18	0.18	0.18	**0.09**	0.09	0.09	0.09	0.09	0.09	0.09	**0.09**
Inland HFO																
	Sulphur	% m/m		3.2	3.2	**0.9**	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Marine fuels																
Global cap	Sulphur	% m/m					**4.2**	4.2	4.2	4.2	4.2	**3.2**	3.2	3.2	**0.4**	
SECA	Sulphur	% m/m					**4.2**	**1.4**	1.4	1.4	1.4	**0.9**	**0.9**	**0.09**	0.09	
Ferries	Sulphur	% m/m					**4.2**	**1.4**	1.4	1.4	1.4	**0.9**	0.9	**0.09**	0.1	

APPENDIX 3 MARINE DISTILLATE "DMB" SPECIFICATION

The values listed below were used as model constraints.

Property	Units	Minimum	Maximum
Density	kg/m^3	800	900
Sulphur	%m/m		0.3[(1)]
Viscosity	Cst @40°C		11
Pour Point	°C		0
Cetane		40	
Carbon residue	%m/m		0.3[(2)]

[(1)]Average taking into account general 0.5% cap and 0.1% limit in SECAs
[(2)]Modelled indirectly through individual component limits

APPENDIX 4 EU-27 DEMAND, TRADE AND CALL-ON-REFINERIES

EU-27 Demand

Year =>	2000	2005	2010	2015	2020
LPG	18.8	20.0	20.4	19.8	18.7
Ethylene	21.2	23.7	24.2	24.2	25.4
Propylene	14.1	15.2	15.4	15.9	16.7
Butylenes	2.2	2.7	3.0	3.4	3.9
Benzene	7.9	8.5	9.2	10.0	10.8
Toluene	2.2	2.3	2.3	2.4	2.4
Xylenes	2.6	3.3	4.1	5.1	6.4
Chemical Products total	50.3	55.7	58.2	60.9	65.6
Gasoline EU Premium	108.1	104.4	94.2	88.0	86.6
Gasoline East Europe	6.6	0.0	0.0	0.0	0.0
Gasoline EU Super	6.2	4.6	3.1	2.9	3.1
Gasoline Export (US)	0.0	0.0	0.0	0.0	0.0
Gasoline EU Regular	10.4	6.3	2.9	2.7	2.6
Gasoline total	131.3	115.3	100.2	93.6	92.2
Jet fuel & kerosene	51.9	56.5	65.7	73.0	76.8
Non Road Diesel[(1)]	1.4	1.2	0.0	0.0	0.0
Road Diesel	152.7	186.7	229.8	243.0	236.6
Heating Oil	95.2	92.9	78.8	78.6	78.2
Marine Diesel	13.7	12.3	12.5	8.2	8.3
Diesel & Heating Oil total	263.0	293.1	321.1	329.8	323.1
Fuel Oil 0.6% Sulphur	0.5	0.5	0.4	0.4	0.3
Fuel Oil 1.0% Sulphur	40.7	39.8	31.7	27.8	26.7
Fuel Oil 2.5% Sulphur	6.0	0.0	0.0	0.0	0.0
Fuel Oil 3.5% Sulphur	16.1	4.7	4.2	3.8	3.5
Marine fuel (SECA)	0.0	0.0	21.6	23.4	24.2
Marine fuel (non SECA)	36.3	46.5	34.3	36.9	38.0
Fuel Oil total	36.3	46.5	34.3	36.9	38.0
Bitumen	19.7	20.2	21.1	22.0	22.2
Lubricant base oils	6.9	6.1	6.3	6.3	6.3

(1) As separate grade

Trade

Year =>	2000	2005	2010	2015	2020
Gasoline Export	22.1	22.1	22.1	22.1	22.1
ETBE Import	1.7	1.7	1.7	1.7	1.7
Kerosine Import	15.0	15.0	15.0	15.0	15.0
Distillate Import LS	10.0	10.0	10.0	10.0	10.0
Distillate Import MS	10.0	10.0	10.0	10.0	10.0

Call on Refineries

Year =>	2000	2005	2010	2015	2020
LPG	18.8	20.0	20.4	19.8	18.7
Chemical Products total	50.3	55.7	58.2	60.9	65.6
Gasoline total	153.4	137.4	122.3	115.7	114.3
Jet fuel & kerosene	51.9	56.5	65.7	73.0	76.8
Diesel & Heating Oil total	263.0	293.1	321.1	329.8	323.1
Fuel Oil total	36.3	46.5	34.3	36.9	38.0
Bitumen	19.7	20.2	21.1	22.0	22.2
Lubricant base oils	6.9	6.1	6.3	6.3	6.3