The European Refining Blues

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Topic: Supply/Production
Tags: europe, refining [list all tags]

This is a guest post by Stephen Bowers (TOD user carnot) who works for Evonik, a major chemical company based in Germany. Stephen is a petroleum chemist with over 30 years experience and started his career as a mud logger drilling oil wells.

Oil refining in Europe enters a new phase as the combination of emissions legislation and dieselisation of transport fuels demand really starts to bite. In the past months we have seen the rather muted bankruptcy of a major independent refiner, Petroplus, which was set up in the last decade by one Thomas O'Malley, who had previously set up the independent and very successful refining group Valero. Petroplus, it would appear, tried to emulate the strategy of Valero, and in Europe purchased 7 refineries of rather mixed capabilities at relatively low cost: two in France (ex Shell), two in the UK (ex BP and Phillips), one in Germany (ex Exxon), one in Belgium, and one in Switzerland. By the time of the bankruptcy announcement Petroplus had shuttered two of the refineries: one in the UK and one in France.

How did it all unravel?

In this article, the changing landscape experienced by European refiners will be explored to help understand how a business that was profitable a few short years ago became much less so.

A New Market Environment in Refining

In 2005, refining had become suddenly profitable, and refining oil had thrown off the decades trend of low margins and the emergence of capacity limitations and strong end use demand had turned it into a a money maker. I remember going to several refining conferences in 2005 and I noticed an unduly large number of investment bankers and finance types in the audience - nouveau experts in refining finance. Whispers were heard at lunch of, "How about locking in that refining margin profit?" When they found out that I did not actually work for a refinery, the suits moved on to find someone who did. It was almost surreal watching these financiers circle and entrap their prey; a bit like bloodsucking leeches in a jungle.

Total produced this slide at the European Refining Conference that was held recently in Paris. Units are in $/mt. To convert to barrels divide by 7.3. You do not need much of a calculator to work out that the margin is 2-3% of the crude price: thin to non-existent. See Figure 1:

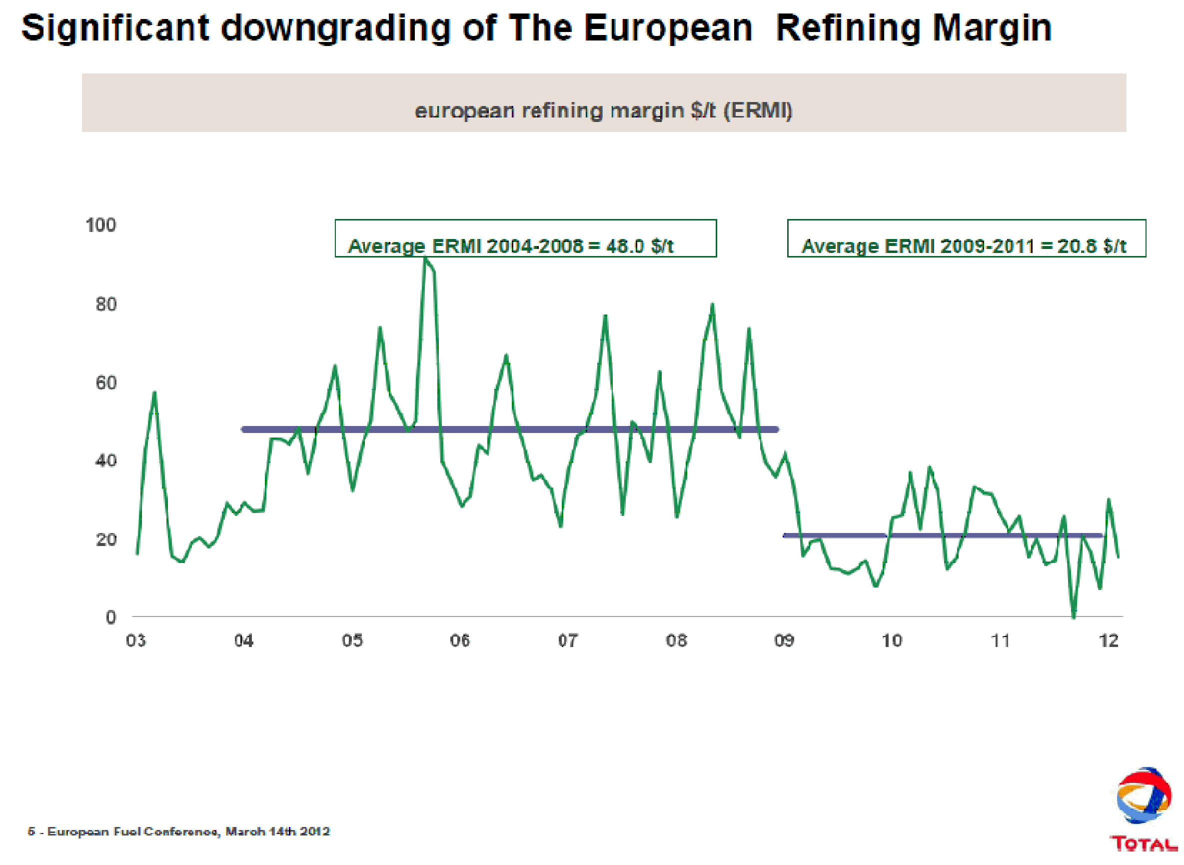

Figure 1: European Refining Margins

Meanwhile, a few wily refiners decided to cash-up by doing a bit of housekeeping. BP and Shell managed to off-load a number of not so good assets to debt financed buyers who, like lambs to the slaughter, thought the good times were here to stay. Then in 2008 the wheel came off the wagon and margins fell back to the long-term trend, but meanwhile, the price of oil had doubled. Needless to say, many of the new guys found that oil refining was not so easy after all. The ever publicity seeking Sir Richard Branson of Virgin Group fame, not one to miss any opportunity for self- aggrandizement, duly announced that it was time to buy an oil refinery, and take on the big boys at their own game. He must have wised up because like a lot of his ideas, it came to zippo and he probably saved himself a fortune.

As I complete this article, we have several recent sales of refining assets both side of the Atlantic. Gunvor purchased the Petroplus Antwerp refinery and Vitol-Atlasinvest have purchased the Cressier Switzerland refinery. Neither of these assets are outstanding. Meanwhile, Delta (of airline fame) has purchased the Conoco Phillips Trainer Refinery via their Monroe subsidiary. Carlyle are in talks to purchase the Sunoco Philadelphia refinery. I would not count either of these refineries as outstanding and despite Delta's claims that they will save $300 million per year by investing $100 million (+ purchase price of refinery) to maximise jet fuel production, I remain somewhat sceptical for this reason: to save $300 million on 185 kbd per day would imply a margin increase of $4.43 per barrel. If it were that easy, why has Conoco not already done it? The payback would be in four months. Alas, Delta is in dream land. The refinery capacities are in the table extracted from the Oil and Gas Journal Refinery survey January 2012.

http://www.bloomberg.com/news/2012-04-30/delta-air-said-to-near-accord-t...

http://www.bloomberg.com/news/2012-04-23/sunoco-in-talks-with-carlyle-on...

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
Valero Energy Corp.—Ardmore	91,500	32,000	—	—	[1]30,576	[3]21,679	[1]12,000	[1]26,500 [5]28,000 [8]32,000	[2]7,012	—	—	[3]7,000	—	—	[1]26.0 [4]26.0	—	243	11,000
Wynnewood Refining Co.—Wynnewood	52,500	15,500	—	—	[1]18,500	[3]13,000	[1]5,500	[1]12,000 [9]11,700	[2]4,000	—	—	[3]3,500	—	—	[1]9.0	—	—	5,000
Total	**456,000**	**127,500**	**23,100**	**—**	**108,376**	**78,679**	**17,500**	**297,900**	**24,012**	**2,400**	**—**	**33,900**	**—**	**—**	**107.8**	**1,150**	**441**	**16,000**
PENNSYLVANIA																		
American Refining Group—Bradford	10,000	—	—	—	—	[1]1,800	—	[1]3,500	—	—	—	[3]600	2,600	—	—	—	—	—
ConocoPhillips—Trainer[4]	185,000	78,700	—	—	[1]48,400	[3]48,800	c[4]21,500	[1]51,900 [5]25,800 [8]38,300 [12]14,200	[2]11,800	—	—	—	—	—	—	—	160	—
Sunoco Inc.—Marcus Hook[Q]	175,000	26,400	—	—	[1]93,000	[1]15,600	—	[1]36,000 [12]12,000	[1]10,000	—	[1]19,200 [3]2,400	—	—	[1]2,600	[1]6.0	—	—	—
Sunoco Inc.—Philadelphia[Q]	330,000	157,400	—	—	[1]113,500	[1]68,000	—	[1]85,600 [5]78,000	[2]16,700	—	[1]3,700 [4]10,000	[1]7,300	—	—	—	—	—	—
United Refining Co.—Warren	66,700	27,000	—	—	[1]23,000	[2]16,000	—	[2]20,000 6,000	[1]3,500	[1]1,000	—	[3]6,800	—	—	—	—	—	12,000

Table 1: Pennsylvania Oil Refineries and capacities (click image for more readable version)

The Influence of Biofuel Mandates

About the same time as the refining margins peaked, Europe got "biofuel fever". The old arguments surfaced. Climate change, energy independence, carbon emissions, green transport, but no mention of Peak Oil anywhere in sight. The farm lobby was not slow to catch on, and we saw a massive push to biodiesel followed by a later push to ethanol under the guise of the renewable transport fuel obligations (RTFO). Biodiesel was competitive with mineral diesel we were told. Well fools and their money are soon parted, and investors large and small raced headlong into the shark-infested market of biodiesel. I remember in 2005 negotiating a tank storage deal with a long-term supplier. He was well pleased. He had signed a deal with a large biodiesel producer. I was intrigued. It was a 15-year deal and 250 kta throughput. Those are big numbers. I thought, What do these guys know that I don't? Am I missing something? I asked sort of matter of factly where the vegetable oil was going to come from. "Imported from wherever is cheapest," was the reply. "Really", I said. Good luck, I thought. My cynicism was not wrong. The shiny new state of the art biodiesel plant started up and then shut down, and then went bust, taking a lot of investors' money with it, and leaving Barclays bank with a shiny new unprofitable biodiesel plant (current European biodiesel capacity is about 20 million tonnes per annum - the actual production is not even half of that figure). This plant that ran up debts of over $158 million was disposed of for $15.8 million and its future is still unclear. So much for the 15-year storage contract. Well, currently mineral diesel nudges $1000 pmt and biodiesel is close to $1300 pmt, and as I write we continue to hear the cries of, "All we need is a subsidy, a mandate, or higher oil prices or better still all three, and we will be profitable." Well, it now looks as if they will have one wish granted as the EU RTFO (renewable transport fuel obligation) mandates 7% biodiesel into the diesel/gas oil pool, much to the chagrin of any driver who is wise enough to know that it is a truly lousy product and an even worse idea. Figure 2 demonstrates quite eloquently the capacity and production of European biodiesel. Only mandates are keeping biodiesel alive in Europe, paid for by the long suffering consumer at the pump. If we really have to use vegetable oils(or animal fats) in fuels, then hydrogenation is THE way to go without doubt. On a variable cost basis, there is little to choose between FAME and HVO. On quality and handling there is no comparison.

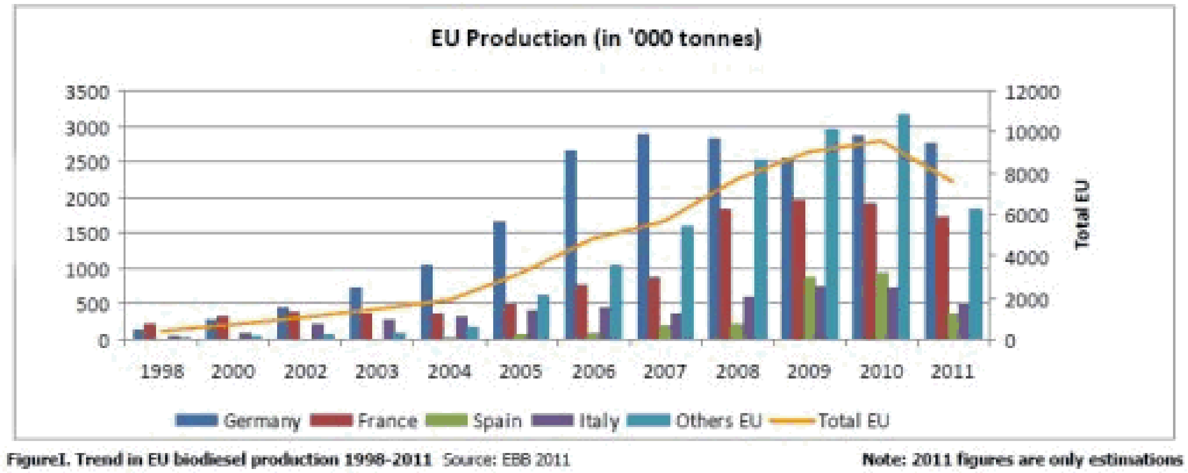

Figure 2: European Biodiesel Production and capacities
Actual source here- http://www.ebb-eu.org/stats.php

The ethanol lobby raced to catch up and now most of European gasoline has some ethanol blended into it, but it varies from country to country. The Germans, who like to think they are green, adopted a 10% ethanol requirement in gasoline in 2011 which went down like a Lead Zeppelin (as opposed to Led Zeppelin). German motoring organisation were up-in-arms and motorists shunned the new grade, paying over the odds to buy 98 octane super plus instead of 10% ethanol gasoline, and causing local fuel shortages of the premium grade that only made up 3% of normal sales. They, the Germans, were not going to use that "green fuel" in their pride and joy, and frankly I do not blame them.

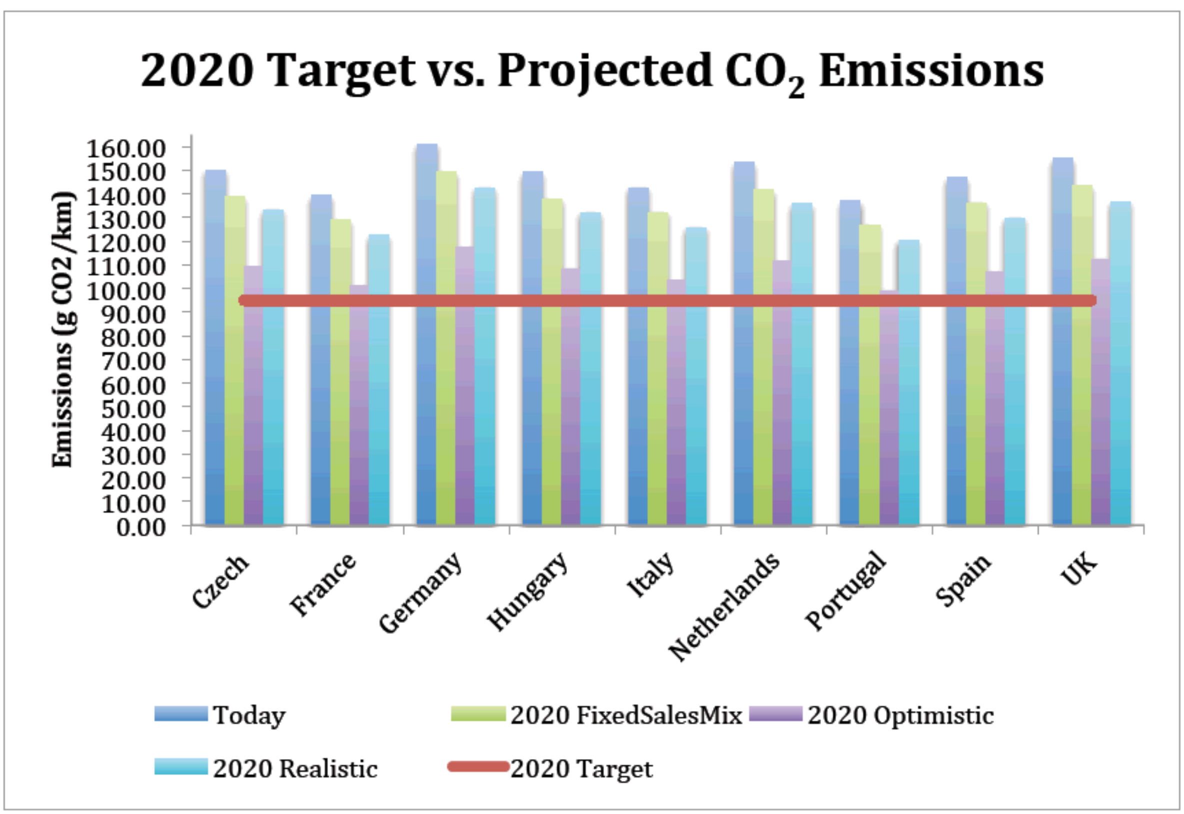

Figure 3: EU projected light vehicle carbon emissions and target
Source: [3 Bhatt Meeting EU Standards 2010]()

Switch From Gasoline to Diesel

More pain was yet to come as the the high prices did, more than anything, modify consumers' habits. A steady shift away from gasoline vehicles to diesel, and improving technology has drastically reduced fuel consumption over the past decade in Europe. By 2020, the fleet average emissions target will be 95 g carbon dioxide per km, or at least that is what has been legislated. The penalty is a levy on every vehicle that exceeds the fleet average, based on its carbon emissions. Though only few cars can achieve this at present, there are more and more getting closer and closer. As a result it looks as if diesel demand is close to peaking and gasoline demand is in continuous slow decline decline. See the following slide, Figure 4 from Europia to explain this point.

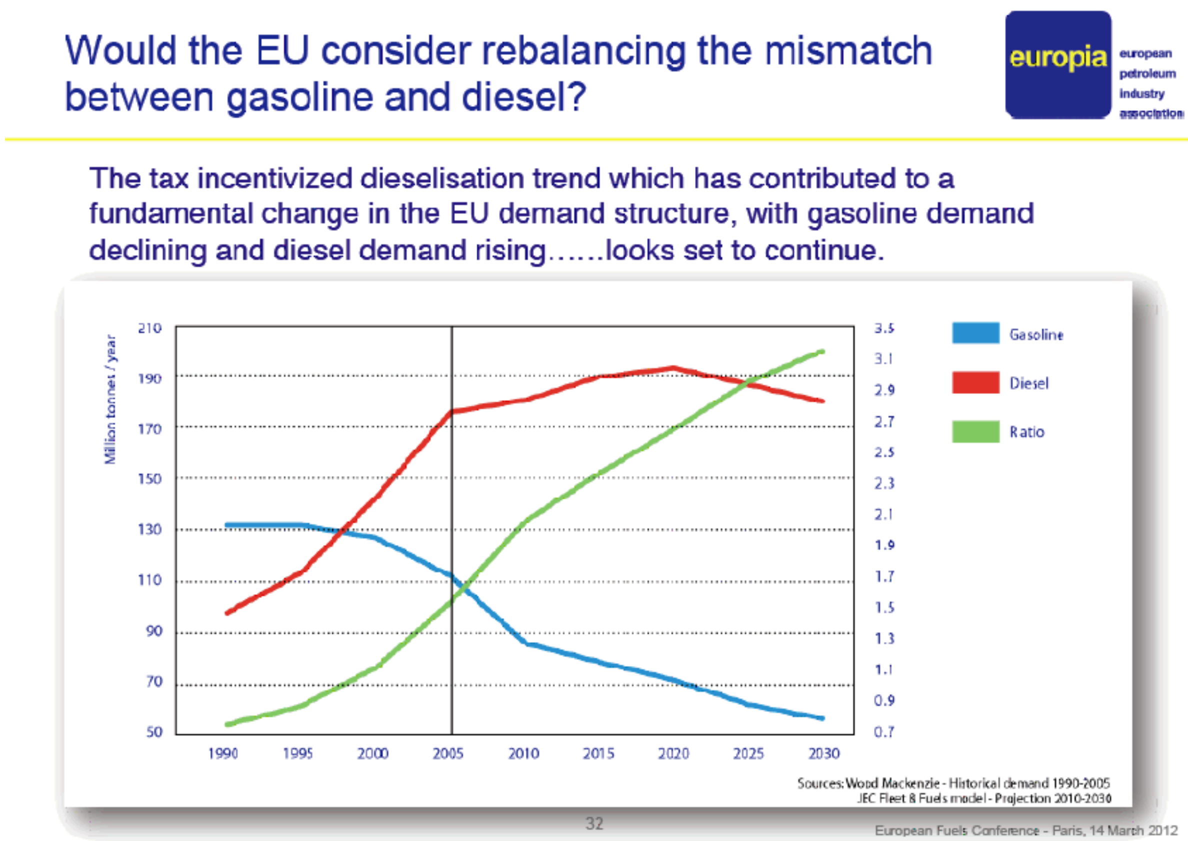

Figure 4: EU gasoline diesel balance

This can be seen in the sales of diesel cars in this slide Figure 5, again courtesy of Total.

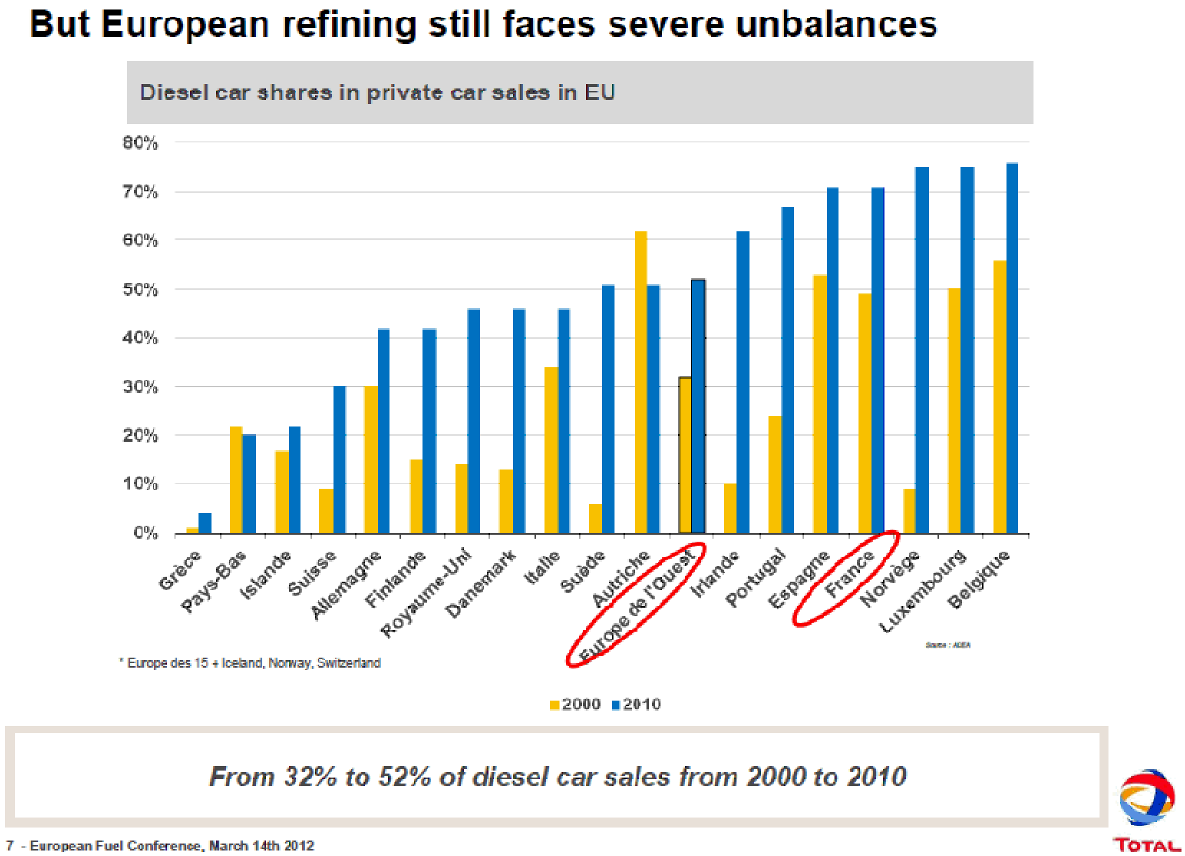

Figure 5: Distribution of Diesel- Gasoline vehicle sales in EU

By 2011 the refining margins were also causing pain. Refinery sales, joint ventures, and closures were all on the cards. Re-incarnations were also possible as ConocoPhillips managed to sell the shuttered Wilhemshaven refinery to a Dutch Investor (good luck). Lyondell announced their 2007 acquisition Berre refinery was to close and Total closed one refinery and severely reduced capacity at another. Shell sold two more refineries, Stanlow and Heide, and announced the closure of Harburg. Ineos sold part of their Grangemouth refinery to Sinopec and Tamoil shut Cremona in Italy. Petroplus meanwhile shuttered Reichstett. Phew. We were not done yet. Valero bought the Chevron Pembroke refinery and Rosneft purchased the 50% share of Ruhr Oel that was owned by PDVSA. Total placed Lindsey oil refinery up for sale as did Murphy who put their Milford Haven refinery up for sale as it announced that it wanted to get out of refining. There is more, but I think most readers will get the idea - refining in Europe is not a good business. It never was a good business, and is never likely to be a good business.

The slide Figure 6 gives a snapshot of the situation but it is a moving target. Expect it to get worse, not better.

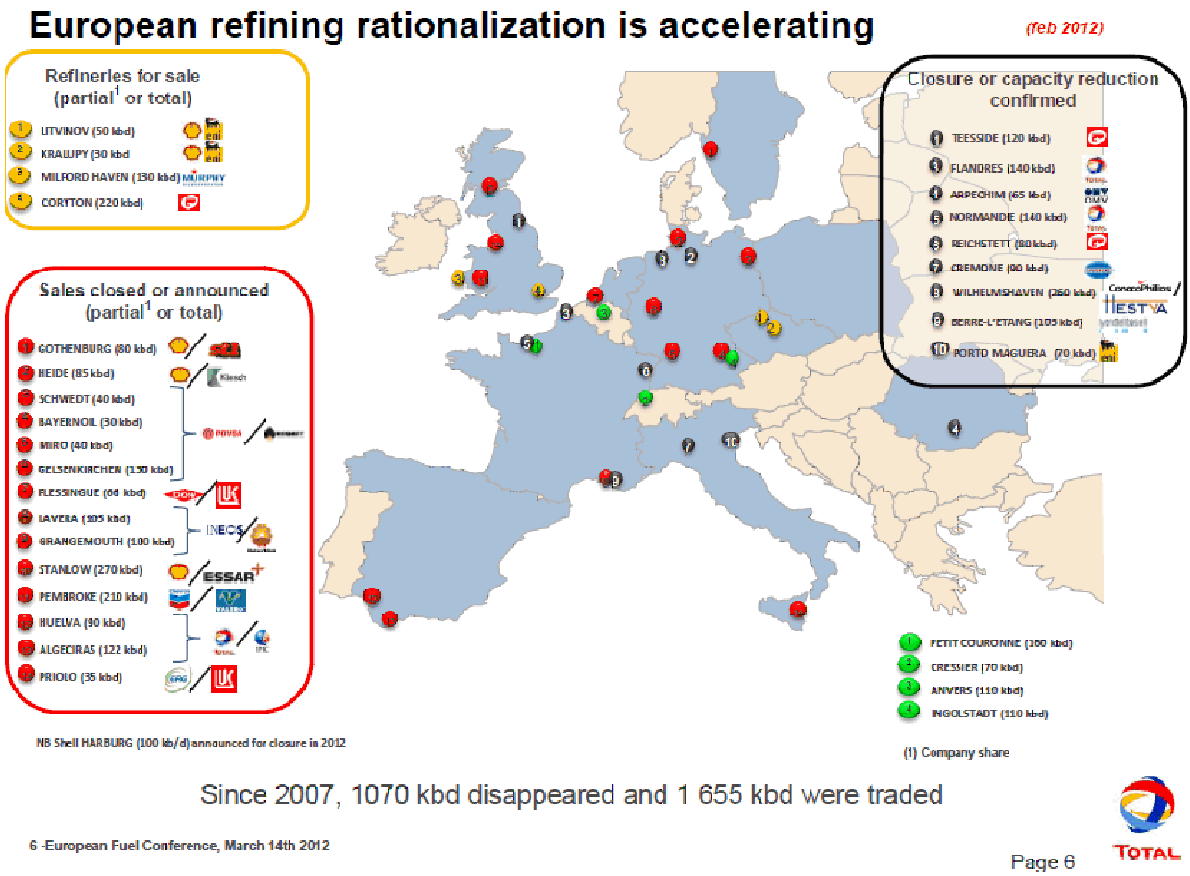

Figure 6: EU refinery sales and closures

The Source of Pain for European Refining

What is wrong? What has happened? The malaise in European refining has not happened overnight. The reasons are deep rooted and come from a number of causes:

- Lack of profitability and therefore under-investment over decades
- High end use pricing due to taxation making up more than 50% of retail cost of transport fuels The refiners have been unpaid tax collectors.
- Changing fuel specification standards, especially with respect to sulphur and aromatics
- Change in product mix which does not now fit the historic refinery configuration
- Growing US gasoline exports making the European gasoline surplus more and more difficult to dispose of
- Biofuel blending especially with ethanol into the gasoline pool
- Carbon Emissions and ETS (emissions trading scheme)

Put together, the causes have made for a miserable 2011 and many refiners are either losing money or are barely profitable, and this is before they start paying for carbon emissions. See Figure 7 Courtesy of Europia.

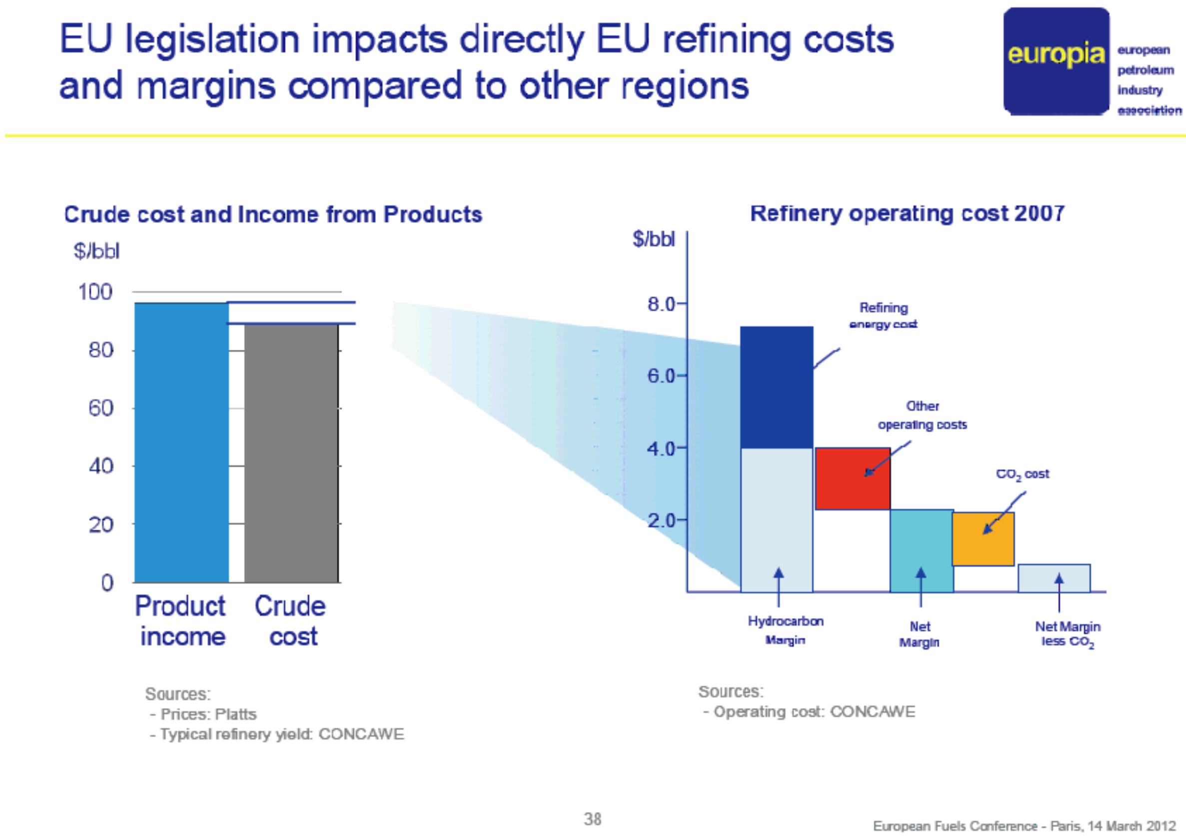

Figure 7: EU refining margin cost structure

Figure 7 ably demonstrates the difficulty with refining margins. The gross refining margin is the product costs less the cost of crude and currently they range from $1-10 per barrel of crude processed, depending on the refinery. Out of the gross refining margin comes the energy costs and the fixed and variable costs, depicted above as the other operating costs. The fixed costs are wages and the like and the variable costs the catalysts and consumables to operate the refinery. What is left is the net cash margin which for this example is about $2 per barrel. As you will also see, energy is now making up a significant part of the cost structure. You do not have to be too clever to realise that with crude at $100 per barrel and something like 7% of the crude burned as energy, the cost per barrel processed is about $7 +/-. Further pain is about to be applied in Europe as the EU in all its wisdom moves towards charging for carbon emissions. Very roughly refiners will have to pay for about 30% of their emissions, the rest being covered by allowances. I am not against efforts to reduce carbon emissions, far from it, but this will be another nail in the coffin for European refiners and more and more fuels production will be off-shored. A prime example is India which is building refineries that will export finished fuels to Europe. India will import oil, refine it and sell it on and meanwhile claim that they should not be bound by carbon emission limits. Hmm, I am not sure if I buy into this. Likewise Saudi Arabia will be massively expanding its refining base, with some of the middle distillate product being targeted at Europe.

Diminishing Margins from Lower Product Sales Flexibility

It is worth noting where the money is made and where the money is lost, and the best way of demonstrating this is in the crack spread, that is the margin made or lost per barrel of finished product in relation to the crude oil price. The crack spread can be constructed for any crude oil if the price of the oil is known and the product prices are known. It is fairly obvious from the graph that if the oil barrel was refined into just jet-kerosene and diesel-gas oil then there would be a shed load of money to be made. But life is not that easy. Fifteen years ago a cocky young accountant said to me that my job marketing aromatics was easy. "Buy low and sell high. Nothing to it". My reply was simple. "There is the phone, show me how its done". He did not accept the challenge and then went on to work for EMI, who went bust (Ha, ha). Refining oil is a capital intensive volume business. Size matters in refining, but that is only part of it. When a barrel of oil is refined one only have limited control over the yield of each product. Though one might wish to produce only jet and diesel, you will not by choice also produce some LPG, naphtha, gasoline and fuel oil; that is the way it is. LPG is typically 3-5% but fuel oil can be 20-40% dependent on the crude, or even higher in a few cases. Minimising the fuel oil production has been a goal for some time and the results have been good in so much as there has been a downward trend in fuel oil production. This comes at a price as either the fuel oil is coked or hydrogen is added to improve its processability, known in the business as carbon out or hydrogen in which I will discuss later. See Figures 8 and 9 and Table 2 below.

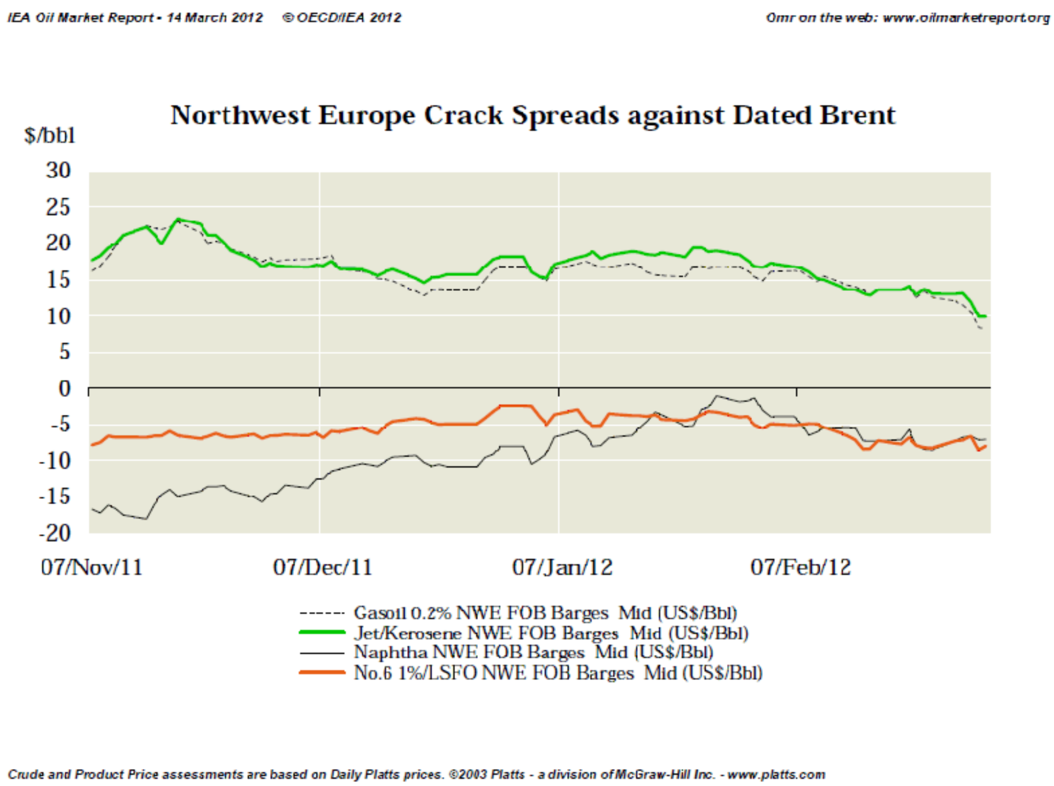

Figure 8: IEA OMR calculated crack spread published April 2012

For licensing reasons the IEA does not publish gasoline pricing in its crack spread model. See below for a fuller picture. Gasoline margins show the typical summer spike.

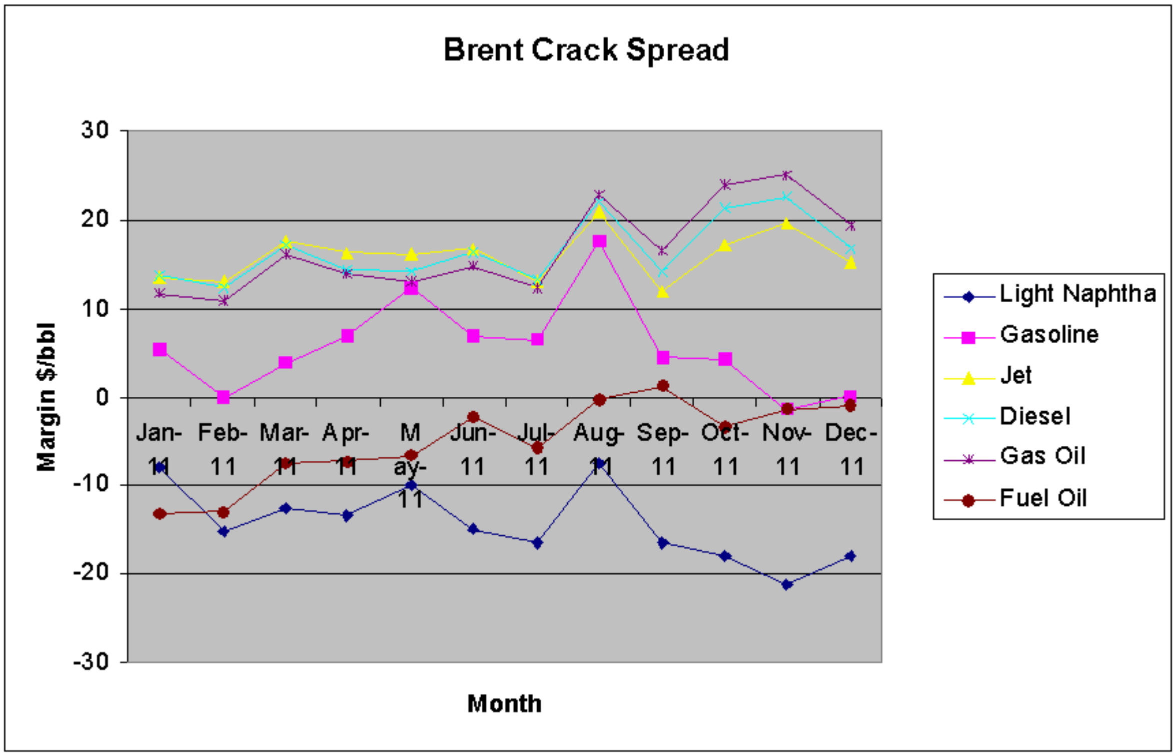

Figure 9: Brent Crack Spread for 2011
Source: Pricing data from Platts monthly averages

Here is the crack spread for 3 well-known crudes for December 11 (2011)

Products	Density	bbl/mt	Price $/bbl	Crack Brent	Crack Arab Lt	Crack Arab Hvy
LVN	0.654	9.617	90.748	-17.962	-17.212	-11.112
Gasoline	0.745	8.442	108.829	0.119	0.869	6.969
Jet Kero	0.793	7.931	123.767	15.057	15.807	21.907
Diesel	0.840	7.487	125.498	16.788	17.538	23.638
Gas Oil	0.860	7.313	128.015	19.305	20.055	26.155
Fuel Oil	1.037	6.065	107.749	-0.961	-0.211	5.889

Table 2: Crack Spread for various crudes for Dec 11
Source data for Pricing is Platts and OPEC monthly bulletin.

As can be seen, the margins are significantly better for Arab Heavy - but this excludes the higher cost of refining and the much more complex refinery that will be required to refine this oil; the crack spread does not reflect the yield. Naphtha was a loser for all crude types and gasoline was far from good. The middle distillate margins made the money. Up until about 2010, Europe relied on disposing of excess gasoline to the US, but that outlet is now closed as the US becomes long on gasoline (at least for the moment).

The common belief is that the light sweet crudes, such as Brent, carry premium prices, which in principle was true in the past but may not be the case now. In January this year, Saudi Aramco sold Arab Light to European customers at a minimal discount of $0.35 per barrel to the Brent price. Suddenly, a 32 API medium sulphur crude has become more valuable than a light 38 API sweet crude. It all comes down to the yield of middle distillates as opposed to light distillate. Naphtha has become a millstone in Europe as ethylene crackers have reduced rates and have looked at ways to increase feedstock flexibility. This has placed particular pressure on those refiners that did not have an in-house outlet for the light naphtha and sold it on the spot market to European crackers. Much of the light naphtha has relatively poor characteristics for gasoline blending and refiners do not want to depress the gasoline price any further. Moreover our new found love affair with ethanol has reduced blending options still further, even putting pressure on iso-pentane blending (C5 isomerate). The obvious way out is therefore to process crudes with less light naphtha and gasoline components and Aramco has not missed this point. In my refinery model in all cases Arab Light crude produces the same or better refining margins than Brent in the EU. See Figure 10:

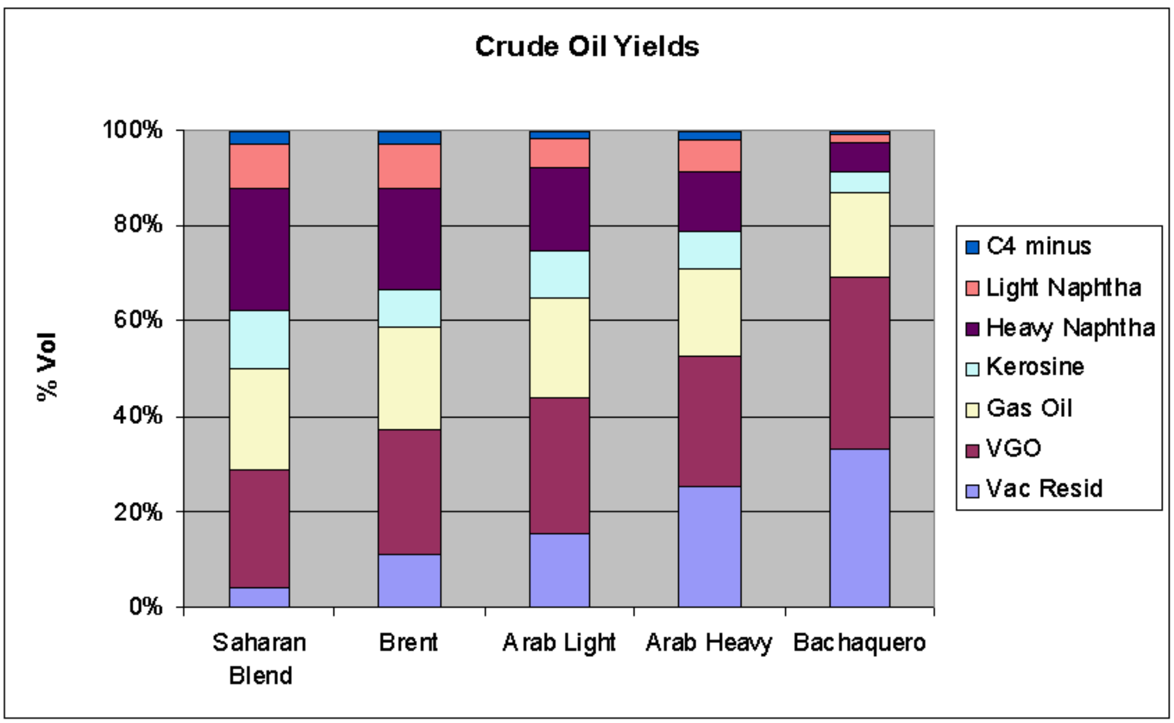

Figure 10: Crude Oil Yields
Source: Modern Petroleum Technology - Institute of Petroleum

For comparative purposes, the Atmospheric Residue or reduced crude is the sum of the VGO and Vac Resid. The sum of kerosene and gas oil make up the middle distillate fraction. This table is representative of the yields after atmospheric and vacuum distillation and before further processing.

With current trends, things will not change any time soon and they could possibly get worse. Several years back the UK Energy Institute magazine ran an editorial that 30% of the European refining capacity could be threatened within the next five years. Few readers took much notice and probably even fewer believed it. But there is little hope for optimism at the present time and the spectre of carbon emission fees might just be the tipping point that sends refiners to look elsewhere. Increasingly, it looks as if Europe will import more and more jet and diesel from the Russia, the Middle East, and India as politicians forge ahead with ill-conceived emission standards and renewable fuel policies in the misguided belief that this is the green way forward.

Static European Refinery Configurations

Looking into the European refining landscape as I do, one sees that the refining base is essentially 40 to 50 years old; past its best, to put it mildly. It expanded rapidly in the 1960s and 1970s and gasoline production was the order of the day, i.e. Fluid Catalytic Cracking and Alkylkation units, coupled with the ubiquitous catalytic reformer for aromatics and hydrogen production. A good example of this is in the diagram, Figure 11, below of the Petroplus Reichstett refinery, which was closed even before they were insolvent. The FCC is a carbon out conversion unit. Coke is deposited on the catalyst which is combusted to produce process heat in the regeneration step.

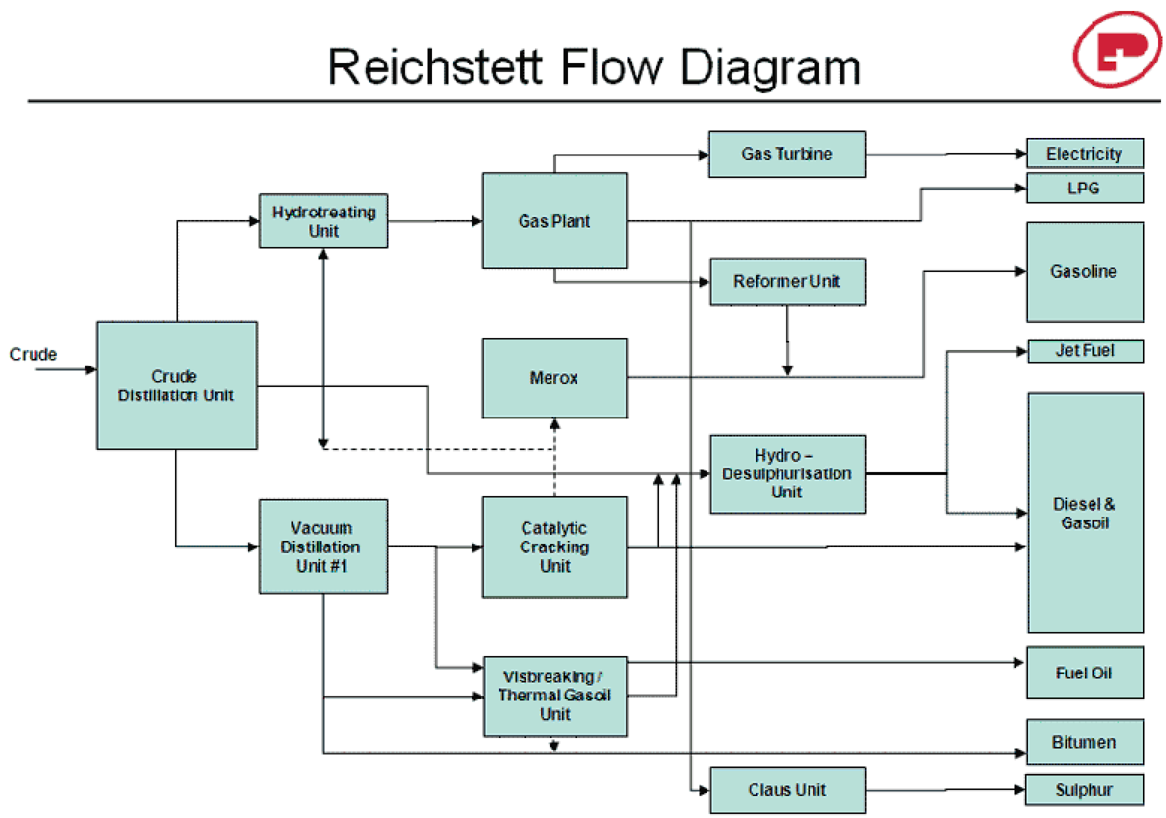

Figure 11: Reichstett Refinery "Classic EU configuration"
Source: Petroplus website before insolvency.

In the 1980s we saw a developing trend towards hydrocracking, and some (a handful) coker units were installed to help minimise fuel oil production. All hydrocrackers in Europe are operated in a middle distillate mode to maximise jet and diesel production. Only minimal gasoline is sought as hydrocrackate gasoline has a low octane number and must be blended with other high octane components. Hydrocrackate diesel and jet do not suffer from this problem and are excellent blend components. Figure 12 is the new configuration for the Repsol Cartegena refinery which has just had a major revamp with a new 100 kbd CDU, a 46 kbd Hydrocracker and a 53 kbd Coker. The original refinery was basic and uneconomic. $3.5 billion of investment will make this a refinery amongst the best in Europe and produce in excess of 50% of the crude charge as middle distillates, which is very impressive by any standard. Note there is no gasoline production in the new part of the refinery. This is a hydrogen addition and carbon rejection set-up. The hydrocracker adds hydrogen (hydrogen in) to the feedstock to saturate olefines formed during cracking and saturate the aromatic rings. Coking is a carbon rejection process that rejects carbon as coke in the residue processing step. The existing CDU is in the white box. Total CDU capacity will be 11 mt of 220 kbd, processing a medium heavy crude.

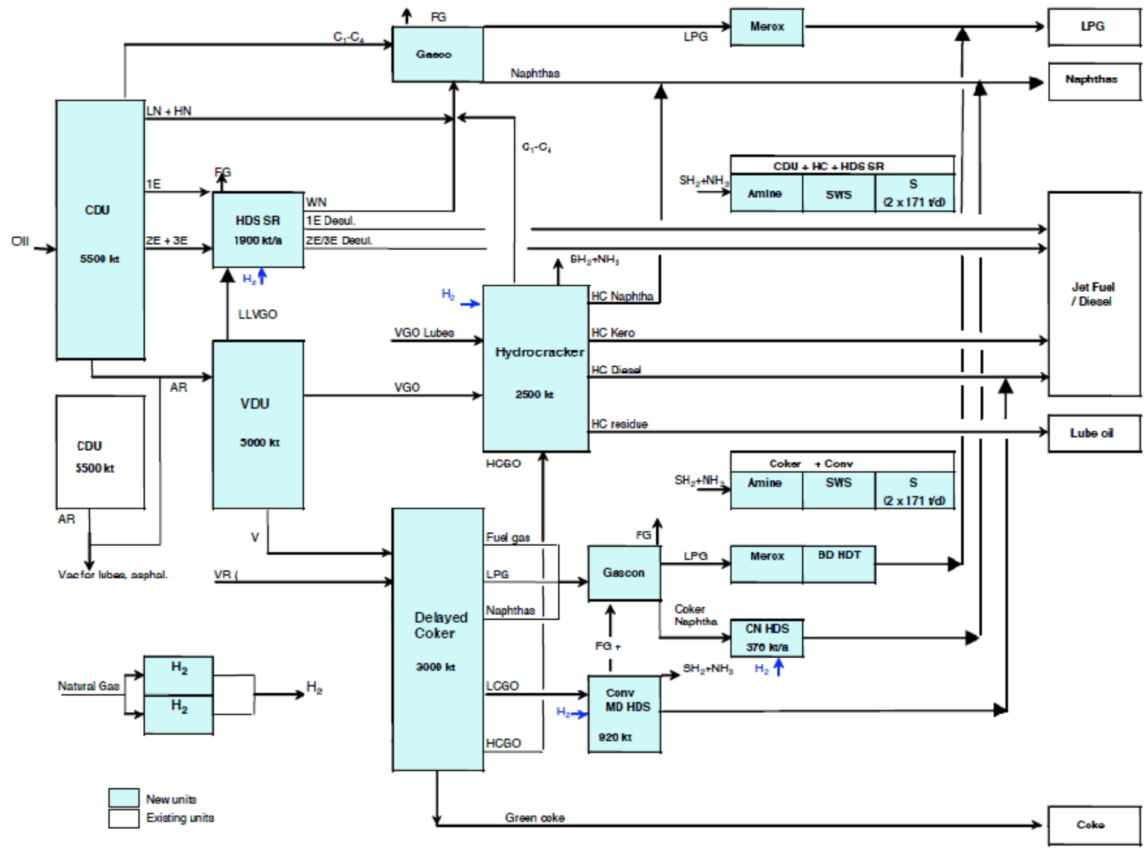

Figure 12: Repsol Cartegena Refinery Expansion
Repsol Carteqena refinery expansion - Facing the Future of Refining Gonzalo 2008

More detail on the Cartegena expansion can be obtained here.

Link http://www.google.com/url?sa=t&rct=j&q=cartegena%20coker%20and%20hydrocr...

or

http://www.onepetro.org/mslib/servlet/onepetropreview?id=WPC-19-0256

This link costs $10, so try the other link first.

By reducing the hydrocracker severity, it is possible to reduce the hydrogen consumption. Another neat trick is to operate in an even milder mode, which allows a high throughput of vacuum distillate, some of which is merely hydrotreated and desulphurised and a product called unconverted oil (UCO) or hydrowax is produced. Hydrowax is essentially treated vacuum gas oil (VGO) and it can be used either as ethylene cracker feed or cracked in a Fluid Catalytic Cracker. In both cases the results are better than untreated VGO. It will also soon find an outlet in low sulphur marine diesel, due to tighter sulphur specifications for marine fuels.

When Hydrowax is used in an FCC there are a number of tweaks available. Turning the severity down produces a greater volume of light cycle oil (FCC diesel) which can be blended into the diesel pool. It is not the best quality but is a useful extender if blended with hydrocrackate diesel. Hydrowax cracks better because some of the aromatic rings are saturated to naphthenes which can then be opened by the FCC catalyst. Another option is to increase the FCC severity and overcrack to C3 and C4 olefines. The real clever approach is to do both. Shell has a FCC process called MILO which stands for Middle Distillate Light Olefines. In this process the severity of the FCC is low towards hydrowax which maximises LCO, and some of the FCC naphtha stream is recycled back for over-cracking to light olefines, hence the term MILO. There are a number of similar competing processes of this type, and FCC naphtha overcracking is becoming increasingly popular. This approach has been adopted at the new Saudi Aramco Total refinery that is being constructed in Jubail. See Fig 13.

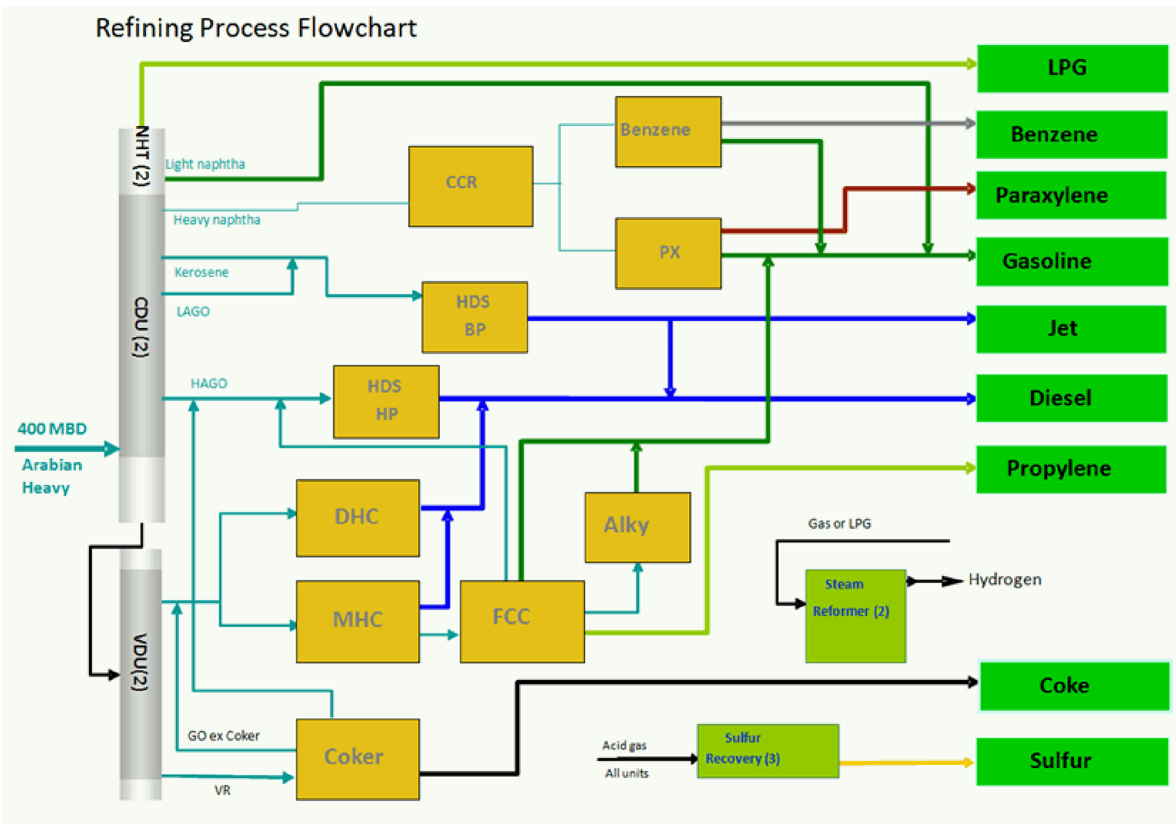

Figure 13: SATORP Refinery
Source: SATORP website.

This is a true state of the art refinery ($10+ billion price tag) and is optimised for the production of petrochemical intermediates and transportation fuels. It employs two hydrocrackers and a petrochemical FCC. The DHC is a distillate hydrocracker optimised for the production of diesel, and the MHC is a mild hydrocracker which is optimised to produce hydrowax feed for the FCC. This hydrocracker is effectively a feed pre-treatment unit. The propylene from the FCC will be something like 20% of the feed charge and there will be a similar amount of C4's which are sent to a sulphuric acid alkylation unit. The CCR is a platformer that will feed an aromatics plant for the production of benzene and para-xylene (PX). Para-xylene is the precursor for PTA- pure terephthalic acid which is used in PET resins - polyester. The delayed coker gets around the high conradson carbon in the crude charge (Manifa crude) which would be difficult and expensive to treat in any process other than carbon rejection. Conradson carbon is essentially the condensed hydrocarbon molecules that are primarily made up of asphaltenes. Coking is effectively the only option open due to the very high asphaltene content. In the longer term, my belief is that the light naphtha will be used as steam cracker feed in two units being planned next to the refinery. NHT refers to naphtha hydrotreater. See Table 3: Manifa SARA Assay from Aramco JOT spring 2012 p47 (SARA = saturates,aromatics, resins, asphaltenes) Note this is for the whole crude not the reduced crude.

R servoir	Saturates, %	Aromatics, %	R sin , %	Asphaltenes, %
LR	21.5941	49.5189	8.4393	20.4471
UR	44.1020	40.6537	4.9002	10.3441
M	39.7576	43.9718	6.7747	9.5[a]
M	39.8275	44.5000	4.6725	11.0[a]

Table 4. SARA test results of different Manifa oil samples (The asphaltenes content in these samples was obtained from the correlation of SARA test data with asphaltenes content[29])

Table 3: SARA for Manifa Crude
Source data for Pricing is Platts and OPEC monthly bulletin. Link
http://www.saudiaramco.com/en/home/news/publications-and-reports/saudi-a...

The Foster Wheeler graphic, Figure 14, below summarises the options for residue conversion, based on Atmospheric Residue 343 deg C +

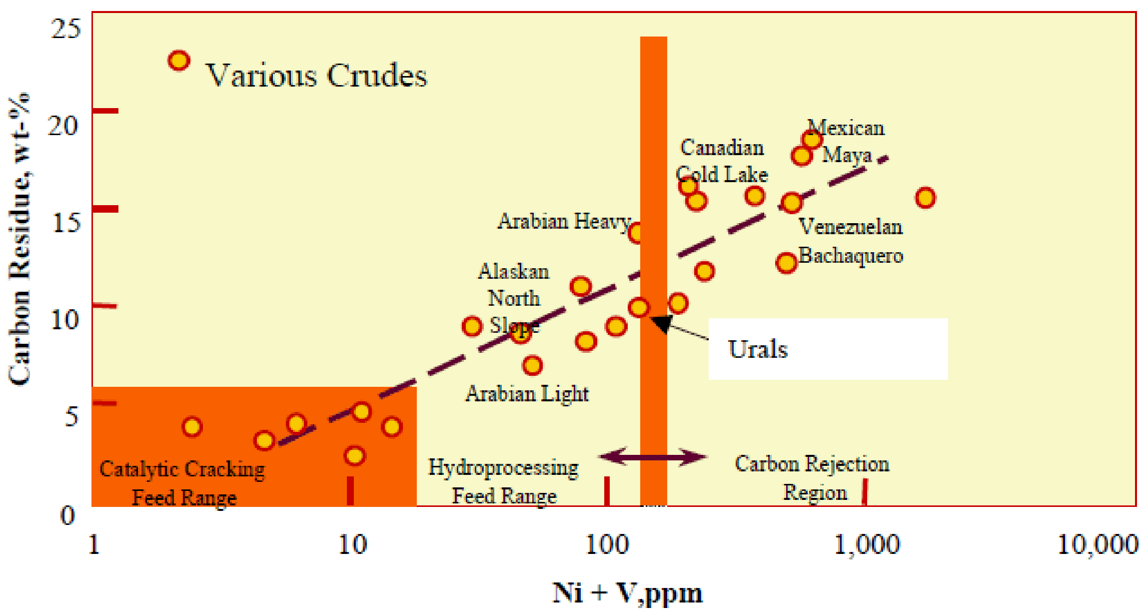

Figure 14: Options for Residue conversion
Source Foster Wheeler ERTC paper 2002 Data form SFA Pacific
http://www.fwcparts.com/publications/tech_papers/files/ERTC%202002%20-%2...

Future Product Demand: Can Refineries Adjust?

In a presentation recently given by Europia (European Petroleum Industries Association) the fuel mix for 2007 was compared with that anticipated for 2030 in Europe. The projection is not at all comforting as the fuel pool will be made up of 60% middle distillates, gasoline making up less than 10% of the demand, and jet exceeding gasoline demand. How would this demand be fulfilled? Not with the existing assets that is for sure and there has to be an environment in the EU that encourages the refiners to invest in the necessary upgrades, similar to what Repsol has done in Cartegena. Figure 15 demonstrates the challenge.

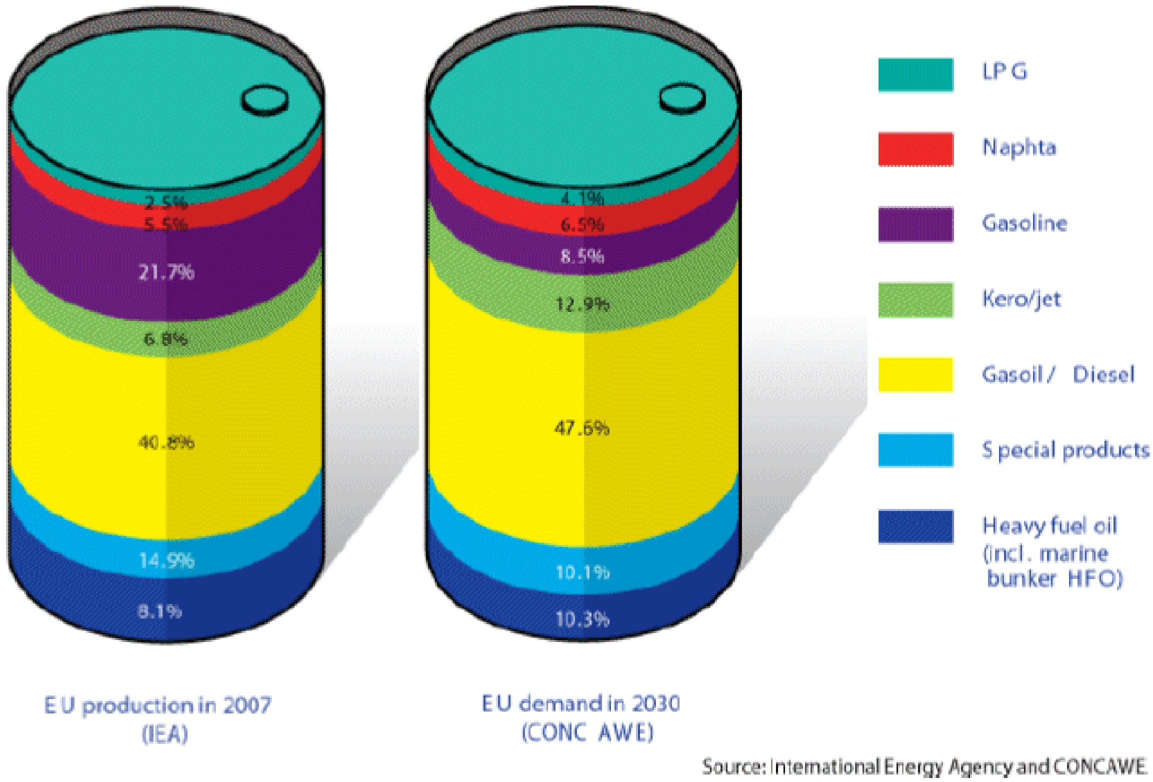

Figure 15: Actual and Projected EU product demand

At the European refining conference in March 2012, the large European refiner Total revealed that they counted 28 million tonnes/annum (520 kbd) of Mild Hydrocracking capacity announced in the next 5-6 years with a likelihood that 80% of this capacity will be installed. No new FCC capacity will be installed and some FCC capacity reductions can be expected as where the VGO feed is mildly hydrocracked it reduces the available feed for the FCCU's. Reducing the feed flow to the FCC would allow a MILO type operation without having to invest in the FCC gas handling system i.e. light olefine production can be maintained as can a better quality LCO (FCC diesel) and FCC gasoline is reduced. A win-win approach. Moreover the FCC gasoline that is produced tends to have a higher octane number. This approach is the low-cost version compared to investing in a full blown Hydrocracker either with single stage recycle or two stages, which run at much higher pressures, and come with a hefty price tag. The problem is that most of the hydrocracker projects identified are not in Western Europe where most of the refining assets are but in Eastern Europe. As an EU citizen, I watch with amazement that Greece intends to build 2 hydrocrackers - with whose money I wonder? See Figure 16:

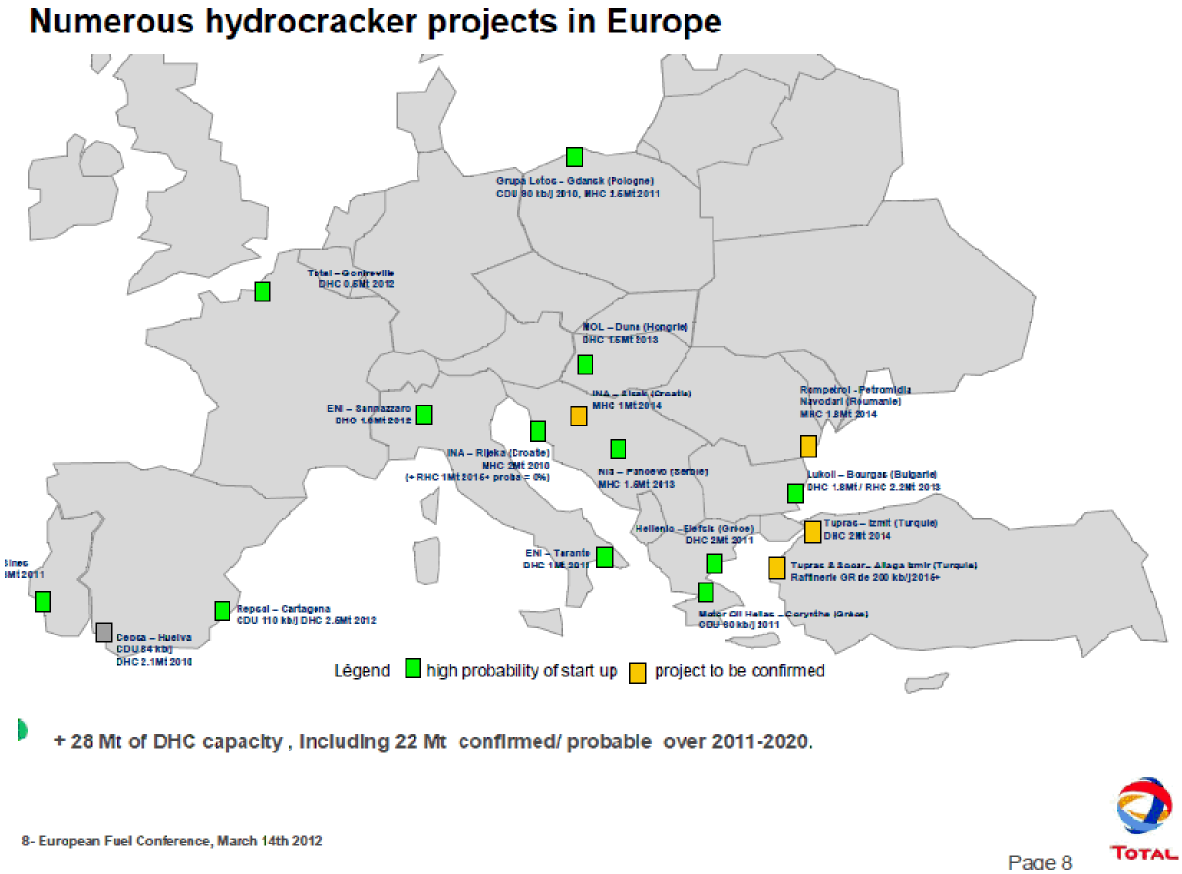

Figure 16: New EU DHC capacity

This will give some relief to the refineries in the East, but those refineries in the West are not investing anywhere near fast enough and however one looks at the situation, closure of refining assets is the likely scenario. Moreover, what we are seeing in western Europe is the purchase of refineries by non-integrated, often opportunistic players, which is not likely to result in the investment needed to bring these assets up to a standard to compete. When, not if, these assets close, then they will be gone for good, as the likelihood of them ever starting up again will be remote. However, the longer these marginal assets continue to operate whilst burning money, then the longer and worse the pain will be on the rest. Maybe the BP and Shell exit strategies saved them money in the short term, but in the longer term it remains to be seen. The situation in the US is not much better. There are many US refining assets that are past their best, and though the situation is not as bad as in Europe, it can only be a matter of time. Maybe this is a story for another day.